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# Docket No. 150007-EI
## Comprehensive Exhibit List for Entry into Hearing Record
## November 2, 2015

| EXH # | Witness | I.D. # As Filed | Exhibit Description | Issue Nos. | Entered |
|---|---|---|---|---|---|
| **STAFF** | | | | | |
| 1 | | Exhibit List | Comprehensive Exhibit List | | |
| **FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)** | | | | | |
| 2 | R.R. Labauve | RRL-1 | FPL Supplemental CAIR/MATS/CAVR Filing | 4 | **stipulated** |
| 3 | R.R. Labauve | RRL-2 | Summary of Coal Combustion Residuals Rule | 9A | **Stipulated** |
| 4 | R.R. Labauve | RRL-3 | Letter from United States Fish and Wildlife Service ("USFWS") requiring action for manatee protection at the CCEC | 3 | **stipulated** |
| 5 | R.R. Labauve | RRL-4 | Proposed conceptual changes to the manatee heating system at the CCEC | 3 | **stipulated** |
| 6 | Terry J. Keith | TJK-1 | Appendix I Environmental Cost Recovery Final True-up January 2014 – December 2014 Commission Forms 42-1A through 42-9A | 1-8, 13 | **stipulated** |
| 7 | Terry J. Keith | TJK-2 | Appendix I Environmental Cost Recovery Actual/Estimated Period January 2015 - December 2015 Commission Forms 42-1E through 42-9E | 1-8, 9B, 13 | **stipulated** |

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| 8 | Terry J. Keith | TJK-3 | Appendix I<br>Environmental Cost Recovery Projections January 2016 – December 2016<br>Commission Forms 42-1P through 42-8P | 1-8, 9B, 13 | **stipulated** |
| **DUKE ENERGY FLORIDA, LLC (DEF) – (DIRECT)** | | | | | |
| 9 | Michael Delowery | TGF-5 | Form 42-5P, page 20 of 22 | 1-3 | **stipulated** |
| 10 | Thomas G. Foster | TGF-1 | Forms 42-1A - 42-9A January 2014 – December 2014 (**Confidential**) | 1-8, 10A, 10B, 13 | **stipulated** |
| 11 | Thomas G. Foster | TGF-2 | Capital Program Detail January 2014 – December 2014 (**Confidential**) | 1-8, 10A, 10B, 13 | **stipulated** |
| 12 | Thomas G. Foster | TGF-3 | Forms 42-1E – 42-9E January 2015 – December 2015 | 1-8, 10A, 10B, 13 | **stipulated** |
| 13 | Thomas G. Foster | TGF-4 | Capital Program Detail January 2015 – December 2015 | 1-8, 10A, 10B, 13 | **stipulated** |
| 14 | Thomas G. Foster | TGF-5 | Forms 42-1P – 42-8P January 2016 – December 2016 | 1-8, 10A, 10B, 13 | **stipulated** |
| 15 | Thomas G. Foster | TGF-6 | Capital Program Detail January 2016 – December 2016 | 1-8, 10A, 10B, 13 | **stipulated** |
| 16 | Garry Miller | TGF-5 | Form 42-5P, pages 22 of 22 | 2, 3, 10A | **stipulated** |
| 17 | Jeffrey Swartz | JS-1 | Crystal River Clean Air Projects Organizational Chart | 1-3 | **stipulated** |
| 18 | Jeffrey Swartz | TGF-5 | Form 42-5P, pages 7 and 21 of 22 | 1-3 | **stipulated** |
| 19 | Patricia Q. West | PQW-1 | Review of Integrated Clean Air Compliance Plan | 1-3 | **stipulated** |
| 20 | Patricia Q. West | TGF-5 | Form 42-5P, pages 1-4, 6-7 and 8-19 of 22 | 1-3 | **stipulated** |
| **TAMPA ELECTRIC COMPANY (TECO) – (DIRECT)** | | | | | |

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|---|---|---|---|---|---|
| 21 | Penelope A. Rusk | PAR-1 | Final Environmental Cost Recovery Commission Forms 42-1A through 42-9A for the period January 2014 through December 2014 | 1, 2, 3, 4, 5, 6, 7, 8, 13 | **stipulated** |
| 22 | Penelope A. Rusk | PAR-2 | Environmental Cost Recovery Commission Forms 42-1E through 42-9E for the Period January 2015 through December 2015 | 1, 2, 3, 4, 5, 6, 7, 8, 13 | **stipulated** |
| 23 | Penelope A. Rusk | PAR-3 | Forms 42-1P through 42-8P Forms for the January 2016 through December 2016 | 1, 2, 3, 4, 5, 6, 7, 8, 13 | **stipulated** |
| **GULF POWER COMPANY (GULF) – (DIRECT)** | | | | | |
| 24 | J. O. Vick | JOV-1 | CCR regulation; Draft Plant Scholz NPDES industrial wastewater permit; Proposed ELG regulation | 1, 2, 3, 11A, 12A | **stipulated** |
| 25 | C. S. Boyett | CSB-1 | Calculation of Final True-up 1/14 through 12/14 | 1, 2, 3, 4, 5, 6, 7, 8, 11B, 12B, 13 | **stipulated** |
| 26 | C. S. Boyett | CSB-2 | Calculation of Estimated True-up 1/15 through 12/15 | 1, 2, 3, 4, 5, 6, 7, 8, 11B, 12B, 13 | **stipulated** |
| 27 | C. S. Boyett | CSB-3 | Calculation of Projection 1/16 through 12/16 | 1, 2, 3, 4, 5, 6, 7, 8, 11B, 12B, 13 | **stipulated** |
| **STAFF** | | | | | |
| 28 | | Staff's Exhibit #28 | FPL's Responses to Staff's First Set of Interrogatories, Nos. 1-8. *[Bates Nos. 00001-00012]* | 1, 4 | **stipulated** |
| 29 | | Staff's Exhibit #29 | FPL's Responses to Staff's Second Set of Interrogatories, Nos. 10-18. *[Bates Nos. 00013-00026]* | 2, 4, 9A | **stipulated** |
| 30 | | Staff's Exhibit #30 | FPL's Responses to Staff's Third Set of Interrogatories, Nos. 19-21. *[Bates Nos. 00027-00044]* | 3, 4, 7 | **stipulated** |

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| 31 | | Staff's Exhibit #31 | Commission Staff Final Audit Report for Florida Power & Light Company, dated June 10, 2015.<br>*[Bates Nos. 00045-00054]* | 1, 4 | **stipulated** |
| 32 | | Staff's Exhibit #32 | Florida Power & Light Company notification of new environmental projects, dated July 1, 2015.<br>*[Bates Nos. 00055-00060]* | 9A | **stipulated** |
| 33 | | Staff's Exhibit #33 | DEF's Responses to Staff's First Set of Interrogatories, Nos. 1-4.<br>*[Bates Nos. 00061-00068]* | 1, 4 | **stipulated** |
| 34 | | Staff's Exhibit #34 | DEF's Responses to Staff's Second Set of Interrogatories, Nos. 5-12.<br><br>DEF's Supplemental Response to Staff's Second Set of Interrogatories, No. 10.<br>*[Bates Nos. 00069-00083]* | 2, 4 | **stipulated** |
| 35 | | Staff's Exhibit #35 | DEF's Responses to Staff's Third Set of Interrogatories, No. 13.<br>*[Bates Nos. 00084-00086]* | 3, 4 | **stipulated** |
| 36 | | Staff's Exhibit #36 | Commission Staff Final Audit Report for Duke Energy Florida Inc., dated June 2, 2015.<br>*[Bates Nos. 00087-00096]* | 1, 4 | **stipulated** |
| 37 | | Staff's Exhibit #37 | Duke Energy Florida Letter advising of new environmental projects, dated July 1, 2015.<br>*[Bates Nos. 00097-00100]* | 10A | **stipulated** |
| 38 | | Staff's Exhibit #38 | TECO's Responses to Staff's First Set of Interrogatories, Nos. 1-2.<br>*[Bates Nos. 00101-00106]* | 1, 4 | **stipulated** |
| 39 | | Staff's Exhibit #39 | TECO's Responses to Staff's Second Set of Interrogatories, No. 3.<br>*[Bates Nos. 00107-00111]* | 3, 4 | **stipulated** |

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| 40 | | Staff's Exhibit #40 | Commission Staff Final Audit Report for Tampa Electric Company, dated June 4, 2015. *[Bates Nos. 00112-00121]* | 1, 4 | **stipulated** |
| 41 | | Staff's Exhibit #41 | Gulf's Responses to Staff's First Set of Interrogatories, No. 1. *[Bates Nos. 00122-00125]* | 1, 4 | **stipulated** |
| 42 | | Staff's Exhibit #42 | Gulf's Responses to Staff's Second Set of Interrogatories, Nos. 2-7. *[Bates Nos. 00126-00137]* | 2, 4, 11A, 12A | **stipulated** |
| 43 | | Staff's Exhibit #43 | Gulf's Responses to Staff's Third Set of Interrogatories, Nos. 8-10. *[Bates Nos. 00138-00143]* | 3, 4, 11A, 12A | **stipulated** |
| 44 | | Staff's Exhibit #44 | Commission Staff Final Audit Report for Gulf Power Company, dated June 11, 2015. *[Bates Nos. 00144-00153]* | 1, 4 | **stipulated** |
| 45 | | Staff's Exhibit #45 | Gulf Power Company notification of new environmental projects, dated July 1, 2015. *[Bates Nos. 00154-00159]* | 2, 3, 4, 11A, 12A | **stipulated** |

## *OTHER HEARING EXHIBITS*

| Exhibit Number | Witness | Party | Description | Moved In/Due Date of Late Filed |
|---|---|---|---|---|
| 46 | | OPC/Gulf | Deferral Stipulation for Plant Scholz CCR Unit 1 | |

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 2
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: R.R. Labauve RRL-1



**FLORIDA POWER & LIGHT COMPANY**
**DOCKET NO. 150007-EI**
**ENVIRONMENTAL COST RECOVERY CLAUSE**
**FPL SUPPLEMENTAL CAIR/MATS/CAVR FILING**
**APRIL 1, 2015**

**Per Order No. PSC-14-0643-FOF-EI, issued on November 4, 2014, the discussion below provides FPL's current estimates of project activities and associated costs related to its Clean Air Interstate Rule ("CAIR"), Mercury and Air Toxics Standards ("MATS"), and Clean Air Visibility Rule ("CAVR")/Best Available Retrofit Technology ("BART") projects.**

**Clean Air Interstate Rule ("CAIR") Compliance Project Update – now Cross State Air Pollution Rule:**

**Status of CAIR Rule Revision** - On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") vacated the CSAPR and remanded it to the Environmental Protection Agency ("EPA"), directing the EPA to continue administering the CAIR pending promulgation of a "valid replacement" rule. The Court denied all petitions for rehearing on January 24, 2013. On June 24, 2013, the U.S. Supreme Court granted the United States' and environmental group petitions asking the Court to review the D.C. Circuit's decision (EPA v. EME Homer City Generation, L.P.). The three issues before the Supreme Court were whether the D.C. Circuit lacked jurisdiction; if the EPA could validly impose Federal Implementation Plan bypassing the State Implementation Plan ("SIP") process and state discretion; and whether the EPA acted arbitrarily in defining "significant contribution", which was most of the focus of the court's hearing before eight of the nine Justices. On April 29, 2014, the U.S. Supreme Court issued an opinion upholding the CSAPR. The Court's opinion reversed the D.C. Circuit's decision.

On June 26, 2014, the EPA filed a motion in the D.C. Circuit requesting that the court lift the stay of the CSAPR. The EPA also requested that the court extend the CSAPR's compliance deadlines by three years, so that the Phase 1 emissions budgets apply in 2015 and 2016 (instead of 2012 and 2013), and the Phase 2 emissions budgets apply in 2017 and beyond (instead of 2014 and beyond). On October 23, 2014, the D.C. Circuit granted the EPA's request that the stay be lifted. On December 3, 2014 the EPA published in the Federal Register an interim final rule addressing compliance deadlines for the CSAPR and issued a Notice of Data Availability ("NODA"). The EPA's interim final rule tolls compliance dates three years, such that they begin in January 2015. The NODA provides allowance allocation changes that reflect changes made to the CSAPR subsequent to the final rule and "revintaging" original allowances forward by three years. On February 25, 2015 the D.C. Circuit heard oral argument on the EPA's rejection of the SIPs for 22 states as insufficient under the "good neighbor" provision of the Clean Air Act when it finalized the CSAPR. A decision from the Court is expected by the Summer of 2015. FPL will be working with the EPA during the rulemaking to address the Court's decision on the CSAPR to ensure that Florida in general and our facilities in particular receive their fair allocation of allowances.

**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 on SJRPP were accomplished in 2009 with the controls on both units being placed into service in 2010. FPL's ownership share of the total CAIR capital cost for installation of the SCR and Ammonia Injection System is $55.3 million.

Estimated CAIR annual O&M expenses for 2015 are approximately $32,000 (FPL's 20% ownership) for operation of the SCR for increased mercury co-benefit removal to comply with the MATS rule. Ongoing O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment.

**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 2014 is $398.9 million. In 2014 a third layer of catalyst was added to the SCR. Planned construction activities in 2015 include the addition of bromine injection to the SCR and completion of site restoration for the FGD and the wrap-up of the FGD completion project which began in 2013. Site restoration work includes paving/repaving roadways, reclaiming site storage areas, repairing areas damaged during construction and removing temporary facilities to return the site to the condition it was at the beginning of the construction project. FPL estimates its share of the Scherer Unit 4 CAIR capital costs for projects planned in 2015 to be $1.54 million.

FPL has estimated annual O&M for operation of the SCR, FGD, and common plant facilities supporting the controls at $3.88 million for 2015. 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 handling operation, FGD operations, FGD tower and auxiliary equipment maintenance.

**800 MW unit cycling project**– FPL completed construction work associated with this project in 2011.

Total capital costs for the 800 MW unit cycling project are $137.2 million. Projected O&M annual expenses are $0.569 million in 2015 primarily for treatment of condenser tube fouling.

**Continuous Emissions Monitoring System ("CEMS") Plan for Gas Turbines ("GT")** - The Low Mass Emitting ("LME") CEMS under 40 CFR Part 75 have been installed, tested, and are now in operation at the Fort Myers, Port Everglades, and Fort Lauderdale Gas Turbine sites, as required by the CAIR and by the CSAPR.

FPL has projected that O&M expenses of $5,000 per year will be required for routine maintenance of these CEMS systems. It should be noted that the LME option is available for a GT only if its emissions remain under EPA-prescribed thresholds. While FPL has filed notice

that it intends to replace all but 2 GTs at the Lauderdale and Fort Myers plants, CEMS will still be needed for monitoring those sources.

**Purchases of allowances** – To comply with the CSAPR Ozone Season NOx program requirements, FPL must evaluate each year whether it needs to purchase CSAPR allowances. FPL has evaluated the proposed allowance allocations under the CSAPR and has projected that it will have sufficient allocated allowances to cover projected emissions in 2015.

Actual CAIR capital costs for 2014 are $4.453 million.

| CAIR CAPITAL COST ESTIMATES ($Millions) | | |
|---|---|---|
| **PROJECT** | **TOTAL PROJECT through 2014** | **2015 Projections** |
| SJRPP-SCR/Ammonia Injection System | 55.3 | 0 |
| Scherer-SCR/FGD | 398.9 | 1.54 |
| 800 MW Unit Cycling – Martin | 72.1 | 0 |
| 800 MW Unit Cycling – Manatee | 65.1 | 0 |
| CEMS at GTs | Capital project completed | 0 |
| Allowances | N/A | N/A |

Actual CAIR O&M expenses for 2014 are $5.03 million.

| CAIR O&M EXPENSE ESTIMATES ($Millions) | | |
|---|---|---|
| **PROJECT** | **TOTAL PROJECT through 2014** | **2015 Projections** |
| SJRPP-SCR/Ammonia Injection System | annual operating costs are on-going | 0.032 |
| Scherer-SCR/FGD | annual operating costs are on-going | 3.88 |
| 800 MW Unit Cycling – Martin | annual operating costs are on-going | 0.317 |
| 800 MW Unit Cycling – Manatee | annual operating costs are on-going | 0.252 |
| CEMS at GTs | annual operating costs are on-going | $0.005 |
| Allowances | N/A | N/A |

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

On March 15, 2005, the EPA issued the Clean Air Mercury Rule ("CAMR") to permanently cap and reduce mercury ("Hg") emissions from coal-fired power plants for the first time. In response to the EPA's CAMR, the Georgia Environmental Protection Division ("EPD") promulgated two major rules to implement Hg reductions within Georgia: a rule to adopt the CAMR federal Hg cap and trade program: Rule 391-3-1-.02(15) – "*Georgia Mercury Trading Rule*" and a Georgia state specific Multipollutant Rule: Rule 391-3-1-.02(2) (sss) – *"Multipollutant Control for Electric Utility Steam Generating Units"*, which became effective June 1, 2008. The Georgia Multipollutant Rule was promulgated to specify the implementation of specific air pollution control equipment for reductions of Hg, sulfur dioxide ("$SO_2$"), and nitrogen oxides ("NOx") emissions from identified coal-fired Electric Generating Units ("EGUs") within Georgia. Section 4(i) of the Georgia Multipollutant Rule requires that Scherer Unit 4 may not be operated after April 30, 2010, unless it is equipped and operated with sorbent injection and a baghouse for the control of Hg emissions.

On February 8, 2008, the District of Columbia Circuit Court of Appeals, in a unanimous decision, vacated the EPA's CAMR. However, installation of Hg controls, and associated continuous Hg emissions monitoring that would have been needed to comply with the CAMR requirements remain necessary to comply with the requirements of the Georgia Multipollutant Rule; therefore installation of Hg controls on Plant Scherer Unit 4 must continue. The vacatur of the CAMR does not change the compliance obligations at Plant Scherer, including FPL's share of Unit 4. In addition, on December 16, 2011, the EPA published its final Mercury and Air Toxics Standards ("MATS") rule as a replacement for the CAMR. The EPA's MATS rule sets limits on emissions of Toxic Metal Hazardous Air Pollutants ("HAPs"), including Hg, limits on emissions of acid gasses, and work practice standards for emissions of organic HAPs. FPL has reviewed the compliance requirements of the MATS rule and believes that controls installed on Scherer Unit 4 for compliance with the CAIR, the CAMR, and the Georgia Multipollutant Rule will allow the unit to meet the rule's emissions specifications for HAPs. Specifically, FPL is complying with the 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) for compliance with the Georgia Multipollutant Rule.
3. Installation of HgCEMS on SJRPP Units 1 and 2 (completed in 2008 prior to the vacatur of the CAMR). Hg CEMS are required to comply with the MATS rule.

FPL's share of the capital cost associated with the installation of Hg CEMS at SJRPP is $0.4 million. Testing has confirmed that use of low sulfur coal containing low Hg concentrations in SJRPP Units 1 and 2 boilers with an increase in the use of dibasic acid in the FGD and operation of the SCR will allow the units to meet the MATS emissions limits. JEA and FPL concluded that the clean fuel option was the most cost-effective option for compliance with the MATS emissions limits. Compliance requirements for the MATS emissions limits were scheduled to go

into effect on April 16, 2015. However, Georgia Power Company, operator of Plant Scherer, filed a request with the Georgia Environmental Protection Division ("GAEPD") for an extension of the compliance deadline until April 2016 to complete monitoring changes needed for compliance with the EPA's November 2014 revision of the MATS rule. The GAEPD granted the extension request in March 2015.

Projected annual O&M associated with operation of the Hg controls includes purchase of new sorbent, disposal of spent sorbent, replacement of filter bags, and maintenance activities associated with the baghouse and sorbent injection system, and the maintenance costs associated with FPL's share of the Scherer Unit 4 Hg CEMS. For 2015, projected MATS O&M expenses for Plant Scherer are $2.297 million and for SJRPP are $0.110 million, primarily for purchase and disposal of sorbents and replacement of bags at Plant Scherer and operation and maintenance of the Hg monitors at SJRPP.

On December 21, 2011, the EPA issued the final MATS rule, which has the effect of requiring ESPs for the 800 MW oil-fired units. Construction of the ESPs was completed in 2014. Actual capital costs for construction of the ESPs through 2014 are $209.4 million. FPL's costs for compliance with the MATS rule include Project 33: the SJRPP Mercury CEMS project and the Scherer Sorbant Injection/Baghouse/Mercury CEMS, and Project 45 (the 800 MW ESP project).

Actual MATS capital costs for 2014 are $55.3 million.

| **MATS CAPITAL COST ESTIMATES ($Millions)** | | |
|---|---|---|
| **PROJECT** | **TOTAL PROJECT through 2014** | **2015 Projections** |
| SJRPP-Mercury CEMS | 0.4 | 0.14 |
| Scherer-Sorbent Injection/Baghouse/ Mercury CEMS | 108.62 | 0.001 |
| 800 MW ESP PMR/PMT | 209.4 | 7.831 |

Actual MATS O&M expenses for 2014 are $2.2 million.

| **MATS O&M EXPENSE ESTIMATES ($Millions)** | | |
|---|---|---|
| **PROJECT** | **TOTAL PROJECT through 2014** | **2015 Projection** |
| SJRPP-Mercury CEMS | 0.0 | 0.11 |
| Scherer-Sorbent Injection/Baghouse/ HgCEMS | (annual operating costs are on-going) | 2.3 |
| 800 MW ESP PMR/PMT | N/A | 1.34 |

**CAVR / BART Project Update:**

FPL successfully concluded negotiations with the Florida Department of Environmental Protection ("FDEP" or "the Department") regarding Turkey Point Units 1 and 2 in February 2009, with the Department accepting FPL's proposed plan to comply with the BART requirements under the Regional Haze program. In 2011, FPL negotiated with the FDEP changes to its compliance plan at Turkey Point to address changes to the state's plan as a result of the CSAPR's impact on the Regional Haze SIP. FPL proposed to remove the requirement to install new multi-cyclone dust collectors and instead proposed to reduce emissions of $SO_2$ through use of 0.7% sulfur residual fuel oil and to commit to no longer burning fossil fuels in the Unit 2 boiler effective immediately, and to take a significant reduction in fuel oil firing in Unit 1 boiler beginning in 2013. In 2011, the FDEP identified concerns with the analysis of the Putnam units, which were projected to exceed the criteria threshold. FPL retained a consultant in 2012 to prepare modeling required by the state to demonstrate that the Putnam plant and the Manatee and Martin 800 MW units do not exceed the criteria thresholds. The FDEP contends that visibility improvements at Florida's Class 1 Areas will meet the Reasonable Progress glide slope in 2018 by way of existing air rules. FPL does not anticipate that installation of additional controls will be required for compliance with the Reasonable Progress requirements as a result of FPL's retirement of Turkey Point Unit 2, retirement of both combined cycle units at the Putnam plant and installation of ESPs on the 800 MW units.

When the EPA issued its CSAPR, Florida was no longer included in the particulate matter portion of the rule, removing previously affected units from the annual NOx and $SO_2$ requirements. Because of the regulatory uncertainty from the status of the CSAPR and the CAIR at that time, FPL was required to perform a full 5-factor BART Determination for $SO_2$ and NOx at Turkey Point Units 1 and 2, Manatee Units 1 and 2, and Martin Units 1 and 2. The EPA has approved Florida's SIP which adopts FPL's BART compliance plan. FPL's results from the 5-factor analysis demonstrated that FPL's affected fossil units did not exceed visibility threshold values and were in compliance with the Regional Haze requirements. The EPA subsequently approved the SIP for Regional Haze that included FPL's compliance plan.

Actual CAVR capital costs through 2014 are $0, and FPL does not anticipate any future compliance costs for CAVR at this time. Actual CAVR O&M expenses through 2014 are $0.056 million. FPL did not project any O&M costs for CAVR in 2014 and does not anticipate any further O&M costs at this time. Actual costs in 2014 for compliance with the BART/CAVR requirements were $0. FPL does not anticipate CAVR/BART costs during the 2015 period.

| **CAVR/BART O&M EXPENSE ESTIMATES ($Millions)** | | |
|---|---|---|
| **PROJECT** | **TOTAL PROJECT through 2014** | **2015 Projections** |
| Reasonable Progress Control Technology Determination | 0.056 | 0.0 |

AUTHENTICATED U.S. GOVERNMENT INFORMATION GPO

# FEDERAL REGISTER

Vol. 80 Friday,
No. 74 April 17, 2015

Part II

## Environmental Protection Agency

40 CFR Parts 257 and 261
Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities; Final Rule

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 3
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: R.R. Labauve RRL-2

**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Parts 257 and 261**

**[EPA–HQ–RCRA–2009–0640; FRL–9919–44–OSWER]**

**RIN–2050–AE81**

## Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** The Environmental Protection Agency (EPA or the Agency) is publishing a final rule to regulate the disposal of coal combustion residuals (CCR) as solid waste under subtitle D of the Resource Conservation and Recovery Act (RCRA). The available information demonstrates that the risks posed to human health and the environment by certain CCR management units warrant regulatory controls. EPA is finalizing national minimum criteria for existing and new CCR landfills and existing and new CCR surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, except in limited circumstances. It also requires the closure of any CCR landfill or CCR surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Finally, those CCR surface impoundments that do not receive CCR after the effective date of the rule, but still contain water and CCR will be subject to all applicable regulatory requirements, unless the owner or operator of the facility dewaters and installs a final cover system on these inactive units no later than three years from publication of the rule. EPA is deferring its final decision on the Bevill Regulatory Determination because of regulatory and technical uncertainties that cannot be resolved at this time.

**DATES:** This final rule is effective on October 14, 2015.

**ADDRESSES:** EPA has established three dockets for this regulatory action under Docket ID No. EPA–HQ–RCRA–2009–0640, Docket ID No. EPA–HQ–RCRA–2011–0392, and Docket ID No. EPA–HQ–RCRA–2012–0028. All documents in these dockets are available at *http://www.regulations.gov*. Although listed in the index, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) 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 hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the OSWER Docket, EPA/DC, WJC West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460. 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 OSWER Docket is 202–566–0276.

**FOR FURTHER INFORMATION CONTACT:** For questions on technical issues: Alexander Livnat, Office of Resource Conservation and Recovery, Environmental Protection Agency, 5304P; telephone number: (703) 308–7251; fax number: (703) 605–0595; email address: *livnat.alexander@epa.gov*, or Steve Souders, Office of Resource Conservation and Recovery, Environmental Protection Agency, 5304P; telephone number: (703) 308–8431; fax number: (703) 605–0595; email address: *souders.steve@epa.gov*. For questions on the regulatory impact analysis: Richard Benware, Office of Resource Conservation and Recovery, Environmental Protection Agency, 5305P; telephone number: (703) 308–0436; fax number: (703) 308–7904; email address: *benware.richard@epa.gov*. For questions on the risk assessment: Jason Mills, Office of Resource Conservation and Recovery, Environmental Protection Agency, 5305P; telephone number: (703) 305–9091; fax number: (703) 308–7904; email address: *mills.jason@epa.gov*.

For more information on this rulemaking please visit *http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/index.htm*.

**SUPPLEMENTARY INFORMATION:**

### A. Does this action apply to me?

This rule applies to all coal combustion residuals (CCR) generated by electric utilities and independent power producers that fall within the North American Industry Classification System (NAICS) code 221112 and may affect the following entities: Electric utility facilities and independent power producers that fall under the NAICS code 221112. The industry sector(s) identified above may not be exhaustive; other types of entities not listed could also be affected. The Agency's aim is to provide a guide for readers regarding those entities that potentially could be affected by this action. To determine whether your facility, company, business, organization, etc., is affected by this action, you should refer to the applicability criteria discussed in Unit VI.A. of this document If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

### B. What actions are not addressed in this rule?

This rule does not address the placement of CCR in coal mines. The U.S. Department of Interior (DOI) and, as necessary, EPA will address the management of CCR in minefills in separate regulatory action(s), consistent with the approach recommended by the National Academy of Sciences, recognizing the expertise of DOI's Office of Surface Mining Reclamation and Enforcement in this area. See Unit VI of this document for further details. This rule does not regulate practices that meet the definition of a beneficial use of CCR. Beneficial uses that occur after the effective date of the rule need to determine if they comply with the criteria contained in the definition of ''beneficial use of CCRs.'' This rule does not affect past beneficial uses (*i.e.*, uses completed before the effective date of the rule.) See Unit VI of this document for further details on proposed clarifications of beneficial use. Furthermore, CCR from non-utility boilers burning coal are also not addressed in this final rule. EPA will decide on an appropriate action for these wastes through a separate rulemaking effort. See Unit IV of this document for further details. Finally, this rule does not apply to municipal solid waste landfills (MSWLFs) that receive CCR for disposal or use as daily cover.

### C. The Contents of This Preamble Are Listed in the Following Outline

I. Executive Summary
II. Statutory Authority
III. Background
IV. Bevill Regulatory Determination Relating to CCR From Electric Utilities and Independent Power Producers
V. Development of the Final Rule—RCRA Subtitle D Regulatory Approach

VI. Development of the Final Rule—Technical Requirements
VII. Summary of Major Differences Between the Proposed and Final Rules
VIII. Implementation Timeframes for Minimum National Criteria and Coordination With Steam Electric ELG Rule
IX. Implementation of the Minimum Federal Criteria and State Solid Waste Management Plans
X. Risk Assessment
XI. Summary of Damage Cases
XII. Summary of Regulatory Impact Analysis
XIII. Uniquely Associated Wastes
XIV. Statutory and Executive Order Reviews

## I. Executive Summary

This rule establishes nationally applicable minimum criteria for the safe disposal of coal combustion residuals in landfills and surface impoundments. This section summarizes these criteria. Detailed discussions of the criteria and the Agency's rationale for finalizing these requirements are provided in Unit VI of this document.

### *A. What are coal combustion residuals?*

Coal combustion residuals (CCR) are generated from the combustion of coal, including solid fuels classified as anthracite, bituminous, subbituminous, and lignite, for the purpose of generating steam for the purpose of powering a generator to produce electricity or electricity and other thermal energy by electric utilities and independent power producers. CCR includes fly ash, bottom ash, boiler slag, and flue gas desulfurization materials. A description of the types of CCR can be found in the proposed rule (see 75 FR 35137).

CCR is one of the largest industrial waste streams generated in the U.S. In 2012, over 470 coal-fired electric utilities burned over 800 million tons of coal, generating approximately 110 million tons of CCR in 47 states and Puerto Rico. CCR may be generated wet or dry; however, this composition may change after generation. Some CCR is dewatered while other CCR is mixed with water to facilitate transport (*i.e.*, sluiced). CCR can be sent off-site for disposal or beneficial use or disposed in on-site landfills or surface impoundments. In 2012, approximately 40 percent of the CCR generated was beneficially used, with the remaining 60 percent disposed in surface impoundments and landfills. Of that 60 percent, approximately 80 percent was disposed in on-site disposal units. CCR disposal currently occurs at over 310 active on-site landfills, averaging over 120 acres in size with an average depth of over 40 feet, and at over 735 active on-site surface impoundments, averaging over 50 acres in size with an average depth of 20 feet.

### *B. Background*

The Agency first solicited comments on the regulation of CCR in a proposed rule published in the **Federal Register** on June 21, 2010. This proposal, under the Resource Conservation and Recovery Act (RCRA), addressed the risks from disposal of CCR generated from the combustion of coal at electric utilities and from independent power producers. Two regulatory options were proposed. Under the first option, EPA proposed to list CCR as special waste subject to regulation under subtitle C of RCRA, when destined for disposal in landfills or surface impoundments. Under this option, CCR would require ''cradle-to-grave'' management and would be subject to requirements for, among other things, composite liners, groundwater monitoring, structural stability requirements, corrective action, closure/post closure care and financial assurance. States would be required to adopt the rule before it went into effect and a permitting program would be established with direct federal oversight. The subtitle C option, as proposed, would also effectively result in the closure of all CCR surface impoundments.

Under the second option, EPA proposed to regulate the disposal of CCR under subtitle D of RCRA by issuing minimum national criteria. Similar to the subtitle C option, this option would require composite liners, groundwater monitoring, structural stability requirements, corrective action, and closure/post closure care. However, consistent with the available statutory authority under subtitle D, EPA proposed this option to be a self-implementing rule with no direct federal oversight, with an effective date six months after publication in the **Federal Register**. This option required all unlined surface impoundments to either retrofit to a composite liner or close within five years.

After reviewing all the comments and additional data received, EPA is promulgating this final rule to regulate the disposal of CCR as solid waste under subtitle D of RCRA. This rule addresses the risks from structural failures of CCR surface impoundments, groundwater contamination from the improper management of CCR in landfills and surface impoundments and fugitive dust emissions. The rule has also been designed to provide electric utilities and independent power producers generating CCR with a practical approach for implementation of the requirements and has established implementation timelines that take into account, among other things, other upcoming regulatory actions affecting electric utilities and site specific practical realities. In order to ease implementation of the regulatory requirements for CCR units with state programs, EPA is also providing the opportunity for states to secure approval of its CCR program through the State Solid Waste Management Plan (''SWMP''). EPA strongly recommends that states take advantage of this process by revising their SWMPs to address the issuance of the revised federal requirements in this final rule, and to submit revisions of these plans to EPA for review. EPA would then review and approve the revised SWMPs provided they demonstrate that the minimum federal requirements in this final rule will be met. In this way, EPA's approval of a revised SWMP signals EPA's opinion that the state SWMP meets the minimum federal criteria.

### *C. What types of CCR units are covered by this rule?*

The final rule applies to owners and operators of new and existing landfills and new and existing surface impoundments, including all lateral expansions of landfills and surface impoundments that dispose or otherwise engage in solid waste management of CCR generated from the combustion of coal at electric utilities and independent power producers. The requirements of the rule also apply to CCR units located off-site of the electric utilities' or independent power producers' facilities that receive CCR for disposal. In addition, the rule applies to certain inactive CCR surface impoundments (*i.e.*, units not receiving CCR after the effective date of the rule) at active electric utilities' or independent power producers' facilities, regardless of the fuel currently used at the facility to produce electricity (*e.g.* coal, natural gas, oil), if the CCR unit still contains CCR and liquids.

The requirements do not apply to: (1) CCR landfills that ceased receiving CCR prior to the effective date of the rule; (2) CCR units at facilities that have ceased producing electricity (or electricity and other thermal energy) prior to the effective date of the rule; (3) CCR generated at facilities that are not part of an electric utility or independent power producer, such as manufacturing facilities, universities, and hospitals; (4) fly ash, bottom ash, boiler slag, and flue gas desulfurization materials, generated primarily from the combustion of fuels (including other fossil fuels) other than coal, for the purpose of generating electricity unless the fuel burned

consists of more than fifty percent coal on a total heat input or mass input basis, whichever results in the greater mass feed rate of coal; (5) CCR that is beneficially used; (6) CCR placement at active or abandoned underground or surface coal mines; or (7) municipal solid waste landfills (MSWLF) that receive CCR.

*D. What minimum national criteria are being established for CCR landfills and CCR surface impoundments?*

This final rule establishes minimum national criteria for CCR landfills, CCR surface impoundments, and all lateral expansions of CCR units including location restrictions, liner design criteria, structural integrity requirements, operating criteria, groundwater monitoring and corrective action requirements, closure and post-closure care requirements, and recordkeeping, notification, and internet posting requirements.

*1. Location Restrictions.* To ensure there will be no reasonable probability of adverse effects on health or the environment from the disposal of CCR in CCR landfills, CCR surface impoundments, and all lateral expansions of CCR landfills and CCR surface impoundments (together ''CCR units''), this final rule establishes five location restrictions. The location criteria include restrictions relating to placement of CCR above the uppermost aquifer, in wetlands, within fault areas, in seismic impact zones, and in unstable areas. All of these location restrictions require the owner or operator of a CCR unit to demonstrate that they meet the specific criteria. As discussed elsewhere in this preamble, the five location restrictions apply to all new CCR landfills, all new and existing CCR surface impoundments, and all lateral expansions of CCR units; however, existing CCR landfills are only subject to the location restriction for unstable areas. Units that do not meet these restrictions can retrofit or make appropriate engineering demonstrations to meet this criteria. This final rule requires owner or operators of existing CCR units that cannot make the required demonstrations to close, while owners or operators of new CCR units and all lateral expansions who fail to make the required demonstrations are prohibited from placing CCR in the CCR unit.

*2. Liner Design Criteria.* The final rule also establishes liner design criteria to help prevent contaminants in CCR from leaching from the CCR unit and contaminating groundwater. All new CCR landfills, new CCR surface impoundments, and lateral expansions of CCR units must be lined with composite liner, which is a liner system consisting of two components—a geomembrane and a two-foot layer of compacted soil—installed in direct and uniform contact with one another. The final rule allows an owner or operator to construct a new CCR unit with an alternative composite liner, provided the alternative composite liner performs no less effectively than the composite liner. In addition, new landfills are required to operate with a leachate collection and removal system which is designed to remove excess leachate that may accumulate on top of the composite (or alternative composite) liner. Existing CCR landfills are not required to close or retrofit with a composite (or alternative composite) liner and a leachate collection and removal system. These existing CCR units can continue to receive CCR after this rule is in effect; however, the CCR units must meet all applicable groundwater monitoring and corrective action criteria to address any groundwater releases promptly. Existing CCR surface impoundments can also continue to operate as designed. However, if the existing CCR surface impoundment was not constructed with a composite (or alternative composite) liner or with at least two feet of compacted soil with a specified hydraulic conductivity, the rule would require the unit to retrofit or close if the CCR surface impoundment detects concentrations of one or more constituents listed in appendix IV at statistically significant levels above the groundwater protection standard established by the rule.

*3. Structural Integrity Requirements.* To help prevent the damages associated with structural failures of CCR surface impoundments, the final rule establishes structural integrity criteria for new and existing surface impoundments (and all lateral expansions) as part of the design criteria. While the applicability of the structural integrity requirements to individual CCR surface impoundments vary depending on factors such as dike heights and the potential for loss of life, environmental damage and economic loss if there is a dike failure, the final rule establishes requirements for owner or operators to conduct a number of structural integrity-related assessments regularly. These include: (1) Conducting periodic hazard potential classification assessments to assess the potential adverse incremental consequences that would occur if there was a failure of the CCR surface impoundment; (2) conducting periodic structural stability assessments by a qualified professional engineer to document whether the design, construction, operation and maintenance is consistent with recognized and generally accepted good engineering practices; and (3) conducting periodic safety factor assessments to document whether the CCR unit achieves minimum factors of safety for slope stability. If a CCR unit required to conduct a safety factor assessment fails to demonstrate that the unit achieves the specified factors of safety, the owner or operator must close the unit. In addition, certain CCR surface impoundments are required to develop an emergency action plan which defines the events and circumstances involving the CCR unit that represent an emergency and identifies the actions that will be taken in the event of a safety emergency.

*4. Operating Criteria.* The operating criteria include air criteria for all CCR units, run-on and run-off controls for CCR landfills, hydrologic and hydraulic capacity requirements for CCR surface impoundments, and periodic inspection requirements for all CCR units. These criteria address the day-to-day operations of CCR units and are established to prevent health and environmental impacts from CCR units. The air criteria address the pollution caused by windblown dust from CCR units, and require owners and operators to minimize CCR from becoming airborne at the facility. The run-on controls for CCR landfills minimize the amount of surface water entering the unit that will help prevent erosion, surface discharges of CCR in solution or suspension, and will mitigate the generation of landfill leachate, while run-off controls help prevent erosion, protect downstream surface water from releases from the unit, and minimize storm water run-off volume and velocity. CCR surface impoundments are subject to hydrologic and hydraulic capacity requirements to ensure the unit can safely handle flood flows, which will help prevent uncontrolled overtopping of the unit or erosion of the materials used to construct the surface impoundment. The final rule also requires periodic inspections of CCR units to identify any appearance of structural weakness or other conditions that are not consistent with recognized and generally accepted good engineering standards.

*5. Groundwater Monitoring and Corrective Action.* The groundwater monitoring and corrective action criteria require an owner or operator of a CCR unit to install a system of monitoring wells and specify procedures for sampling these wells, in addition to methods for analyzing the groundwater data collected, to detect the presence of

hazardous constituents (*e.g.,* toxic metals) and other monitoring parameters (*e.g.,* pH, total dissolved solids) released from the units. The final rule establishes a groundwater monitoring program consisting of detection monitoring, assessment monitoring and corrective action. Once a groundwater monitoring system and groundwater monitoring program has been established for a CCR unit, the owner or operator must conduct groundwater monitoring and, if the monitoring demonstrates an exceedance of a groundwater protection standard for any of the identified constituents in CCR, must initiate corrective action.

*6. Closure and Post-Closure Requirements.* The closure and post-closure care criteria require all CCR units to close in accordance with specified standards and to monitor and maintain the units for a period of time after closure, including the groundwater monitoring and corrective action programs. These criteria are essential to ensuring the long-term safety of closed CCR units. Closure of a CCR unit must be completed either by leaving the CCR in place and installing a final cover system or through removal of the CCR and decontamination of the CCR unit. The final rule establishes timeframes to initiate and complete closure activities, and authorize owners or operators to obtain time extensions due to circumstances beyond the facility's control. As discussed elsewhere in this preamble, the rule also establishes alternative closure procedures in situations where an owner or operator is closing a CCR unit, but has no alternative CCR disposal capacity or is permanently closing the coal-fired boiler unit in the foreseeable future. Finally, owners and operators are required to prepare closure and post-closure care plans describing these activities.

*7. Record Keeping, Notification, and Internet Posting Requirements.* The final rule requires owners or operators of CCR units to record certain information in the facility's operating record. In addition, owners and operators are required to provide notification to States and/or appropriate Tribal authorities when the owner or operator places information in the operating record, as well as to maintain a publicly accessible internet site for this information.

*8. Severability.* EPA intends that the provisions of this rule be severable. In the event that any individual provision or part of this rule is invalidated, EPA intends that this would not render the entire rule invalid, and that any individual provisions that can continue to operate will be left in place. The following tables provide a summary of the specific technical requirements applicable to existing and new CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units.

United States Department of the Interior
U. S. FISH AND WILDLIFE SERVICE
7915 BAYMEADOWS WAY, SUITE 200
JACKSONVILLE, FLORIDA 32256-7517

IN REPLY REFER TO:

August 24, 2015

Randall LaBauve, Vice President
Environmental Services
Florida Power and Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Re: Manatee carcasses found in Cape Canaveral Energy Center intake wells

Dear Mr. LaBauve:

The U.S. Fish and Wildlife Service (Service) was notified by Florida Power and Light Company (FP&L) staff of the presence of seventeen manatee carcasses in the Cape Canaveral Energy Center (CCEC) intake wells subsequent to modernization in April 2013.

The carcasses were recovered and examined by staff from the Florida Fish and Wildlife Conservation Commission's (FWC) Marine Mammal Pathobiology Lab. For some of the carcasses, FWC was able to determine that the animals had died prior to entering the intake wells. For the remaining carcasses, it was not possible to determine if the animals had died prior to appearing in the wells. As such, the Service is very concerned that CCEC operations may have caused the deaths of some of these manatees.

The Federal Endangered Species Act (ESA), as amended (16 U.S.C. 1531), and the Marine Mammal Protection Act, as amended (16 U.S.C. 1361), prohibit the take of the endangered manatee. Specifically, section 9 of the ESA prohibits those actions that harass, harm, wound, kill, trap, capture, or collect, and prohibit attempts to engage in any such conduct. Section 11 of the ESA provides for criminal sanctions, civil penalties, and injunctions for unauthorized takes or other violations of the ESA (16 U.S.C. § 1540). The Service may seek all three remedies. In addition; section 11 enables private citizens to pursue injunctions in order to prevent actions conducted by individuals or organizations that cause unauthorized takes. The civil penalties established in section 11(a)(1) are not more than $25,000 if the violation is done "knowingly" and $500 otherwise (16 U.S.C. § 1540(a)(1)). Section 11(b)(1) imposes a maximum criminal penalty of $50,000 and/or one year in jail against anyone who "knowingly" violates the ESA (16 U.S.C. § 1540(b)(1)). These penalties have since been increased by to a maximum per violation of $100,000 for individuals and $200,000 for corporations (18 U.S.C. §3571).

FPL is not authorized to take manatees. In order to avoid violating provisions of these acts, FP&L must develop and implement a suitable solution to prevent the future impingement of manatees in the intake wells. In the event that FP&L elects to not develop and implement a solution, the Service will refer this information to our Office of Law Enforcement and request

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 4
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: R.R. Labauve RRL-3

that any future manatee deaths that occur in the CCEC intake wells be investigated. We have been working with FP&L to develop a solution to address this concern and appreciate your efforts to conserve manatees.

If you have any questions regarding this response please contact Jim Valade of my staff at (904) 731-3116 or Jim_Valade@fws.gov.

Sincerely,

Jay B. Herrington
Field Supervisor

cc: FWC, Tallahassee (Ron Mezich)

# Project 41-Manatee Temporary Heating System

Proposed Conceptual Changes

Exhibit RRL-4

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 5
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: R.R. Labauve RRL-4

# APPENDIX I

## ENVIRONMENTAL COST RECOVERY
## COMMISSION FORMS 42-1A THROUGH 42-9A

## JANUARY 2014 - DECEMBER 2014
## FINAL TRUE-UP

TJK-1
DOCKET NO. 150007-EI
EXHIBIT_____
PAGES 1-44

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 6
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Terry J. Keith TJK-1

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

FORM: 42-1A

JANUARY 2014 THROUGH DECEMBER 2014

| | 2014 |
|---|---|
| 1. Over/(Under) Recovery for the Current Period (Form 42-2A, Line 5) | ($1,979,584) |
| 2. Interest Provision (Form 42-2A, Line 6) | $96 |
| 3. Total | ($1,979,488) |
| | |
| 4. Actual/Estimated Over/(Under) Recovery for the Same Period (1) | $1,185,137 |
| 5. Interest Provision | ($218) |
| 6. Total | $1,184,920 |
| | |
| 7. Net True-Up for the period | ($3,164,408) |

(1) Approved in Order No. PSC-14-0643 dated November 4, 2014

Note: Totals may not add up due to rounding

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

FORM: 42-2A

JANUARY 2014 THROUGH DECEMBER 2014

| | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. ECRC Revenues (net of Revenue Taxes) | $16,550,106 | $15,111,889 | $14,607,578 | $15,437,131 | $18,245,293 | $19,028,987 | $20,154,001 | $21,417,520 | $21,530,886 | $18,541,999 | $15,806,297 | $15,119,997 | $211,551,686 |
| 2. True-up Provision | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($2,364,901) |
| 3. ECRC Revenues Applicable to Period (Lines 1 + 2) | $16,353,031 | $14,914,814 | $14,410,503 | $15,240,056 | $18,048,218 | $18,831,912 | $19,956,926 | $21,220,445 | $21,333,811 | $18,344,924 | $15,609,222 | $14,922,922 | $209,186,785 |
| 4. Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| a. O&M Activities (Form 42-5A, Line 9) | $1,899,774 | $1,588,779 | $1,949,688 | $2,201,463 | $1,752,182 | $2,022,853 | $1,912,310 | $2,233,320 | $1,945,736 | $1,250,098 | $1,810,899 | $6,320,897 | $26,888,000 |
| b. Capital Investment Projects (Form 42-7A, Line 9) | $15,300,072 | $15,352,097 | $15,388,398 | $15,496,828 | $15,478,124 | $15,414,274 | $15,297,279 | $15,313,360 | $15,313,254 | $15,311,269 | $15,289,285 | $15,324,128 | $184,278,369 |
| c. Total Jurisdictional ECRC Costs | $17,199,846 | $16,940,877 | $17,338,086 | $17,698,291 | $17,230,306 | $17,437,127 | $17,209,590 | $17,546,680 | $17,258,990 | $16,561,367 | $17,100,184 | $21,645,026 | $211,166,369 |
| 5. Over/(Under) Recovery (Line 3 - Line 4c) | ($846,815) | ($2,026,063) | ($2,927,583) | ($2,458,235) | $817,913 | $1,394,785 | $2,747,337 | $3,673,764 | $4,074,821 | $1,783,557 | ($1,490,962) | ($6,722,103) | ($1,979,584) |
| 6. Interest Provision (Form 42-3A, Line 10) | ($2) | ($69) | ($192) | ($378) | ($333) | ($223) | ($155) | $17 | $237 | $407 | $491 | $296 | $96 |
| 7. Prior Periods True-Up to be (Collected)/Refunded | ($2,364,901) | ($3,014,642) | ($4,843,699) | ($7,574,398) | ($9,835,936) | ($8,821,281) | ($7,229,645) | ($4,285,388) | ($414,532) | $3,857,601 | $5,838,640 | $4,545,244 | ($2,364,901) |
| a. Deferred True-Up (Form 42-1A, Line 7) [1] | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $0 |
| 8. True-Up Collected /(Refunded) (See Line 2) | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $2,364,901 |
| 9. End of Period True-Up (Lines 5+6+7+7a+8) | ($353,079) | ($2,182,136) | ($4,912,835) | ($7,174,373) | ($6,159,718) | ($4,568,082) | ($1,623,825) | $2,247,031 | $6,519,164 | $8,500,203 | $7,206,807 | $682,075 | ($1,979,488) |
| 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) | ($353,079) | ($2,182,136) | ($4,912,835) | ($7,174,373) | ($6,159,718) | ($4,568,082) | ($1,623,825) | $2,247,031 | $6,519,164 | $8,500,203 | $7,206,807 | $682,075 | ($1,979,488) |

[1] From FPL's 2013 Final True-up filed on April 1, 2014.

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

FORM: 42-3A

JANUARY 2014 THROUGH DECEMBER 2014

| | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10) | $296,662 | ($353,079) | ($2,182,136) | ($4,912,835) | ($7,174,373) | ($6,159,718) | ($4,568,082) | ($1,623,825) | $2,247,031 | $6,519,164 | $8,500,203 | $7,206,807 | N/A |
| 2. Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8) | ($353,078) | ($2,182,067) | ($4,912,643) | ($7,173,995) | ($6,159,385) | ($4,567,859) | ($1,623,671) | $2,247,014 | $6,518,927 | $8,499,796 | $7,206,316 | $681,779 | N/A |
| 3. Total of Beginning & Ending True-Up (Lines 1 + 2) | ($56,416) | ($2,535,146) | ($7,094,779) | ($12,086,831) | ($13,333,758) | ($10,727,577) | ($6,191,753) | $623,189 | $8,765,958 | $15,018,961 | $15,706,519 | $7,888,586 | N/A |
| 4. Average True-Up Amount (Line 3 x 1/2) | ($28,208) | ($1,267,573) | ($3,547,389) | ($6,043,415) | ($6,666,879) | ($5,363,789) | ($3,095,876) | $311,594 | $4,382,979 | $7,509,480 | $7,853,260 | $3,944,293 | N/A |
| 5. Interest Rate (First Day of Reporting Month) | 0.08000% | 0.07000% | 0.06000% | 0.07000% | 0.08000% | 0.04000% | 0.06000% | 0.06000% | 0.07000% | 0.06000% | 0.07000% | 0.08000% | N/A |
| 6. Interest Rate (First Day of Subsequent Month) | 0.07000% | 0.06000% | 0.07000% | 0.08000% | 0.04000% | 0.06000% | 0.06000% | 0.07000% | 0.06000% | 0.07000% | 0.08000% | 0.10000% | N/A |
| 7. Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 0.15000% | 0.13000% | 0.13000% | 0.15000% | 0.12000% | 0.10000% | 0.12000% | 0.13000% | 0.13000% | 0.13000% | 0.15000% | 0.18000% | N/A |
| 8. Average Interest Rate (Line 7 x 1/2) | 0.07500% | 0.06500% | 0.06500% | 0.07500% | 0.06000% | 0.05000% | 0.06000% | 0.06500% | 0.06500% | 0.06500% | 0.07500% | 0.09000% | N/A |
| 9. Monthly Average Interest Rate (Line 8 x 1/12) | 0.00625% | 0.00542% | 0.00542% | 0.00625% | 0.00500% | 0.00417% | 0.00500% | 0.00542% | 0.00542% | 0.00542% | 0.00625% | 0.00750% | N/A |
| 10. Interest Provision for the Month (Line 4 x Line 9) | ($2) | ($69) | ($192) | ($378) | ($333) | ($223) | ($155) | $17 | $237 | $407 | $491 | $296 | $96 |

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

FORM: 42-4A-1

JANUARY 2014 THROUGH DECEMBER 2014

VARIANCE REPORT OF O&M ACTIVITES

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| | ECRC - 2014 Final True-Up [a] | ECRC - 2014 Actual/Estimated [b] | Dif. ECRC - 2014 Actual/Estimated [c] | % Dif. ECRC - 2014 Actual/Estimated [d] |
| 1. Description of O&M Activities | | | | |
| 1 - Air Operating Permit Fees | $79,421 | $127,300 | ($47,879) | (37.6%) |
| 3a - Continuous Emission Monitoring Systems | $662,906 | $1,013,354 | ($350,448) | (34.6%) |
| 5a - Maintenance of Stationary Above Ground Fuel Storage Tanks | $2,305,174 | $3,003,859 | ($698,685) | (23.3%) |
| 8a - Oil Spill Clean-up/Response Equipment | $221,312 | $222,085 | ($773) | (0.3%) |
| 13 - RCRA (Resource Conservation & Recovery Act) Corrective Action | $14,762 | $22,762 | ($8,000) | (35.1%) |
| 14 - NPDES Permit Fees | $80,700 | $85,576 | ($4,876) | (5.7%) |
| 17a - Disposal of Non-Containerized Liquid Waste | $1,029 | $639 | $391 | 61.2% |
| 19a - Substation Pollutant Discharge Prevention & Removal - Distribution | $1,628,676 | $2,116,482 | ($487,806) | (23.0%) |
| 19b - Substation Pollutant Discharge Prevention & Removal - Transmission | $1,710,064 | $2,440,730 | ($730,667) | (29.9%) |
| NA - Amortization of Gains on Sales of Emissions Allowances | ($389,373) | ($389,373) | ($0) | 0.0% |
| 22 - Pipeline Integrity Management | $372,163 | $492,970 | ($120,808) | (24.5%) |
| 23 - SPCC - Spill Prevention, Control & Countermeasures | $1,082,061 | $1,176,532 | ($94,471) | (8.0%) |
| 24 - Manatee Reburn | $190,088 | $327,395 | ($137,307) | (41.9%) |
| 27 - Lowest Quality Water Source | $182,626 | $180,158 | $2,468 | 1.4% |
| 28 - CWA 316(b) Phase II Rule | $188,750 | $460,745 | ($271,995) | (59.0%) |
| 29 - SCR Consumables | $504,970 | $511,642 | ($6,672) | (1.3%) |
| 30 - HBMP | $26,093 | $23,520 | $2,573 | 10.9% |
| 31 - Clean Air Interstate Rule (CAIR) Compliance | $5,025,842 | $5,082,196 | ($56,355) | (1.1%) |
| 32 - BART | $0 | $6,000 | ($6,000) | (100.0%) |
| 33 - MATS Project | $1,758,430 | $1,446,334 | $312,096 | 21.6% |
| 35 - Martin Plant Drinking Water System Compliance | $39,589 | $30,200 | $9,389 | 31.1% |
| 37 - DeSoto Next Generation Solar Energy Center | $911,750 | $941,882 | ($30,132) | (3.2%) |
| 38 - Space Coast Next Generation Solar Energy Center | $203,509 | $226,485 | ($22,976) | (10.1%) |
| 39 - Martin Next Generation Solar Energy Center | $3,817,324 | $3,888,359 | ($71,035) | (1.8%) |
| 40 - Greenhouse Gas Reduction Program | $8,865 | $28,852 | ($19,988) | (69.3%) |
| 41 - Manatee Temporary Heating System | $439,228 | $442,589 | ($3,361) | (0.8%) |
| 42 - Turkey Point Cooling Canal Monitoring Plan | $5,823,115 | $1,597,608 | $4,225,507 | 264.5% |
| 45 - 800 MW Unit ESP | $484,496 | $731,327 | ($246,831) | (33.8%) |
| 46 - St. Lucie Cooling Water Discharge Monitoring | $343,763 | $397,388 | ($53,625) | (13.5%) |
| 47 - NPDES Permit Renewal Requirements | $125,796 | $120,483 | $5,313 | 4.4% |
| 48 - Industrial Boiler MACT | $3,464 | $10,000 | ($6,536) | (65.4%) |
| 49 - Thermal Discharge Standards | $139,215 | $188,773 | ($49,557) | (26.3%) |
| 50 - Steam Electric Effluent Guidelines Revised Rules | $100,302 | $15,000 | $85,302 | 568.7% |
| 51 - Gopher Tortoise Relocations | $16,788 | $29,000 | ($12,213) | (42.1%) |
| 52 - Numeric Nutrient Criteria Water Quality Standards in Florida | $19 | $1,267 | ($1,248) | (98.5%) |
| 2. Total O&M Activities | $28,102,915 | $27,000,121 | $1,102,795 | 4.1% |

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

[b] The approved projected amount in accordance with FPSC Order No. 14-0643-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 2014 THROUGH DECEMBER 2014

VARIANCE REPORT OF O&M ACTIVITIES

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| | ECRC - 2014 Final True-Up | ECRC - 2014 Actual/Estimated | Dif. ECRC - 2014 Actual/Estimated | % Dif. ECRC - 2014 Actual/Estimated |
| 2. Total of O&M Activities | $28,102,915 | $27,000,121 | $1,102,795 | 4.1% |
| 3. Recoverable Costs Allocated to Energy | $14,941,872 | $11,335,696 | $3,606,175 | 31.8% |
| 4a. Recoverable Costs Allocated to CP Demand | $11,532,368 | $13,547,942 | ($2,015,574) | (14.9%) |
| 4b. Recoverable Costs Allocated to GCP Demand | $1,628,676 | $2,116,482 | ($487,806) | (23.0%) |
| 7. Jurisdictional Energy Recoverable Costs | $14,279,716 | $10,833,351 | $3,446,366 | 31.8% |
| 8a. Jurisdictional CP Demand Recoverable Costs | $10,979,608 | $12,898,573 | ($1,918,965) | (14.9%) |
| 8b. Jurisdictional GCP Demand Recoverable Costs | $1,628,676 | $2,116,482 | ($487,806) | (23.0%) |
| 9. Total Jurisdictional Recoverable Costs for O&M Activities | $26,888,000 | $25,848,406 | $1,039,594 | 4.0% |

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

FORM: 42-5A

JANUARY 2014 THROUGH DECEMBER 2014
O&M ACTIVITIES

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Monthly Data | | | | | | | | | | | | | Method of Classification | | |
| | 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 | Energy | CP Demand | GCP Demand |
| 1. Description of O&M Activities | | | | | | | | | | | | | | | | |
| 1 - Air Operating Permit Fees | $35,628 | $35,708 | ($117,477) | ($4,108) | $16,209 | $16,209 | $16,209 | $16,209 | $16,209 | $16,209 | $16,209 | $16,209 | $79,421 | $79,421 | | |
| 3a - Continuous Emission Monitoring Systems | $124,850 | $13,467 | $33,408 | $19,214 | $34,015 | $28,703 | $146,223 | $26,546 | $38,900 | $29,069 | $67,831 | $100,680 | $662,906 | $662,906 | | |
| 5a - Maintenance of Stationary Above Ground Fuel Storage Tanks | $24,323 | $45,384 | $331,911 | $395,797 | $239,482 | $446,295 | $512,561 | $216,603 | $76,180 | ($901) | $17,539 | $0 | $2,305,174 | | $2,305,174 | |
| 8a - Oil Spill Clean-up/Response Equipment | $8,058 | $13,451 | $16,702 | $11,860 | $11,982 | $12,772 | $19,594 | $25,039 | $22,964 | $24,533 | $4,088 | $50,269 | $221,312 | $221,312 | | |
| 13 - RCRA (Resource Conservation & Recovery Act) Corrective Action | $11,072 | $0 | $0 | $3,691 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $14,762 | | $14,762 | |
| 14 - NPDES Permit Fees | $80,700 | $0 | $0 | $0 | $0 | $4,876 | ($4,876) | $0 | $0 | $0 | $0 | $0 | $80,700 | | $80,700 | |
| 17a - Disposal of Non-Containerized Liquid Waste | $0 | $0 | $317 | $0 | $322 | $0 | $0 | $0 | $391 | $0 | $0 | $0 | $1,029 | $1,029 | | |
| 19a - Substation Pollutant Discharge Prevention & Removal - Distribution | $69,966 | $241,831 | $66,772 | $55,880 | $253,395 | $68,638 | $90,632 | $249,225 | $99,171 | $131,626 | $211,112 | $90,427 | $1,628,676 | | | $1,628,676 |
| 19b - Substation Pollutant Discharge Prevention & Removal - Transmission | $258,015 | $261,119 | $347,121 | $88,467 | $47,774 | $48,234 | $60,343 | $348,855 | $58,608 | $47,271 | $32,431 | $111,825 | $1,710,064 | $131,543 | $1,578,520 | |
| NA - Amortization of Gains on Sales of Emissions Allowances | ($32,361) | ($32,361) | ($32,361) | ($32,361) | ($32,361) | ($32,498) | ($32,512) | ($32,512) | ($32,512) | ($32,512) | ($32,512) | ($32,512) | ($389,373) | ($389,373) | | |
| 22 - Pipeline Integrity Management | $0 | $0 | $0 | $3,881 | $18,053 | $2,211 | $286 | $1,923 | $146,001 | $7,543 | $88,543 | $103,722 | $372,163 | | $372,163 | |
| 23 - SPCC - Spill Prevention, Control & Countermeasures | $64,164 | $23,976 | $72,029 | $130,658 | $129,606 | $66,184 | $76,358 | $100,520 | $305,259 | ($110,425) | $121,143 | $102,590 | $1,082,061 | | $1,082,061 | |
| 24 - Manatee Reburn | ($1,406) | $4,152 | $94,251 | $0 | $13,171 | ($2,604) | $2,658 | $11,591 | $907 | ($1,698) | $0 | $69,066 | $190,088 | $190,088 | | |
| 27 - Lowest Quality Water Source | $24,225 | $25,225 | $25,013 | $11,703 | $11,466 | $11,854 | $10,672 | $12,388 | $12,540 | $12,700 | $12,201 | $12,639 | $182,626 | | $182,626 | |
| 28 - CWA 316(b) Phase II Rule | $22,177 | $51,912 | $1,517 | $2,599 | $5,120 | $17,946 | $12,150 | $10,960 | $22,913 | $7,252 | $24,140 | $10,065 | $188,750 | | $188,750 | |
| 29 - SCR Consumables | $31,541 | $27,843 | $44,771 | $55,350 | $11,539 | $116,854 | $44,750 | $27,200 | $29,387 | $35,990 | $29,264 | $50,481 | $504,970 | $504,970 | | |
| 30 - HBMP | $2,130 | $2,130 | $2,130 | $2,130 | $2,130 | $2,130 | $2,130 | $23,875 | ($19,402) | $0 | $4,473 | $2,237 | $26,093 | | $26,093 | |
| 31 - Clean Air Interstate Rule (CAIR) Compliance | $359,174 | $388,995 | $422,818 | $946,137 | $395,822 | $128,770 | $380,313 | $459,472 | $473,679 | $338,095 | $389,217 | $343,350 | $5,025,842 | $5,025,842 | | |
| 33 - MATS Project | $89,607 | $91,994 | ($29,785) | $67,645 | $3,231 | $418,092 | $200,276 | $217,104 | $206,022 | $133,940 | $206,162 | $154,143 | $1,758,430 | $1,758,430 | | |
| 35 - Martin Plant Drinking Water System Compliance | $0 | $0 | $5,483 | $9,010 | $0 | $5,300 | $0 | $0 | $10,574 | $2,650 | $2,650 | $3,922 | $39,589 | | $39,589 | |
| 37 - DeSoto Next Generation Solar Energy Center | $91,559 | $43,580 | $68,884 | $40,508 | $121,029 | $120,936 | $65,999 | $98,364 | $57,051 | $51,258 | $81,240 | $71,343 | $911,750 | | $911,750 | |
| 38 - Space Coast Next Generation Solar Energy Center | $33,814 | $17,178 | $17,344 | $16,298 | $11,372 | $13,439 | $22,201 | $15,476 | $13,407 | $16,842 | $12,286 | $13,852 | $203,509 | | $203,509 | |
| 39 - Martin Next Generation Solar Energy Center | $382,554 | $314,813 | $328,473 | $376,039 | $281,442 | $376,500 | $251,556 | $204,836 | $132,832 | $405,179 | $264,074 | $499,024 | $3,817,324 | | $3,817,324 | |
| 40 - Greenhouse Gas Reduction Program | $4,432 | $0 | $0 | $0 | $0 | $0 | $4,432 | $0 | $0 | $0 | $0 | $0 | $8,865 | $8,865 | | |
| 41 - Manatee Temporary Heating System | $27,755 | $20,118 | $33,608 | $55,235 | $32,154 | $60,172 | $19,965 | $33,788 | $39,699 | $33,399 | $38,601 | $44,736 | $439,228 | $439,228 | | |
| 42 - Turkey Point Cooling Canal Monitoring Plan | $177,493 | $29,506 | $142,986 | $12,742 | $129,446 | $99,524 | $14,751 | $186,990 | $240,485 | $72,189 | $164,167 | $4,552,837 | $5,823,115 | $5,823,115 | | |
| 45 - 800 MW Unit ESP | ($3,131) | $22,732 | $70,154 | $17,126 | $64,539 | $41,700 | $48,268 | $42,048 | $40,178 | $40,534 | $32,033 | $68,314 | $484,496 | $484,496 | | |
| 46 - St. Lucie Cooling Water Discharge Monitoring | $96,224 | $4,053 | $56,726 | $7,745 | $8,328 | $8,734 | $7,218 | $17,926 | $14,165 | $16,025 | $74,569 | $32,049 | $343,763 | | $343,763 | |
| 47 - NPDES Permit Renewal Requirements | $3,545 | $4,399 | $6,025 | $6,430 | $1,036 | $11,514 | $22,441 | $12,322 | $21,012 | $12,552 | $10,387 | $14,131 | $125,796 | | $125,796 | |
| 48 - Industrial Boiler MACT | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $3,464 | $3,464 | | $3,464 | |
| 49 - Thermal Discharge Standards | $2,591 | $2,959 | $32,979 | $5,416 | $14,754 | $24,100 | $7,091 | $2,785 | $7,976 | $14,452 | $16,108 | $8,006 | $139,215 | | $139,215 | |
| 50 - Steam Electric Effluent Guidelines Revised Rules | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $100,302 | $100,302 | | $100,302 | |
| 51 - Gopher Tortoise Relocations | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $16,788 | $16,788 | | $16,788 | |
| 52 - Numeric Nutrient Criteria Water Quality Standards in Florida | $0 | $13 | $0 | $0 | ($13) | $1,267 | ($970) | ($278) | $0 | $0 | $0 | $0 | $19 | | $19 | |
| 2. Total of O&M Activities | $1,988,698 | $1,654,176 | $2,041,800 | $2,305,092 | $1,825,041 | $2,117,851 | $2,000,719 | $2,329,257 | $2,034,595 | $1,303,774 | $1,887,955 | $6,613,958 | $28,102,915 | $14,941,872 | $11,532,368 | $1,628,676 |

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

FORM: 42-5A

JANUARY 2014 THROUGH DECEMBER 2014

O&M ACTIVITIES

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
| 2. Total of O&M Activities | $1,988,698 | $1,654,176 | $2,041,800 | $2,305,092 | $1,825,041 | $2,117,851 | $2,000,719 | $2,329,257 | $2,034,595 | $1,303,774 | $1,887,955 | $6,613,958 | $28,102,915 |
| 3. Recoverable Costs Allocated to Energy | $841,487 | $635,691 | $706,094 | $1,155,645 | $683,743 | $891,403 | $869,568 | $1,040,310 | $1,080,817 | $693,385 | $917,554 | $5,426,174 | $14,941,872 |
| 4a. Recoverable Costs Allocated to CP Demand | $1,077,246 | $776,654 | $1,268,935 | $1,093,566 | $887,902 | $1,157,810 | $1,040,519 | $1,039,721 | $854,607 | $478,762 | $759,288 | $1,097,357 | $11,532,368 |
| 4b. Recoverable Costs Allocated to GCP Demand | $69,966 | $241,831 | $66,772 | $55,880 | $253,395 | $68,638 | $90,632 | $249,225 | $99,171 | $131,626 | $211,112 | $90,427 | $1,628,676 |
| 5. Retail Energy Jurisdictional Factor | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | |
| 6a. Retail CP Demand Jurisdictional Factor | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | |
| 6b. Retail GCP 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 Energy Recoverable Costs [a] | $804,196 | $607,520 | $674,803 | $1,104,433 | $653,443 | $851,900 | $831,033 | $994,208 | $1,032,920 | $662,657 | $876,893 | $5,185,711 | $14,279,716 |
| 8a. Jurisdictional CP Demand Recoverable Costs [b] | $1,025,612 | $739,428 | $1,208,113 | $1,041,151 | $845,344 | $1,102,315 | $990,646 | $989,886 | $813,645 | $455,815 | $722,894 | $1,044,759 | $10,979,608 |
| 8b. Jurisdictional GCP Demand Recoverable Costs [c] | $69,966 | $241,831 | $66,772 | $55,880 | $253,395 | $68,638 | $90,632 | $249,225 | $99,171 | $131,626 | $211,112 | $90,427 | $1,628,676 |
| 9. Total Jurisdictional Recoverable Costs for O&M Activities [d] | $1,899,774 | $1,588,779 | $1,949,688 | $2,201,463 | $1,752,182 | $2,022,853 | $1,912,310 | $2,233,320 | $1,945,736 | $1,250,098 | $1,810,899 | $6,320,897 | $26,888,000 |

[a] Line 3 x Line 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

FORM: 42-6A

JANUARY 2014 THROUGH DECEMBER 2014

VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| PROJECT # | ECRC - 2014 Final True-Up [a] | ECRC - 2014 Actual/Estimated [b] | Dif. ECRC - 2014 Actual/Estimated [c] | % Dif. ECRC - 2014 Actual/Estimated [d] |
| 1. Description of Investment Projects | | | | |
| 2 - Low NOX Burner Technology | $113,810 | $113,810 | $0 | N/A |
| 3b - Continuous Emission Monitoring Systems | $527,995 | $525,601 | $2,393 | 0.5% |
| 4b - Clean Closure Equivalency | $1,230 | $1,230 | $0 | N/A |
| 5b - Maintenance of Stationary Above Ground Fuel Storage Tanks | $902,157 | $963,774 | ($61,617) | (6.4%) |
| 7 - Relocate Turbine Lube Oil Underground Piping to Above Ground | $1,390 | $1,390 | $0 | 0.0% |
| 8b - Oil Spill Clean-up/Response Equipment | $139,429 | $144,255 | ($4,826) | (3.3%) |
| 10 - Relocate Storm Water Runoff | $7,758 | $7,758 | $0 | N/A |
| 12 - Scherer Discharge Pipeline | $51,367 | $51,367 | $0 | N/A |
| 20 - Wastewater Discharge Elimination & Reuse | $81,853 | $81,853 | $0 | 0.0% |
| NA - Amortization of Gains on Sales of Emissions Allowances | ($43,273) | ($43,273) | $0 | (0.0%) |
| 21 - St. Lucie Turtle Nets | $122,948 | $279,267 | ($156,319) | (56.0%) |
| 22 - Pipeline Integrity Management | $325,474 | $338,676 | ($13,202) | (3.9%) |
| 23 - SPCC - Spill Prevention, Control & Countermeasures | $1,587,011 | $1,593,917 | ($6,906) | (0.4%) |
| 24 - Manatee Reburn | $3,212,302 | $3,215,422 | ($3,120) | (0.1%) |
| 25 - Pt. Everglades ESP Technology | $19,819,988 | $19,819,988 | $1 | 0.0% |
| 26 - UST Remove/Replacement | $9,444 | $9,444 | $0 | N/A |
| 31 - Clean Air Interstate Rule (CAIR) Compliance | $59,355,524 | $59,465,721 | ($110,197) | (0.2%) |
| 33 - MATS Project | $11,876,852 | $11,876,705 | $147 | 0.0% |
| 35 - Martin Plant Drinking Water System Compliance | $24,859 | $24,859 | $0 | N/A |
| 36 - Low-Level Radioactive Waste Storage | $822,967 | $1,144,094 | ($321,127) | (28.1%) |
| 37 - DeSoto Next Generation Solar Energy Center | $16,522,827 | $16,521,288 | $1,538 | 0.0% |
| 38 - Space Coast Next Generation Solar Energy Center | $7,786,861 | $7,786,812 | $50 | 0.0% |
| 39 - Martin Next Generation Solar Energy Center | $47,896,774 | $47,909,856 | ($13,082) | (0.0%) |
| 41 - Manatee Temporary Heating System | $870,172 | $870,172 | $0 | 0.0% |
| 42 - Turkey Point Cooling Canal Monitoring Plan | $383,506 | $383,506 | $0 | N/A |
| 44 - Martin Plant Barley Barber Swamp Iron Mitigation | $18,131 | $18,131 | $0 | 0.0% |
| 45 - 800 MW Unit ESP | $21,003,163 | $20,797,426 | $205,737 | 1.0% |
| 2. Total Investment Projects - Recoverable Costs | $193,422,519 | $193,903,049 | ($480,529) | (0.2%) |

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

[b] The approved projected amount in accordance with FPSC Order No. PSC-14-0643-FOF-EI

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

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

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

FORM: 42-6A

JANUARY 2014 THROUGH DECEMBER 2014

VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| | ECRC - 2014 Final True-Up | ECRC - 2014 Actual/Estimated | Dif. ECRC - 2014 Actual/Estimated | % Dif. ECRC - 2014 Actual/Estimated |
| 2. Total Investment Projects - Recoverable Costs | $193,422,519 | $193,903,049 | ($480,529) | (0.2%) |
| 3. Recoverable Costs Allocated to Energy | $35,074,699 | $35,128,159 | ($53,460) | (0.2%) |
| 4. Recoverable Costs Allocated to Demand | $158,347,821 | $158,774,890 | ($427,069) | (0.3%) |
| 7. Jurisdictional Energy Recoverable Costs | $33,520,349 | $33,571,440 | ($51,091) | (0.2%) |
| 8. Jurisdictional Demand Recoverable Costs | $150,758,020 | $151,164,619 | ($406,599) | (0.3%) |
| 9. Total Jurisdictional Recoverable Costs for Investment Projects | $184,278,369 | $184,736,059 | ($457,690) | (0.2%) |

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

FORM: 42-7A

JANUARY 2014 THROUGH DECEMBER 2014

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Monthly Data | | | | | | | | | | | | | Method of Classification | |
| | 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 | Energy | Demand |
| 1. Description of Investment Projects [a] | | | | | | | | | | | | | | | |
| 2 - Low NOX Burner Technology | $9,748 | $9,705 | $9,663 | $9,620 | $9,577 | $9,535 | $9,432 | $9,390 | $9,348 | $9,306 | $9,264 | $9,222 | $113,810 | $113,810 | |
| 3b - Continuous Emission Monitoring Systems | $42,263 | $42,908 | $43,560 | $43,721 | $44,203 | $44,452 | $43,941 | $43,786 | $45,072 | $45,262 | $45,098 | $43,727 | $527,995 | $527,995 | |
| 4b - Clean Closure Equivalency | $105 | $104 | $104 | $104 | $103 | $103 | $102 | $102 | $101 | $101 | $101 | $100 | $1,230 | $95 | $1,135 |
| 5b - Maintenance of Stationary Above Ground Fuel Storage Tanks | $75,690 | $75,520 | $75,351 | $75,181 | $75,012 | $74,842 | $73,902 | $74,688 | $75,269 | $75,210 | $75,040 | $76,453 | $902,157 | $69,397 | $832,761 |
| 7 - Relocate Turbine Lube Oil Underground Piping to Above Ground | $119 | $118 | $118 | $117 | $117 | $116 | $115 | $115 | $114 | $114 | $113 | $113 | $1,390 | $107 | $1,283 |
| 8b - Oil Spill Clean-up/Response Equipment | $12,454 | $12,441 | $12,398 | $12,342 | $12,287 | $12,116 | $11,543 | $11,168 | $11,048 | $10,784 | $10,512 | $10,335 | $139,429 | $10,725 | $128,703 |
| 10 - Relocate Storm Water Runoff | $658 | $656 | $655 | $653 | $652 | $651 | $642 | $641 | $640 | $638 | $637 | $635 | $7,758 | $597 | $7,161 |
| 12 - Scherer Discharge Pipeline | $4,371 | $4,358 | $4,345 | $4,332 | $4,319 | $4,306 | $4,255 | $4,242 | $4,229 | $4,216 | $4,203 | $4,190 | $51,367 | $3,951 | $47,415 |
| 20 - Wastewater Discharge Elimination & Reuse | $6,932 | $6,918 | $6,905 | $6,891 | $6,878 | $6,865 | $6,777 | $6,764 | $6,750 | $6,737 | $6,724 | $6,711 | $81,853 | $6,296 | $75,556 |
| NA - Amortization of Gains on Sales of Emissions Allowances | ($5,044) | ($4,786) | ($4,528) | ($4,273) | ($4,018) | ($3,760) | ($3,450) | ($3,194) | ($2,939) | ($2,683) | ($2,427) | ($2,171) | ($43,273) | ($43,273) | |
| 21 - St. Lucie Turtle Nets | $9,598 | $9,691 | $9,823 | $9,993 | $10,140 | $10,254 | $10,273 | $10,441 | $10,593 | $10,691 | $10,702 | $10,749 | $122,948 | $9,458 | $113,491 |
| 22 - Pipeline Integrity Management | $27,504 | $27,464 | $27,424 | $27,383 | $27,343 | $27,302 | $26,942 | $26,902 | $26,862 | $26,822 | $26,783 | $26,743 | $325,474 | $25,036 | $300,438 |
| 23 - SPCC - Spill Prevention, Control & Countermeasures | $134,100 | $134,218 | $133,945 | $133,704 | $133,436 | $133,143 | $131,611 | $131,524 | $131,171 | $130,932 | $130,840 | $128,385 | $1,587,011 | $122,078 | $1,464,934 |
| 24 - Manatee Reburn | $263,911 | $265,897 | $269,290 | $271,841 | $271,801 | $271,288 | $267,837 | $267,293 | $266,748 | $266,087 | $265,426 | $264,883 | $3,212,302 | $3,212,302 | |
| 25 - Pt. Everglades ESP Technology | $1,712,323 | $1,701,671 | $1,691,019 | $1,680,367 | $1,669,716 | $1,659,064 | $1,643,884 | $1,633,385 | $1,622,887 | $1,612,389 | $1,601,891 | $1,591,393 | $19,819,988 | $19,819,988 | |
| 26 - UST Remove/Replacement | $800 | $798 | $797 | $795 | $794 | $792 | $782 | $780 | $779 | $777 | $776 | $774 | $9,444 | $726 | $8,718 |
| 31 - Clean Air Interstate Rule (CAIR) Compliance | $4,994,186 | $4,985,274 | $4,976,044 | $4,966,788 | $4,957,887 | $4,949,889 | $4,932,372 | $4,952,307 | $4,928,733 | $4,910,223 | $4,903,576 | $4,898,245 | $59,355,524 | $4,565,810 | $54,789,714 |
| 33 - MATS Project | $1,005,377 | $1,003,524 | $1,001,670 | $999,817 | $997,964 | $996,110 | $983,274 | $981,447 | $979,620 | $977,821 | $976,023 | $974,204 | $11,876,852 | $913,604 | $10,963,248 |
| 35 - Martin Plant Drinking Water System Compliance | $2,102 | $2,098 | $2,095 | $2,092 | $2,088 | $2,085 | $2,058 | $2,055 | $2,051 | $2,048 | $2,045 | $2,042 | $24,859 | $1,912 | $22,947 |
| 36 - Low-Level Radioactive Waste Storage | $69,313 | $69,313 | $69,275 | $69,194 | $69,111 | $69,036 | $68,130 | $68,041 | $67,991 | $67,943 | $67,854 | $67,765 | $822,967 | $63,305 | $759,661 |
| 37 - DeSoto Next Generation Solar Energy Center | $1,403,660 | $1,399,971 | $1,396,291 | $1,392,611 | $1,388,931 | $1,385,377 | $1,368,182 | $1,364,546 | $1,360,887 | $1,357,544 | $1,354,223 | $1,350,605 | $16,522,827 | $1,270,987 | $15,251,840 |
| 38 - Space Coast Next Generation Solar Energy Center | $661,459 | $659,758 | $658,058 | $656,357 | $654,656 | $652,955 | $644,802 | $643,122 | $641,443 | $639,763 | $638,084 | $636,404 | $7,786,861 | $598,989 | $7,187,872 |
| 39 - Martin Next Generation Solar Energy Center | $4,020,638 | $4,038,429 | $4,050,055 | $4,040,822 | $4,032,492 | $4,023,999 | $3,973,956 | $3,963,305 | $3,952,995 | $3,942,902 | $3,933,342 | $3,923,840 | $47,896,774 | $3,684,367 | $44,212,407 |
| 41 - Manatee Temporary Heating System | $103,861 | $103,134 | $102,406 | $212,619 | $44,594 | $44,311 | $43,904 | $43,626 | $43,347 | $43,069 | $42,791 | $42,512 | $870,172 | $66,936 | $803,236 |
| 42 - Turkey Point Cooling Canal Monitoring Plan | $32,387 | $32,344 | $32,301 | $32,258 | $32,215 | $32,172 | $31,744 | $31,702 | $31,659 | $31,617 | $31,575 | $31,532 | $383,506 | $29,500 | $354,006 |
| 44 - Martin Plant Barley Barber Swamp Iron Mitigation | $1,532 | $1,530 | $1,528 | $1,525 | $1,523 | $1,521 | $1,501 | $1,499 | $1,496 | $1,494 | $1,492 | $1,490 | $18,131 | | $18,131 |
| 45 - 800 MW Unit ESP | $1,468,943 | $1,530,604 | $1,581,226 | $1,618,853 | $1,802,338 | $1,770,615 | $1,777,851 | $1,803,616 | $1,854,334 | $1,899,388 | $1,911,469 | $1,983,926 | $21,003,163 | | $21,003,163 |
| 2. Total Investment Projects - Recoverable Costs | $16,058,988 | $16,113,662 | $16,151,816 | $16,265,710 | $16,246,158 | $16,179,142 | $16,056,362 | $16,073,293 | $16,073,230 | $16,071,197 | $16,048,155 | $16,084,806 | $193,422,519 | $35,074,699 | $158,347,821 |

[a] Each project's Total System Recoverable Expenses 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 2014 THROUGH DECEMBER 2014

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
| 2. Total Investment Projects - Recoverable Costs | $16,058,988 | $16,113,662 | $16,151,816 | $16,265,710 | $16,246,158 | $16,179,142 | $16,056,362 | $16,073,293 | $16,073,230 | $16,071,197 | $16,048,155 | $16,084,806 | $193,422,519 |
| 3. Recoverable Costs Allocated to Energy | $2,989,762 | $2,982,021 | $2,975,162 | $2,973,896 | $2,949,050 | $2,936,459 | $2,908,979 | $2,898,162 | $2,885,445 | $2,871,896 | $2,858,940 | $2,844,926 | $35,074,699 |
| 4. Recoverable Costs Allocated to Demand | $13,069,226 | $13,131,642 | $13,176,654 | $13,291,814 | $13,297,109 | $13,242,684 | $13,147,382 | $13,175,131 | $13,187,785 | $13,199,300 | $13,189,214 | $13,239,880 | $158,347,821 |
| 5. Retail Energy Jurisdictional Factor | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | |
| 6. Retail Demand Jurisdictional Factor | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | |
| 7. Jurisdictional Energy Recoverable Costs [a] | $2,857,270 | $2,849,871 | $2,843,317 | $2,842,107 | $2,818,361 | $2,806,328 | $2,780,067 | $2,769,729 | $2,757,576 | $2,744,627 | $2,732,245 | $2,718,852 | $33,520,349 |
| 8. Jurisdictional Demand Recoverable Costs [b] | $12,442,802 | $12,502,226 | $12,545,081 | $12,654,721 | $12,659,762 | $12,607,946 | $12,517,213 | $12,543,632 | $12,555,679 | $12,566,642 | $12,557,039 | $12,605,276 | $150,758,020 |
| 9. Total Jurisdictional Recoverable Costs for Investment Projects | $15,300,072 | $15,352,097 | $15,388,398 | $15,496,828 | $15,478,124 | $15,414,274 | $15,297,279 | $15,313,360 | $15,313,254 | $15,311,269 | $15,289,285 | $15,324,128 | $184,278,369 |

[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 2014 THROUGH DECEMBER 2014

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2 - Low NOX Burner Technology** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | N/A |
| 3. Less: Accumulated Depreciation | $2,008,646 | $2,013,987 | $2,019,327 | $2,024,668 | $2,030,008 | $2,035,348 | $2,040,689 | $2,046,029 | $2,051,369 | $2,056,710 | $2,062,050 | $2,067,390 | $2,072,731 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $554,730 | $549,390 | $544,049 | $538,709 | $533,368 | $528,028 | $522,688 | $517,347 | $512,007 | $506,667 | $501,326 | $495,986 | $490,646 | N/A |
| 6. Average Net Investment | | $552,060 | $546,719 | $541,379 | $536,039 | $530,698 | $525,358 | $520,018 | $514,677 | $509,337 | $503,997 | $498,656 | $493,316 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $3,687 | $3,651 | $3,616 | $3,580 | $3,544 | $3,509 | $3,453 | $3,417 | $3,382 | $3,346 | $3,311 | $3,275 | $41,771 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $720 | $713 | $706 | $699 | $692 | $685 | $639 | $633 | $626 | $620 | $613 | $606 | $7,955 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $64,084 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $9,748 | $9,705 | $9,663 | $9,620 | $9,577 | $9,535 | $9,432 | $9,390 | $9,348 | $9,306 | $9,264 | $9,222 | $113,810 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

JANUARY 2014 THROUGH DECEMBER 2014

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **3b - Continuous Emission Monitoring Systems** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $71,150 | $0 | $50,086 | $69,306 | $48 | ($1) | $0 | $82,917 | $0 | $0 | ($823,697) | ($550,191) |
| c. Retirements | | $0 | $0 | $0 | ($10,185) | ($11,201) | $0 | $0 | $0 | $0 | $0 | $0 | ($823,697) | ($845,083) |
| d. Other | | ($696) | ($23) | ($3,351) | ($2,068) | ($1,077) | ($2) | ($1) | $0 | $3,590 | $0 | $0 | $0 | ($3,629) |
| 2. Plant-In-Service/Depreciation Base [a] | $6,709,643 | $6,709,643 | $6,780,793 | $6,780,793 | $6,830,880 | $6,900,186 | $6,900,234 | $6,900,233 | $6,900,233 | $6,983,149 | $6,983,149 | $6,983,149 | $6,159,452 | N/A |
| 3. Less: Accumulated Depreciation | $3,714,599 | $3,732,325 | $3,751,232 | $3,767,319 | $3,774,557 | $3,781,834 | $3,801,466 | $3,821,100 | $3,840,735 | $3,865,092 | $3,885,901 | $3,906,710 | $3,102,610 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $2,995,044 | $2,977,318 | $3,029,561 | $3,013,475 | $3,056,323 | $3,118,352 | $3,098,768 | $3,079,133 | $3,059,498 | $3,118,057 | $3,097,248 | $3,076,439 | $3,056,842 | N/A |
| 6. Average Net Investment | | $2,986,181 | $3,003,440 | $3,021,518 | $3,034,899 | $3,087,337 | $3,108,560 | $3,088,950 | $3,069,315 | $3,088,778 | $3,107,653 | $3,086,844 | $3,066,641 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $19,944 | $20,060 | $20,180 | $20,270 | $20,620 | $20,762 | $20,509 | $20,378 | $20,507 | $20,633 | $20,495 | $20,360 | $244,717 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $3,896 | $3,919 | $3,942 | $3,960 | $4,028 | $4,056 | $3,797 | $3,773 | $3,797 | $3,820 | $3,795 | $3,770 | $46,554 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $18,422 | $18,930 | $19,438 | $19,492 | $19,555 | $19,635 | $19,635 | $19,635 | $20,767 | $20,809 | $20,809 | $19,597 | $236,723 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $42,263 | $42,908 | $43,560 | $43,721 | $44,203 | $44,452 | $43,941 | $43,786 | $45,072 | $45,262 | $45,098 | $43,727 | $527,995 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

JANUARY 2014 THROUGH DECEMBER 2014

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **4b - Clean Closure Equivalency** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | N/A |
| 3. Less: Accumulated Depreciation | $13,450 | $13,488 | $13,526 | $13,564 | $13,603 | $13,641 | $13,679 | $13,717 | $13,755 | $13,793 | $13,831 | $13,870 | $13,908 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $8,349 | $8,311 | $8,273 | $8,235 | $8,197 | $8,159 | $8,120 | $8,082 | $8,044 | $8,006 | $7,968 | $7,930 | $7,892 | N/A |
| 6. Average Net Investment | | $8,330 | $8,292 | $8,254 | $8,216 | $8,178 | $8,139 | $8,101 | $8,063 | $8,025 | $7,987 | $7,949 | $7,911 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $56 | $55 | $55 | $55 | $55 | $54 | $54 | $54 | $53 | $53 | $53 | $53 | $649 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $11 | $11 | $11 | $11 | $11 | $11 | $10 | $10 | $10 | $10 | $10 | $10 | $124 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $458 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $105 | $104 | $104 | $104 | $103 | $103 | $102 | $102 | $101 | $101 | $101 | $100 | $1,230 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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JANUARY 2014 THROUGH DECEMBER 2014

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **5b - Maintenance of Stationary Above Ground Fuel Storage Tanks** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $170,156 | $18,616 | $0 | $0 | ($298,370) | ($109,598) |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($749,026) | ($749,026) |
| d. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $3,421 | $0 | $0 | $0 | $0 | $3,421 |
| 2. Plant-In-Service/Depreciation Base [a] | $10,164,793 | $10,164,793 | $10,164,793 | $10,164,793 | $10,164,793 | $10,164,793 | $10,164,793 | $10,164,793 | $10,334,949 | $10,353,565 | $10,353,565 | $10,353,565 | $10,055,195 | N/A |
| 3. Less: Accumulated Depreciation | $3,333,253 | $3,354,487 | $3,375,720 | $3,396,954 | $3,418,188 | $3,439,422 | $3,460,655 | $3,481,889 | $3,506,842 | $3,528,394 | $3,549,985 | $3,571,575 | $2,843,948 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $6,831,540 | $6,810,306 | $6,789,073 | $6,767,839 | $6,746,605 | $6,725,372 | $6,704,138 | $6,682,904 | $6,828,108 | $6,825,171 | $6,803,581 | $6,781,990 | $7,211,247 | N/A |
| 6. Average Net Investment | | $6,820,923 | $6,799,689 | $6,778,456 | $6,757,222 | $6,735,988 | $6,714,755 | $6,693,521 | $6,755,506 | $6,826,639 | $6,814,376 | $6,792,785 | $6,996,619 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $45,556 | $45,414 | $45,272 | $45,131 | $44,989 | $44,847 | $44,440 | $44,852 | $45,324 | $45,243 | $45,099 | $46,453 | $542,621 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $8,900 | $8,872 | $8,845 | $8,817 | $8,789 | $8,761 | $8,228 | $8,305 | $8,392 | $8,377 | $8,350 | $8,601 | $103,237 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $21,234 | $21,234 | $21,234 | $21,234 | $21,234 | $21,234 | $21,234 | $21,531 | $21,552 | $21,590 | $21,590 | $21,399 | $256,299 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $75,690 | $75,520 | $75,351 | $75,181 | $75,012 | $74,842 | $73,902 | $74,688 | $75,269 | $75,210 | $75,040 | $76,453 | $902,157 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **7 - Relocate Turbine Lube Oil Underground Piping to Above Ground** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $23,878 | $23,940 | $24,002 | $24,064 | $24,126 | $24,188 | $24,250 | $24,312 | $24,374 | $24,436 | $24,498 | $24,560 | $24,622 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $7,152 | $7,090 | $7,028 | $6,966 | $6,904 | $6,842 | $6,780 | $6,718 | $6,656 | $6,594 | $6,532 | $6,470 | $6,408 | N/A |
| 6. Average Net Investment | | $7,121 | $7,059 | $6,997 | $6,935 | $6,873 | $6,811 | $6,749 | $6,687 | $6,625 | $6,563 | $6,501 | $6,439 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $48 | $47 | $47 | $46 | $46 | $45 | $45 | $44 | $44 | $44 | $43 | $43 | $542 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $9 | $9 | $9 | $9 | $9 | $9 | $8 | $8 | $8 | $8 | $8 | $8 | $103 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $745 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $119 | $118 | $118 | $117 | $117 | $116 | $115 | $115 | $114 | $114 | $113 | $113 | $1,390 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **8b - Oil Spill Clean-up/Response Equipment** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $3,054 | ($2,640) | ($200) | $0 | $0 | ($14,017) | ($48,403) | $0 | ($12,254) | ($13,184) | ($14,317) | $2,883 | ($99,077) |
| c. Retirements | | ($3,872) | $0 | $0 | $0 | $0 | ($14,017) | ($48,403) | $0 | ($13,508) | ($13,184) | ($14,317) | ($13,152) | ($120,452) |
| d. Other | | $29 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $149 | $0 | $0 | $0 | $178 |
| 2. Plant-In-Service/Depreciation Base [a] | $880,172 | $883,226 | $880,586 | $880,386 | $880,386 | $880,386 | $866,370 | $817,967 | $817,967 | $805,713 | $792,529 | $778,212 | $781,095 | N/A |
| 3. Less: Accumulated Depreciation | $172,829 | $175,793 | $182,624 | $189,479 | $196,331 | $203,184 | $195,904 | $153,794 | $159,759 | $152,288 | $144,769 | $135,888 | $127,974 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $707,343 | $707,433 | $697,962 | $690,908 | $684,055 | $677,202 | $670,466 | $664,173 | $658,208 | $653,425 | $647,760 | $642,324 | $653,120 | N/A |
| 6. Average Net Investment | | $707,388 | $702,697 | $694,435 | $687,481 | $680,628 | $673,834 | $667,319 | $661,191 | $655,816 | $650,592 | $645,042 | $647,722 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $4,725 | $4,693 | $4,638 | $4,592 | $4,546 | $4,500 | $4,431 | $4,390 | $4,354 | $4,319 | $4,283 | $4,300 | $53,771 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $923 | $917 | $906 | $897 | $888 | $879 | $820 | $813 | $806 | $800 | $793 | $796 | $10,239 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $6,807 | $6,831 | $6,854 | $6,853 | $6,853 | $6,736 | $6,292 | $5,965 | $5,888 | $5,665 | $5,436 | $5,238 | $75,419 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $12,454 | $12,441 | $12,398 | $12,342 | $12,287 | $12,116 | $11,543 | $11,168 | $11,048 | $10,784 | $10,512 | $10,335 | $139,429 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **10 - Relocate Storm Water Runoff** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $57,466 | $57,643 | $57,820 | $57,997 | $58,173 | $58,350 | $58,527 | $58,703 | $58,880 | $59,057 | $59,233 | $59,410 | $59,587 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $60,327 | $60,151 | $59,974 | $59,797 | $59,621 | $59,444 | $59,267 | $59,091 | $58,914 | $58,737 | $58,560 | $58,384 | $58,207 | N/A |
| 6. Average Net Investment | | $60,239 | $60,062 | $59,886 | $59,709 | $59,532 | $59,356 | $59,179 | $59,002 | $58,826 | $58,649 | $58,472 | $58,295 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $402 | $401 | $400 | $399 | $398 | $396 | $393 | $392 | $391 | $389 | $388 | $387 | $4,736 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $79 | $78 | $78 | $78 | $78 | $77 | $73 | $73 | $72 | $72 | $72 | $72 | $901 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $2,120 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $658 | $656 | $655 | $653 | $652 | $651 | $642 | $641 | $640 | $638 | $637 | $635 | $7,758 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

JANUARY 2014 THROUGH DECEMBER 2014

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **12 - Scherer Discharge Pipeline** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $510,452 | $512,084 | $513,716 | $515,349 | $516,981 | $518,613 | $520,246 | $521,878 | $523,510 | $525,143 | $526,775 | $528,407 | $530,040 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $343,872 | $342,240 | $340,607 | $338,975 | $337,343 | $335,710 | $334,078 | $332,446 | $330,813 | $329,181 | $327,549 | $325,916 | $324,284 | N/A |
| 6. Average Net Investment | | $343,056 | $341,423 | $339,791 | $338,159 | $336,526 | $334,894 | $333,262 | $331,629 | $329,997 | $328,365 | $326,732 | $325,100 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $2,291 | $2,280 | $2,269 | $2,259 | $2,248 | $2,237 | $2,213 | $2,202 | $2,191 | $2,180 | $2,169 | $2,158 | $26,697 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $448 | $445 | $443 | $441 | $439 | $437 | $410 | $408 | $406 | $404 | $402 | $400 | $5,082 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $19,588 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $4,371 | $4,358 | $4,345 | $4,332 | $4,319 | $4,306 | $4,255 | $4,242 | $4,229 | $4,216 | $4,203 | $4,190 | $51,367 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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FORM: 42-8A

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **20 - Wastewater Discharge Elimination & Reuse** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $111,923 | $113,595 | $115,267 | $116,938 | $118,610 | $120,282 | $121,954 | $123,625 | $125,297 | $126,969 | $128,641 | $130,312 | $131,984 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $659,654 | $657,982 | $656,310 | $654,638 | $652,967 | $651,295 | $649,623 | $647,951 | $646,280 | $644,608 | $642,936 | $641,264 | $639,593 | N/A |
| 6. Average Net Investment | | $658,818 | $657,146 | $655,474 | $653,803 | $652,131 | $650,459 | $648,787 | $647,116 | $645,444 | $643,772 | $642,100 | $640,429 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $4,400 | $4,389 | $4,378 | $4,367 | $4,356 | $4,344 | $4,308 | $4,296 | $4,285 | $4,274 | $4,263 | $4,252 | $51,912 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $860 | $857 | $855 | $853 | $851 | $849 | $798 | $795 | $793 | $791 | $789 | $787 | $9,880 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $20,061 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $6,932 | $6,918 | $6,905 | $6,891 | $6,878 | $6,865 | $6,777 | $6,764 | $6,750 | $6,737 | $6,724 | $6,711 | $81,853 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **21 - St. Lucie Turtle Nets** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| d. Other | | ($9,116) | ($15,197) | ($18,964) | ($24,672) | ($13,119) | ($16,587) | ($24,953) | ($18,775) | ($20,841) | ($5,064) | $1,108 | ($14,098) | ($180,279) |
| 2. Plant-In-Service/Depreciation Base [a] | $352,942 | $352,942 | $352,942 | $352,942 | $352,942 | $352,942 | $352,942 | $352,942 | $352,942 | $352,942 | $352,942 | $352,942 | $352,942 | N/A |
| 3. Less: Accumulated Depreciation | ($778,687) | ($787,274) | ($801,942) | ($820,376) | ($844,518) | ($857,108) | ($873,166) | ($897,589) | ($915,835) | ($936,147) | ($940,681) | ($939,044) | ($952,613) | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $1,131,629 | $1,140,216 | $1,154,884 | $1,173,318 | $1,197,461 | $1,210,051 | $1,226,108 | $1,250,532 | $1,268,778 | $1,289,089 | $1,293,624 | $1,291,987 | $1,305,555 | N/A |
| 6. Average Net Investment | | $1,135,923 | $1,147,550 | $1,164,101 | $1,185,390 | $1,203,756 | $1,218,079 | $1,238,320 | $1,259,655 | $1,278,934 | $1,291,357 | $1,292,805 | $1,298,771 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $7,587 | $7,664 | $7,775 | $7,917 | $8,040 | $8,135 | $8,222 | $8,363 | $8,491 | $8,574 | $8,583 | $8,623 | $97,974 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $1,482 | $1,497 | $1,519 | $1,547 | $1,571 | $1,589 | $1,522 | $1,548 | $1,572 | $1,587 | $1,589 | $1,597 | $18,621 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $529 | $529 | $529 | $529 | $529 | $529 | $529 | $529 | $529 | $529 | $529 | $529 | $6,353 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $9,598 | $9,691 | $9,823 | $9,993 | $10,140 | $10,254 | $10,273 | $10,441 | $10,593 | $10,691 | $10,702 | $10,749 | $122,948 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **22 - Pipeline Integrity Management** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | N/A |
| 3. Less: Accumulated Depreciation | $78,373 | $83,434 | $88,495 | $93,556 | $98,617 | $103,678 | $108,740 | $113,801 | $118,862 | $123,923 | $128,984 | $134,045 | $139,106 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $2,813,674 | $2,808,613 | $2,803,552 | $2,798,491 | $2,793,430 | $2,788,369 | $2,783,308 | $2,778,247 | $2,773,186 | $2,768,125 | $2,763,064 | $2,758,003 | $2,752,941 | N/A |
| 6. Average Net Investment | | $2,811,144 | $2,806,083 | $2,801,022 | $2,795,961 | $2,790,900 | $2,785,838 | $2,780,777 | $2,775,716 | $2,770,655 | $2,765,594 | $2,760,533 | $2,755,472 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $18,775 | $18,741 | $18,708 | $18,674 | $18,640 | $18,606 | $18,462 | $18,429 | $18,395 | $18,362 | $18,328 | $18,294 | $222,415 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $3,668 | $3,661 | $3,655 | $3,648 | $3,642 | $3,635 | $3,418 | $3,412 | $3,406 | $3,400 | $3,394 | $3,387 | $42,326 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $5,061 | $5,061 | $5,061 | $5,061 | $5,061 | $5,061 | $5,061 | $5,061 | $5,061 | $5,061 | $5,061 | $5,061 | $60,733 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $27,504 | $27,464 | $27,424 | $27,383 | $27,343 | $27,302 | $26,942 | $26,902 | $26,862 | $26,822 | $26,783 | $26,743 | $325,474 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

JANUARY 2014 THROUGH DECEMBER 2014

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **23 - SPCC - Spill Prevention, Control & Countermeasures** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $93,273 | $0 | $0 | $15,988 | $0 | ($16,495) | $23,746 | $0 | ($17,625) | $21,246 | $18,142 | ($1,928,366) | ($1,790,092) |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | ($15,336) | ($8,791) | $0 | $0 | $0 | $0 | ($1,940,193) | ($1,964,320) |
| d. Other | | $1,653 | $0 | $0 | $14,733 | $0 | $0 | ($9,504) | $0 | $0 | $807 | $1,536 | $0 | $9,226 |
| 2. Plant-In-Service/Depreciation Base [a] | $16,208,033 | $16,301,307 | $16,301,307 | $16,301,307 | $16,317,294 | $16,317,294 | $16,300,799 | $16,324,545 | $16,324,545 | $16,306,920 | $16,328,165 | $16,346,307 | $14,417,942 | N/A |
| 3. Less: Accumulated Depreciation | $3,726,733 | $3,762,611 | $3,796,861 | $3,831,111 | $3,880,122 | $3,914,401 | $3,933,329 | $3,949,300 | $3,983,583 | $4,017,852 | $4,052,949 | $4,088,805 | $2,180,627 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $12,481,301 | $12,538,696 | $12,504,446 | $12,470,196 | $12,437,172 | $12,402,894 | $12,367,470 | $12,375,245 | $12,340,962 | $12,289,067 | $12,275,217 | $12,257,502 | $12,237,315 | N/A |
| 6. Average Net Investment | | $12,509,998 | $12,521,571 | $12,487,321 | $12,453,684 | $12,420,033 | $12,385,182 | $12,371,358 | $12,358,103 | $12,315,014 | $12,282,142 | $12,266,359 | $12,247,408 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $83,553 | $83,630 | $83,401 | $83,177 | $82,952 | $82,719 | $82,137 | $82,049 | $81,763 | $81,545 | $81,440 | $81,314 | $989,681 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $16,323 | $16,338 | $16,293 | $16,250 | $16,206 | $16,160 | $15,208 | $15,192 | $15,139 | $15,098 | $15,079 | $15,056 | $188,342 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $34,225 | $34,250 | $34,250 | $34,278 | $34,279 | $34,264 | $34,266 | $34,283 | $34,269 | $34,289 | $34,321 | $32,014 | $408,988 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $134,100 | $134,218 | $133,945 | $133,704 | $133,436 | $133,143 | $131,611 | $131,524 | $131,171 | $130,932 | $130,840 | $128,385 | $1,587,011 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **24 - Manatee Reburn** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $300,886 | $223,292 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $445 | $524,623 |
| b. Clearings to Plant | | $0 | $0 | $824,981 | $68,337 | $6,334 | $243 | $322 | $75 | $106 | ($106,791) | $0 | $0 | $793,608 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| d. Other | | ($3,622) | ($104,717) | ($135,185) | ($32,095) | ($1,992) | ($117) | ($155) | ($36) | ($51) | ($106,919) | ($0) | $0 | ($384,888) |
| 2. Plant-In-Service/Depreciation Base [a] | $31,170,571 | $31,170,571 | $31,170,571 | $31,995,552 | $32,063,889 | $32,070,223 | $32,070,467 | $32,070,789 | $32,070,864 | $32,070,970 | $31,964,179 | $31,964,179 | $31,964,179 | N/A |
| 3. Less: Accumulated Depreciation | $6,693,983 | $6,757,897 | $6,720,716 | $6,653,962 | $6,691,265 | $6,758,751 | $6,828,120 | $6,897,451 | $6,966,902 | $7,036,338 | $6,998,790 | $7,068,046 | $7,137,302 | N/A |
| 4. CWIP - Non Interest Bearing (h) | $1,934 | $302,820 | $526,112 | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | $445 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $24,478,522 | $24,715,494 | $24,975,966 | $25,341,590 | $25,372,624 | $25,311,472 | $25,242,347 | $25,173,338 | $25,103,962 | $25,034,632 | $24,965,388 | $24,896,133 | $24,827,322 | N/A |
| 6. Average Net Investment | | $24,597,008 | $24,845,730 | $25,158,778 | $25,357,107 | $25,342,048 | $25,276,909 | $25,207,842 | $25,138,650 | $25,069,297 | $25,000,010 | $24,930,761 | $24,861,728 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $164,280 | $165,942 | $168,032 | $169,357 | $169,256 | $168,821 | $167,363 | $166,903 | $166,443 | $165,983 | $165,523 | $165,065 | $2,002,969 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $32,094 | $32,419 | $32,827 | $33,086 | $33,066 | $32,981 | $30,988 | $30,903 | $30,818 | $30,733 | $30,647 | $30,563 | $381,125 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $67,536 | $67,536 | $68,430 | $69,398 | $69,479 | $69,486 | $69,486 | $69,487 | $69,487 | $69,371 | $69,256 | $69,256 | $828,208 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $263,911 | $265,897 | $269,290 | $271,841 | $271,801 | $271,288 | $267,837 | $267,293 | $266,748 | $266,087 | $265,426 | $264,883 | $3,212,302 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

[h] In the 2013 final true-up capital schedule, expenditures and additions amounts on Line 1 and CWIP non-interest bearing amounts on Line 4 were inadvertently excluded, however, these amounts were included in the total system recoverable expenses.

The beginning balance of $1934 on this schedule is correctly reflected.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **25 - Pt. Everglades ESP Technology** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| d. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2. Plant-In-Service/Depreciation Base [a] | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 3. Less: Accumulated Depreciation | ($48,030,721) | ($46,696,534) | ($45,362,348) | ($44,028,161) | ($42,693,974) | ($41,359,788) | ($40,025,601) | ($38,691,414) | ($37,357,228) | ($36,023,041) | ($34,688,855) | ($33,354,668) | ($32,020,481) | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $48,030,721 | $46,696,534 | $45,362,348 | $44,028,161 | $42,693,974 | $41,359,788 | $40,025,601 | $38,691,414 | $37,357,228 | $36,023,041 | $34,688,855 | $33,354,668 | $32,020,481 | N/A |
| 6. Average Net Investment | | $47,363,628 | $46,029,441 | $44,695,254 | $43,361,068 | $42,026,881 | $40,692,694 | $39,358,508 | $38,024,321 | $36,690,134 | $35,355,948 | $34,021,761 | $32,687,575 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $316,336 | $307,425 | $298,514 | $289,603 | $280,692 | $271,781 | $261,314 | $252,455 | $243,597 | $234,739 | $225,881 | $217,023 | $3,199,362 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $61,800 | $60,059 | $58,318 | $56,578 | $54,837 | $53,096 | $48,383 | $46,743 | $45,103 | $43,463 | $41,823 | $40,183 | $610,386 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $16,010,240 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $1,712,323 | $1,701,671 | $1,691,019 | $1,680,367 | $1,669,716 | $1,659,064 | $1,643,884 | $1,633,385 | $1,622,887 | $1,612,389 | $1,601,891 | $1,591,393 | $19,819,988 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **26 - UST Remove/Replacement** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $40,435 | $40,637 | $40,839 | $41,041 | $41,243 | $41,445 | $41,647 | $41,849 | $42,051 | $42,253 | $42,455 | $42,657 | $42,859 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $75,012 | $74,810 | $74,608 | $74,406 | $74,204 | $74,002 | $73,800 | $73,598 | $73,396 | $73,194 | $72,992 | $72,790 | $72,588 | N/A |
| 6. Average Net Investment | | $74,911 | $74,709 | $74,507 | $74,305 | $74,103 | $73,901 | $73,699 | $73,497 | $73,295 | $73,093 | $72,891 | $72,689 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $500 | $499 | $498 | $496 | $495 | $494 | $489 | $488 | $487 | $485 | $484 | $483 | $5,897 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $98 | $97 | $97 | $97 | $97 | $96 | $91 | $90 | $90 | $90 | $90 | $89 | $1,122 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $2,424 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $800 | $798 | $797 | $795 | $794 | $792 | $782 | $780 | $779 | $777 | $776 | $774 | $9,444 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

JANUARY 2014 THROUGH DECEMBER 2014

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **31 - Clean Air Interstate Rule (CAIR) Compliance** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $27 | $5,708 | $0 | $0 | $2,626 | $0 | $1,441,901 | $0 | $0 | $0 | $0 | $1,709 | $1,451,971 |
| b. Clearings to Plant | | $0 | $0 | ($294,998) | $0 | $19,496 | ($104,404) | $6,948,655 | $380,687 | $334,867 | $264,489 | $136,247 | $1,676,477 | $9,361,518 |
| c. Retirements | | $0 | $0 | ($294,998) | $0 | $0 | ($112,957) | $0 | $0 | ($23,596) | $0 | $0 | $0 | ($431,551) |
| d. Other | | ($7) | ($1,409) | $0 | $0 | $18,848 | ($254,413) | $261,186 | $0 | $0 | ($1,566) | $0 | ($422) | $22,218 |
| 2. Plant-In-Service/Depreciation Base [a] | $516,151,440 | $516,151,440 | $516,151,440 | $515,856,442 | $515,856,442 | $515,875,939 | $515,771,534 | $522,720,190 | $523,100,877 | $523,435,744 | $523,700,233 | $523,836,480 | $525,512,958 | N/A |
| 3. Less: Accumulated Depreciation | $30,305,558 | $31,425,371 | $32,543,781 | $33,368,283 | $34,487,464 | $35,625,513 | $36,377,252 | $37,771,114 | $38,899,137 | $39,985,889 | $41,082,392 | $42,180,873 | $43,280,785 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $27 | $5,735 | $5,735 | $5,735 | $8,362 | $0 | $1,441,901 | $1,441,901 | $1,441,901 | $1,441,901 | $1,441,901 | $1,709 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $485,845,882 | $484,726,096 | $483,613,394 | $482,493,894 | $481,374,714 | $480,258,787 | $479,394,282 | $486,390,977 | $485,643,641 | $484,891,756 | $484,059,742 | $483,097,508 | $482,233,882 | N/A |
| 6. Average Net Investment | | $485,285,989 | $484,169,745 | $483,053,644 | $481,934,304 | $480,816,751 | $479,826,535 | $482,892,630 | $486,017,309 | $485,267,698 | $484,475,749 | $483,578,625 | $482,665,695 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $3,241,165 | $3,233,710 | $3,226,256 | $3,218,780 | $3,211,316 | $3,204,702 | $3,206,077 | $3,226,823 | $3,221,846 | $3,216,588 | $3,210,631 | $3,204,570 | $38,622,463 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $633,201 | $631,745 | $630,288 | $628,828 | $627,370 | $626,078 | $593,620 | $597,461 | $596,540 | $595,566 | $594,463 | $593,341 | $7,348,500 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,119,819 | $1,119,819 | $1,119,500 | $1,119,180 | $1,119,201 | $1,119,109 | $1,132,675 | $1,128,023 | $1,110,348 | $1,098,069 | $1,098,481 | $1,100,334 | $13,384,560 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $4,994,186 | $4,985,274 | $4,976,044 | $4,966,788 | $4,957,887 | $4,949,889 | $4,932,372 | $4,952,307 | $4,928,733 | $4,910,223 | $4,903,576 | $4,898,245 | $59,355,524 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

JANUARY 2014 THROUGH DECEMBER 2014

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **33 - MATS Project** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $6,980 | $317 | $1,621 | $8,917 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $107,184,439 | $107,184,439 | $107,184,439 | $107,184,439 | $107,184,439 | $107,184,439 | $107,184,439 | $107,184,439 | $107,184,439 | $107,184,439 | $107,184,439 | $107,184,439 | $107,184,439 | N/A |
| 3. Less: Accumulated Depreciation | $10,215,983 | $10,448,122 | $10,680,261 | $10,912,400 | $11,144,539 | $11,376,678 | $11,608,817 | $11,840,955 | $12,073,094 | $12,305,233 | $12,537,372 | $12,769,511 | $13,001,650 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $6,980 | $7,297 | $8,918 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $96,968,457 | $96,736,318 | $96,504,179 | $96,272,040 | $96,039,901 | $95,807,762 | $95,575,623 | $95,343,484 | $95,111,345 | $94,879,206 | $94,654,047 | $94,422,225 | $94,191,707 | N/A |
| 6. Average Net Investment | | $96,852,387 | $96,620,248 | $96,388,109 | $96,155,970 | $95,923,831 | $95,691,692 | $95,459,553 | $95,227,414 | $94,995,275 | $94,766,627 | $94,538,136 | $94,306,966 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $646,865 | $645,315 | $643,764 | $642,214 | $640,663 | $639,113 | $633,786 | $632,245 | $630,704 | $629,186 | $627,669 | $626,134 | $7,637,657 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $126,373 | $126,070 | $125,767 | $125,464 | $125,161 | $124,859 | $117,348 | $117,063 | $116,778 | $116,497 | $116,216 | $115,932 | $1,453,528 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $232,139 | $232,139 | $232,139 | $232,139 | $232,139 | $232,139 | $232,139 | $232,139 | $232,139 | $232,139 | $232,139 | $232,139 | $2,785,667 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $1,005,377 | $1,003,524 | $1,001,670 | $999,817 | $997,964 | $996,110 | $983,274 | $981,447 | $979,620 | $977,821 | $976,023 | $974,204 | $11,876,852 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **35 - Martin Plant Drinking Water System Compliance** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $23,540 | $23,952 | $24,364 | $24,776 | $25,188 | $25,600 | $26,012 | $26,424 | $26,836 | $27,248 | $27,660 | $28,071 | $28,483 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $211,851 | $211,439 | $211,027 | $210,615 | $210,203 | $209,791 | $209,380 | $208,968 | $208,556 | $208,144 | $207,732 | $207,320 | $206,908 | N/A |
| 6. Average Net Investment | | $211,645 | $211,233 | $210,821 | $210,409 | $209,997 | $209,586 | $209,174 | $208,762 | $208,350 | $207,938 | $207,526 | $207,114 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $1,414 | $1,411 | $1,408 | $1,405 | $1,403 | $1,400 | $1,389 | $1,386 | $1,383 | $1,381 | $1,378 | $1,375 | $16,732 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $276 | $276 | $275 | $275 | $274 | $273 | $257 | $257 | $256 | $256 | $255 | $255 | $3,184 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $4,943 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $2,102 | $2,098 | $2,095 | $2,092 | $2,088 | $2,085 | $2,058 | $2,055 | $2,051 | $2,048 | $2,045 | $2,042 | $24,859 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **36 - Low-Level Radioactive Waste Storage** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $8,861 | $10,182 | $894 | $1,287 | $268 | $3,129 | $77 | $0 | $8,520 | $267 | $0 | $0 | $33,485 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $7,567,919 | $7,576,780 | $7,586,963 | $7,587,857 | $7,589,144 | $7,589,412 | $7,592,541 | $7,592,618 | $7,592,618 | $7,601,138 | $7,601,405 | $7,601,405 | $7,601,405 | N/A |
| 3. Less: Accumulated Depreciation | $307,500 | $318,858 | $330,231 | $341,612 | $352,995 | $364,379 | $375,765 | $387,154 | $398,543 | $409,938 | $421,340 | $432,742 | $444,145 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $7,260,420 | $7,257,922 | $7,256,732 | $7,246,245 | $7,236,149 | $7,225,033 | $7,216,775 | $7,205,464 | $7,194,075 | $7,191,200 | $7,180,064 | $7,168,662 | $7,157,260 | N/A |
| 6. Average Net Investment | | $7,259,171 | $7,257,327 | $7,251,488 | $7,241,197 | $7,230,591 | $7,220,904 | $7,211,120 | $7,199,769 | $7,192,637 | $7,185,632 | $7,174,363 | $7,162,961 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $48,483 | $48,471 | $48,432 | $48,363 | $48,292 | $48,228 | $47,877 | $47,802 | $47,754 | $47,708 | $47,633 | $47,557 | $576,599 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $9,472 | $9,469 | $9,462 | $9,448 | $9,434 | $9,422 | $8,865 | $8,851 | $8,842 | $8,833 | $8,819 | $8,805 | $109,723 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $11,359 | $11,373 | $11,381 | $11,383 | $11,384 | $11,386 | $11,389 | $11,389 | $11,395 | $11,402 | $11,402 | $11,402 | $136,645 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $69,313 | $69,313 | $69,275 | $69,194 | $69,111 | $69,036 | $68,130 | $68,041 | $67,991 | $67,943 | $67,854 | $67,765 | $822,967 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

JANUARY 2014 THROUGH DECEMBER 2014

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **37 - DeSoto Next Generation Solar Energy Center** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($5,992) | $0 | $0 | $3,803 | ($2,189) |
| b. Clearings to Plant | | ($7,391) | $0 | $0 | $0 | ($547) | $24,459 | $0 | $0 | $0 | $57,618 | ($6) | $667 | $74,800 |
| c. Retirements | | ($7,391) | $0 | $0 | $0 | ($547) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($7,937) |
| d. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2. Plant-In-Service/Depreciation Base [a] | $152,920,823 | $152,913,433 | $152,913,433 | $152,913,433 | $152,913,433 | $152,912,886 | $152,937,345 | $152,937,345 | $152,937,345 | $152,937,345 | $152,994,963 | $152,994,957 | $152,995,624 | N/A |
| 3. Less: Accumulated Depreciation | $21,170,748 | $21,588,285 | $22,013,205 | $22,438,124 | $22,863,043 | $23,287,416 | $23,712,363 | $24,137,340 | $24,562,317 | $24,987,295 | $25,412,337 | $25,837,444 | $26,262,552 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($5,992) | $0 | $0 | $3,803 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $131,750,076 | $131,325,147 | $130,900,228 | $130,475,309 | $130,050,389 | $129,625,471 | $129,224,982 | $128,800,005 | $128,375,027 | $127,944,058 | $127,582,626 | $127,157,513 | $126,736,874 | N/A |
| 6. Average Net Investment | | $131,537,612 | $131,112,688 | $130,687,768 | $130,262,849 | $129,837,930 | $129,425,226 | $129,012,493 | $128,587,516 | $128,159,543 | $127,763,342 | $127,370,070 | $126,947,193 | N/A |
| a. Average ITC Balance | | $37,779,537 | $37,657,471 | $37,535,405 | $37,413,339 | $37,291,273 | $37,169,207 | $37,047,141 | $36,925,075 | $36,803,009 | $36,680,943 | $36,558,877 | $36,436,811 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $956,125 | $953,036 | $949,947 | $946,858 | $943,770 | $940,763 | $933,309 | $930,234 | $927,140 | $924,257 | $921,393 | $918,332 | $11,245,163 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $183,002 | $182,411 | $181,820 | $181,228 | $180,637 | $180,062 | $170,291 | $169,730 | $169,165 | $168,640 | $168,118 | $167,559 | $2,102,662 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $418,869 | $418,860 | $418,860 | $418,860 | $418,860 | $418,889 | $418,918 | $418,918 | $418,918 | $418,983 | $419,048 | $419,049 | $5,027,034 |
| b. Amortization [e] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Dismantlement [f] | | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $72,708 |
| 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 Expenses (Lines 7 & 8) | | $1,403,660 | $1,399,971 | $1,396,291 | $1,392,611 | $1,388,931 | $1,385,377 | $1,368,182 | $1,364,546 | $1,360,887 | $1,357,544 | $1,354,223 | $1,350,605 | $16,522,827 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

JANUARY 2014 THROUGH DECEMBER 2014

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **38 - Space Coast Next Generation Solar Energy Center** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | N/A |
| 3. Less: Accumulated Depreciation | $8,798,377 | $8,996,302 | $9,194,227 | $9,392,152 | $9,590,077 | $9,788,001 | $9,985,926 | $10,183,851 | $10,381,776 | $10,579,701 | $10,777,626 | $10,975,551 | $11,173,475 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $61,827,840 | $61,629,915 | $61,431,990 | $61,234,065 | $61,036,140 | $60,838,216 | $60,640,291 | $60,442,366 | $60,244,441 | $60,046,516 | $59,848,591 | $59,650,666 | $59,452,742 | N/A |
| 6. Average Net Investment | | $61,728,877 | $61,530,952 | $61,333,028 | $61,135,103 | $60,937,178 | $60,739,253 | $60,541,328 | $60,343,403 | $60,145,479 | $59,947,554 | $59,749,629 | $59,551,704 | N/A |
| a. Average ITC Balance | | $16,124,403 | $16,073,214 | $16,022,025 | $15,970,836 | $15,919,647 | $15,868,458 | $15,817,269 | $15,766,080 | $15,714,891 | $15,663,702 | $15,612,513 | $15,561,324 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $445,400 | $443,973 | $442,546 | $441,119 | $439,692 | $438,265 | $434,723 | $433,303 | $431,883 | $430,463 | $429,043 | $427,622 | $5,238,030 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $85,397 | $85,124 | $84,850 | $84,576 | $84,303 | $84,029 | $79,417 | $79,157 | $78,898 | $78,639 | $78,379 | $78,120 | $980,889 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $195,013 | $195,013 | $195,013 | $195,013 | $195,013 | $195,013 | $195,013 | $195,013 | $195,013 | $195,013 | $195,013 | $195,013 | $2,340,154 |
| b. Amortization [e] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Dismantlement [f] | | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $34,944 |
| 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 Expenses (Lines 7 & 8) | | $661,459 | $659,758 | $658,058 | $656,357 | $654,656 | $652,955 | $644,802 | $643,122 | $641,443 | $639,763 | $638,084 | $636,404 | $7,786,861 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

JANUARY 2014 THROUGH DECEMBER 2014

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **39 - Martin Next Generation Solar Energy Center** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $1,591,877 | $0 | $13,566 | $10,693 | $75,648 | $21,040 | ($9,375) | $14,900 | ($40,811) | $23,982 | $13,708 | $52,382 | $1,767,610 |
| b. Clearings to Plant | | $3 | $13,020,096 | $51,772 | $147,937 | $174,240 | $86,376 | $1,024 | $15,979 | $353 | $158,272 | $58,760 | $87,096 | $13,801,908 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | ($26,720) | $0 | $21,391 | $0 | $0 | $0 | ($175,608) | ($180,937) |
| d. Other | | $0 | $1,756 | ($66) | $1,638 | ($66) | ($4,001) | ($631) | ($703) | ($998) | ($2,628) | ($3,217) | $15,866 | $6,949 |
| 2. Plant-In-Service/Depreciation Base [a] | $411,841,635 | $411,841,638 | $424,861,734 | $424,913,506 | $425,061,443 | $425,235,684 | $425,322,059 | $425,323,084 | $425,339,062 | $425,339,416 | $425,497,687 | $425,556,447 | $425,643,543 | N/A |
| 3. Less: Accumulated Depreciation | $41,324,983 | $42,489,541 | $43,673,757 | $44,874,125 | $46,076,472 | $47,277,558 | $48,448,347 | $49,649,346 | $50,871,688 | $52,072,366 | $53,271,632 | $54,470,608 | $55,513,258 | N/A |
| 4. CWIP - Non Interest Bearing | $10,858,289 | $12,450,166 | $361,897 | $375,463 | $386,156 | $461,804 | $482,844 | $355,053 | $384,776 | $343,965 | $214,103 | $227,811 | $52,382 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $381,374,941 | $381,802,263 | $381,549,873 | $380,414,843 | $379,371,128 | $378,419,930 | $377,356,557 | $376,028,791 | $374,852,151 | $373,611,015 | $372,440,159 | $371,313,651 | $370,182,667 | N/A |
| 6. Average Net Investment | | $381,588,602 | $381,676,068 | $380,982,358 | $379,892,986 | $378,895,529 | $377,888,243 | $376,692,674 | $375,440,471 | $374,231,583 | $373,025,587 | $371,876,905 | $370,748,159 | N/A |
| a. Average ITC Balance | | $110,974,657 | $110,630,859 | $110,287,061 | $109,943,263 | $109,599,465 | $109,255,667 | $108,911,869 | $108,568,071 | $108,224,273 | $107,880,475 | $107,536,677 | $107,192,879 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $2,776,531 | $2,776,409 | $2,771,069 | $2,763,087 | $2,755,719 | $2,748,286 | $2,726,625 | $2,717,599 | $2,708,860 | $2,700,141 | $2,691,802 | $2,683,596 | $32,819,724 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $531,300 | $531,311 | $530,302 | $528,777 | $527,372 | $525,955 | $497,452 | $495,804 | $494,209 | $492,618 | $491,098 | $489,602 | $6,135,800 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,135,711 | $1,153,613 | $1,171,587 | $1,171,862 | $1,172,305 | $1,172,663 | $1,172,783 | $1,172,807 | $1,172,829 | $1,173,047 | $1,173,346 | $1,173,546 | $14,016,098 |
| b. Amortization [e] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Dismantlement [f] | | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $346,164 |
| 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 Expenses (Lines 7 & 8) | | $4,020,638 | $4,038,429 | $4,050,055 | $4,040,822 | $4,032,492 | $4,023,999 | $3,973,956 | $3,963,305 | $3,952,995 | $3,942,902 | $3,933,342 | $3,923,840 | $47,896,774 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

JANUARY 2014 THROUGH DECEMBER 2014

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **41 - Manatee Temporary Heating System** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | ($2,605,268) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($2,605,268) |
| c. Retirements | | $0 | $0 | $0 | ($2,605,268) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($2,605,268) |
| d. Other | | $0 | $0 | $0 | $0 | $0 | ($0) | $0 | $0 | $0 | $0 | $0 | $0 | ($0) |
| 2. Plant-In-Service/Depreciation Base [a] | $9,889,360 | $9,889,360 | $9,889,360 | $9,889,360 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | N/A |
| 3. Less: Accumulated Depreciation | $8,241,591 | $8,332,660 | $8,423,728 | $8,514,797 | $6,111,982 | $6,147,359 | $6,182,736 | $6,218,113 | $6,253,490 | $6,288,867 | $6,324,244 | $6,359,621 | $6,394,998 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $1,647,770 | $1,556,701 | $1,465,632 | $1,374,563 | $1,172,110 | $1,136,733 | $1,101,356 | $1,065,979 | $1,030,602 | $995,225 | $959,848 | $924,471 | $889,094 | N/A |
| 6. Average Net Investment | | $1,602,235 | $1,511,166 | $1,420,098 | $1,273,337 | $1,154,422 | $1,119,045 | $1,083,668 | $1,048,291 | $1,012,914 | $977,537 | $942,160 | $906,783 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $10,701 | $10,093 | $9,485 | $8,504 | $7,710 | $7,474 | $7,195 | $6,960 | $6,725 | $6,490 | $6,255 | $6,020 | $93,613 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $2,091 | $1,972 | $1,853 | $1,661 | $1,506 | $1,460 | $1,332 | $1,289 | $1,245 | $1,202 | $1,158 | $1,115 | $17,884 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $91,069 | $91,069 | $91,069 | $202,453 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $758,676 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $103,861 | $103,134 | $102,406 | $212,619 | $44,594 | $44,311 | $43,904 | $43,626 | $43,347 | $43,069 | $42,791 | $42,512 | $870,172 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **42 - Turkey Point Cooling Canal Monitoring Plan** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $3,582,753 | $3,582,753 | $3,582,753 | $3,582,753 | $3,582,753 | $3,582,753 | $3,582,753 | $3,582,753 | $3,582,753 | $3,582,753 | $3,582,753 | $3,582,753 | $3,582,753 | N/A |
| 3. Less: Accumulated Depreciation | $196,571 | $201,946 | $207,320 | $212,694 | $218,068 | $223,442 | $228,816 | $234,190 | $239,565 | $244,939 | $250,313 | $255,687 | $261,061 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $3,386,181 | $3,380,807 | $3,375,433 | $3,370,059 | $3,364,685 | $3,359,311 | $3,353,937 | $3,348,563 | $3,343,188 | $3,337,814 | $3,332,440 | $3,327,066 | $3,321,692 | N/A |
| 6. Average Net Investment | | $3,383,494 | $3,378,120 | $3,372,746 | $3,367,372 | $3,361,998 | $3,356,624 | $3,351,250 | $3,345,875 | $3,340,501 | $3,335,127 | $3,329,753 | $3,324,379 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $22,598 | $22,562 | $22,526 | $22,490 | $22,454 | $22,418 | $22,250 | $22,214 | $22,179 | $22,143 | $22,107 | $22,072 | $268,014 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $4,415 | $4,408 | $4,401 | $4,394 | $4,387 | $4,380 | $4,120 | $4,113 | $4,106 | $4,100 | $4,093 | $4,087 | $51,003 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $5,374 | $5,374 | $5,374 | $5,374 | $5,374 | $5,374 | $5,374 | $5,374 | $5,374 | $5,374 | $5,374 | $5,374 | $64,490 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $32,387 | $32,344 | $32,301 | $32,258 | $32,215 | $32,172 | $31,744 | $31,702 | $31,659 | $31,617 | $31,575 | $31,532 | $383,506 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **44 - Martin Plant Barley Barber Swamp Iron Mitigation** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $8,737 | $9,026 | $9,314 | $9,602 | $9,890 | $10,179 | $10,467 | $10,755 | $11,043 | $11,332 | $11,620 | $11,908 | $12,196 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $155,981 | $155,693 | $155,405 | $155,116 | $154,828 | $154,540 | $154,252 | $153,963 | $153,675 | $153,387 | $153,099 | $152,810 | $152,522 | N/A |
| 6. Average Net Investment | | $155,837 | $155,549 | $155,261 | $154,972 | $154,684 | $154,396 | $154,108 | $153,819 | $153,531 | $153,243 | $152,955 | $152,666 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $1,041 | $1,039 | $1,037 | $1,035 | $1,033 | $1,031 | $1,023 | $1,021 | $1,019 | $1,017 | $1,016 | $1,014 | $12,326 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $203 | $203 | $203 | $202 | $202 | $201 | $189 | $189 | $189 | $188 | $188 | $188 | $2,346 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $3,459 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $1,532 | $1,530 | $1,528 | $1,525 | $1,523 | $1,521 | $1,501 | $1,499 | $1,496 | $1,494 | $1,492 | $1,490 | $18,131 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **45 - 800 MW Unit ESP** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $7,354,779 | $8,353,309 | $5,153,553 | $5,218,853 | $2,598,913 | $2,841,570 | $4,553,703 | $2,596,332 | $10,902,373 | $992,425 | $2,553,931 | $0 | $53,119,744 |
| b. Clearings to Plant | | $92,745 | ($74,549) | $1,070,654 | ($216) | $48,187,491 | $254,450 | $37,770 | $18,290 | $32,797 | $147,448 | $7,813 | $52,604,594 | $102,379,286 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| d. Other | | ($84,850) | ($94,182) | $1,721,457 | ($0) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,542,425 |
| 2. Plant-In-Service/Depreciation Base [a] | $106,924,455 | $107,017,200 | $106,942,651 | $108,013,305 | $108,013,089 | $156,200,580 | $156,455,030 | $156,492,799 | $156,511,089 | $156,543,886 | $156,691,334 | $156,699,147 | $209,303,741 | N/A |
| 3. Less: Accumulated Depreciation | $1,090,589 | $1,237,510 | $1,375,118 | $3,329,444 | $3,562,996 | $3,950,879 | $4,286,766 | $4,622,967 | $4,959,227 | $5,295,542 | $5,632,050 | $5,968,725 | $6,362,444 | N/A |
| 4. CWIP - Non Interest Bearing | $45,478,624 | $52,833,403 | $61,186,712 | $66,340,266 | $71,559,119 | $26,077,846 | $28,919,416 | $33,473,120 | $36,069,451 | $46,971,825 | $47,964,250 | $50,518,182 | ($0) | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $151,312,489 | $158,613,093 | $166,754,246 | $171,024,127 | $176,009,212 | $178,327,547 | $181,087,680 | $185,342,952 | $187,621,314 | $198,220,169 | $199,023,534 | $201,248,603 | $202,941,297 | N/A |
| 6. Average Net Investment | | $154,962,791 | $162,683,669 | $168,889,187 | $173,516,670 | $177,168,380 | $179,707,613 | $183,215,316 | $186,482,133 | $192,920,741 | $198,621,851 | $200,136,068 | $202,094,950 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $1,034,977 | $1,086,544 | $1,127,990 | $1,158,896 | $1,183,286 | $1,200,245 | $1,216,424 | $1,238,114 | $1,280,862 | $1,318,713 | $1,328,767 | $1,341,772 | $14,516,591 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $202,195 | $212,270 | $220,367 | $226,405 | $231,169 | $234,482 | $225,227 | $229,242 | $237,157 | $244,166 | $246,027 | $248,435 | $2,757,143 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $231,770 | $231,790 | $232,869 | $233,552 | $387,883 | $335,888 | $336,200 | $336,260 | $336,315 | $336,508 | $336,675 | $393,719 | $3,729,429 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $1,468,943 | $1,530,604 | $1,581,226 | $1,618,853 | $1,802,338 | $1,770,615 | $1,777,851 | $1,803,616 | $1,854,334 | $1,899,388 | $1,911,469 | $1,983,926 | $21,003,163 |

(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 39-42.

[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. 2014 actual period is 4.9230% based on May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2014 actual period is 4.8938% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU. □

[c] The Debt Component for the Jan. – Jun. 2014 actual period is 1.5658% based on May 2013 Surveillance Report and the Debt Component for the Jul. – Dec. 2014 actual period is 1.4751% based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8A, pages 39-42.

(e) Applicable amortization period(s). See Form 42-8A, pages 39-42.

[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. 2014 actual period of 6.437% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2014 actual period of 6.421% reflects a 10.5% return on equity.□

Debt Component: For the Jan. – Jun. 2014 actual period return of 1.927% is based on May 2013 Surveillance Report and for the Jul. – Dec. 2014 actual period return of 1.854% is based on FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8A

JANUARY 2014 THROUGH DECEMBER 2014

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. Working Capital Dr(Cr) | | | | | | | | | | | | | | |
| a. 158.100 Allowance Inventory | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| b. 158.200 Allowances Withheld | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| c. 182.300 Other Regulatory Assets-Losses | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| d. 254.900 Other Regulatory Liabilities-Gains | ($648,005) | ($615,643) | ($583,282) | ($550,921) | ($519,518) | ($487,157) | ($454,741) | ($422,229) | ($389,718) | ($357,206) | ($324,694) | ($292,183) | ($259,671) | |
| 2. Total Working Capital | ($648,005) | ($615,643) | ($583,282) | ($550,921) | ($519,518) | ($487,157) | ($454,741) | ($422,229) | ($389,718) | ($357,206) | ($324,694) | ($292,183) | ($259,671) | |
| 3. Average Net Working Capital Balance | | ($631,824) | ($599,463) | ($567,102) | ($535,220) | ($503,337) | ($470,949) | ($438,485) | ($405,973) | ($373,462) | ($340,950) | ($308,438) | ($275,927) | |
| 4. Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [a] | | ($4,220) | ($4,004) | ($3,788) | ($3,575) | ($3,362) | ($3,145) | ($2,911) | ($2,695) | ($2,480) | ($2,264) | ($2,048) | ($1,832) | |
| b. Debt Component [b] | | ($824) | ($782) | ($740) | ($698) | ($657) | ($614) | ($539) | ($499) | ($459) | ($419) | ($379) | ($339) | |
| 5. Total Return Component [e] | | ($5,044) | ($4,786) | ($4,528) | ($4,273) | ($4,018) | ($3,760) | ($3,450) | ($3,194) | ($2,939) | ($2,683) | ($2,427) | ($2,171) | ($43,273) |
| 6. Expense Dr(Cr) | | | | | | | | | | | | | | |
| a. 411.800 Gains from Dispositions of Allowances | | ($32,361) | ($32,361) | ($32,361) | ($32,361) | ($32,361) | ($32,498) | ($32,512) | ($32,512) | ($32,512) | ($32,512) | ($32,512) | ($32,512) | |
| b. 411.900 Losses from Dispositions of Allowances | | $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 | |
| 7. Net Expense (Lines 6a + 6b + 6c) [f] | | ($32,361) | ($32,361) | ($32,361) | ($32,361) | ($32,361) | ($32,498) | ($32,512) | ($32,512) | ($32,512) | ($32,512) | ($32,512) | ($32,512) | ($389,373) |
| 8. Total System Recoverable Expenses (Lines 5 + 7) | | ($37,405) | ($37,147) | ($36,889) | ($36,634) | ($36,380) | ($36,258) | ($35,962) | ($35,706) | ($35,450) | ($35,194) | ($34,939) | ($34,683) | |
| a. Recoverable Costs Allocated to Energy | | ($37,405) | ($37,147) | ($36,889) | ($36,634) | ($36,380) | ($36,258) | ($35,962) | ($35,706) | ($35,450) | ($35,194) | ($34,939) | ($34,683) | |
| b. Recoverable Costs Allocated to Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 9. Energy Jurisdictional Factor | | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | 95.56846% | |
| 10. Demand Jurisdictional Factor | | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | 95.20688% | |
| 11. Retail Energy-Related Recoverable Costs [c] | | ($35,748) | ($35,501) | ($35,254) | ($35,011) | ($34,767) | ($34,651) | ($34,368) | ($34,124) | ($33,879) | ($33,635) | ($33,390) | ($33,146) | |
| 12. Retail Demand-Related Recoverable Costs [d] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 13. Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | ($35,748) | ($35,501) | ($35,254) | ($35,011) | ($34,767) | ($34,651) | ($34,368) | ($34,124) | ($33,879) | ($33,635) | ($33,390) | ($33,146) | ($413,474) |

[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. 2013 actual period is 4.8339% based on rate case Order No. PSC-13-0023-S-EI and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2013 estimated period is 4.9230% based on the May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[b] The Debt Component for the Jan. – Jun. 2013 actual period is 1.6067% based on rate case Order No. PSC-13-0023-S-EI and the Debt Component for the Jul. – Dec. 2013 estimated period is 1.5658% based on the May 2013 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

[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**
**2014 Annual Capital Depreciation Schedule**

| Project | Function | Unit | Utility | Depreciation Rate / Amortization Period | Plant Balance December 2013 | Plant Balance December 2014 |
|---|---|---|---|---|---|---|
| 002-LOW NOX BURNER TECHNOLOGY | 02 - Steam Generation Plant | Turkey Pt U1 | 31200 | 2.50% | 2,563,376 | 2,563,376 |
| **002-LOW NOX BURNER TECHNOLOGY Total** | | | | | **2,563,376** | **2,563,376** |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Manatee Comm | 31200 | 2.60% | 65,605 | 65,605 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Manatee U1 | 31100 | 2.10% | 56,430 | 56,430 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Manatee U1 | 31200 | 2.60% | 489,772 | 558,926 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Manatee U2 | 31100 | 2.10% | 56,333 | 56,333 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 528,923 | 599,476 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Martin Comm | 31200 | 2.60% | 31,632 | 31,632 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Martin Comm | 31650 | 5-Year | | 123,576 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Martin U1 | 31100 | 2.10% | 36,811 | 36,811 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Martin U1 | 31200 | 2.60% | 533,645 | 533,645 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Martin U2 | 31100 | 2.10% | 36,845 | 36,845 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Martin U2 | 31200 | 2.60% | 529,520 | 529,520 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Scherer U4 | 31200 | 2.60% | 515,653 | 515,653 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | SJRPP - Comm | 31100 | 2.10% | 43,193 | 43,193 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | SJRPP U1 | 31200 | 2.60% | 780 | 780 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | SJRPP U2 | 31200 | 2.60% | 780 | 780 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Turkey Pt Comm | 31100 | 2.10% | 59,056 | 59,056 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Turkey Pt Comm | 31200 | 2.50% | 29,142 | 29,142 |
| 003-CONTINUOUS EMISSION MONITORING | 02 - Steam Generation Plant | Turkey Pt U1 | 31200 | 2.50% | 382,004 | 382,004 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | FtLauderdale Comm | 34100 | 3.50% | 58,860 | 58,860 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | FtLauderdale Comm | 34500 | 3.40% | 34,502 | 34,502 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | FtLauderdale GTs | 34300 | 2.90% | | 10,225 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | FtLauderdale U4 | 34300 | 4.30% | 487,395 | 487,395 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | FtLauderdale U5 | 34300 | 4.20% | 498,340 | 498,340 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | FtMyers U2 | 34300 | 4.20% | 165,032 | 165,032 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | FtMyers U3 | 34300 | 5.20% | 2,283 | 2,283 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | Manatee U3 | 34300 | 4.30% | 87,691 | 87,691 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | Martin U3 | 34300 | 4.20% | 421,385 | 421,385 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | Martin U4 | 34300 | 4.20% | 413,986 | 413,986 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | Martin U8 | 34300 | 4.30% | 13,693 | 13,693 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | Putnam Comm | 34100 | 2.60% | 82,858 | |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | Putnam Comm | 34300 | 4.20% | 3,139 | |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | Putnam U1 | 34300 | 4.00% | 351,988 | |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | Putnam U2 | 34300 | 3.30% | 385,713 | |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | Sanford U4 | 34300 | 4.80% | 171,843 | 171,843 |
| 003-CONTINUOUS EMISSION MONITORING | 05 - Other Generation Plant | Sanford U5 | 34300 | 4.20% | 134,810 | 134,809 |
| **003-CONTINUOUS EMISSION MONITORING Total** | | | | | **6,709,643** | **6,159,452** |
| 004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION | 02 - Steam Generation Plant | Turkey Pt Comm | 31100 | 2.10% | 21,799 | 21,799 |
| **004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION Total** | | | | | **21,799** | **21,799** |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 02 - Steam Generation Plant | Manatee Comm | 31100 | 2.10% | 3,111,263 | 3,111,263 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 02 - Steam Generation Plant | Manatee Comm | 31200 | 2.60% | 174,543 | 174,543 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 02 - Steam Generation Plant | Manatee U1 | 31200 | 2.60% | 104,845 | 104,845 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 127,429 | 127,429 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 02 - Steam Generation Plant | Martin Comm | 31100 | 2.10% | 1,110,450 | 1,110,450 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 02 - Steam Generation Plant | Martin Comm | 31200 | 2.60% | 94,329 | 94,329 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 02 - Steam Generation Plant | Martin U1 | 31100 | 2.10% | 176,339 | 261,417 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 02 - Steam Generation Plant | Martin U2 | 31100 | 2.10% | | 85,078 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 02 - Steam Generation Plant | SJRPP - Comm | 31100 | 2.10% | 42,091 | 42,091 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 02 - Steam Generation Plant | SJRPP - Comm | 31200 | 2.60% | 2,292 | 2,292 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 02 - Steam Generation Plant | Turkey Pt Comm | 31100 | 2.10% | 87,560 | 87,560 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 05 - Other Generation Plant | FtLauderdale Comm | 34200 | 3.80% | 898,111 | 898,111 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 05 - Other Generation Plant | FtLauderdale GTs | 34200 | 2.60% | 584,290 | 584,290 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 05 - Other Generation Plant | FtMyers GTs | 34200 | 2.70% | 133,479 | 133,479 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 05 - Other Generation Plant | FtMyers U3 | 34200 | 3.80% | | 18,616 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 05 - Other Generation Plant | Martin Comm | 34200 | 3.80% | | 450,656 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 05 - Other Generation Plant | PtEverglades GTs | 34200 | 2.60% | 2,768,744 | 2,768,744 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | 05 - Other Generation Plant | Putnam Comm | 34200 | 2.90% | 749,026 | |
| **005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total** | | | | | **10,164,793** | **10,055,195** |
| 007-RELOCATE TURBINE LUBE OIL PIPING | 03 - Nuclear Generation Plant | StLucie U1 | 32300 | 2.40% | 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 | CapeCanaveral Comm | 31650 | 5-Year | 16,332 | |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | CapeCanaveral Comm | 31670 | 7-Year | 24,380 | |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Manatee Comm | 31100 | 2.10% | 46,882 | 46,882 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Manatee Comm | 31650 | 5-Year | 13,508 | |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Manatee Comm | 31670 | 7-Year | 104,179 | 92,617 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Martin Comm | 31600 | 2.40% | 23,107 | 23,107 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Martin Comm | 31650 | 5-Year | 3,883 | 3,883 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Martin Comm | 31670 | 7-Year | 219,776 | 202,707 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Riviera Comm | 31650 | 5-Year | 14,317 | |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Turkey Pt Comm | 31100 | 2.10% | 5,895 | 5,895 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Turkey Pt Comm | 31650 | 5-Year | 14,017 | |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Turkey Pt Comm | 31670 | 7-Year | 2,576 | 2,576 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 05 - Other Generation Plant | FtLauderdale Comm | 34100 | 3.50% | 363,996 | 363,996 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 05 - Other Generation Plant | FtMyers Comm | 34650 | 5-Year | 9,728 | 9,728 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 05 - Other Generation Plant | Putnam Comm | 34650 | 5-Year | 13,184 | |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 05 - Other Generation Plant | Sanford Comm | 34100 | 3.50% | | 16,035 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36670 | 2.00% | | 2,995 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 08 - General Plant | General Plant | 39000 | 2.10% | 4,413 | 4,413 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 08 - General Plant | General Plant | 39190 | 3-Year | | 6,261 |
| **008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total** | | | | | **880,172** | **781,095** |

**Florida Power & Light Company**
**Environmental Cost Recovery Clause**
**2014 Annual Capital Depreciation Schedule**

| Project | Function | Unit | Utility | Depreciation Rate / Amortization Period | Plant Balance December 2013 | Plant Balance December 2014 |
|---|---|---|---|---|---|---|
| 010-REROUTE STORMWATER RUNOFF | 03 - Nuclear Generation Plant | StLucie Comm | 32100 | 1.80% | 117,794 | 117,794 |
| **010-REROUTE STORMWATER RUNOFF Total** | | | | | **117,794** | **117,794** |
| 012-SCHERER DISCHARGE PIPELINE | 02 - Steam Generation Plant | Scherer Comm | 31100 | 2.10% | 524,873 | 524,873 |
| 012-SCHERER DISCHARGE PIPELINE | 02 - Steam Generation Plant | Scherer Comm | 31200 | 2.60% | 328,762 | 328,762 |
| 012-SCHERER DISCHARGE PIPELINE | 02 - Steam Generation Plant | Scherer Comm | 31400 | 2.60% | 689 | 689 |
| **012-SCHERER DISCHARGE PIPELINE Total** | | | | | **854,324** | **854,324** |
| 020-WASTEWATER/STORMWATER DISCH ELIMINATION | 02 - Steam Generation Plant | Martin U1 | 31200 | 2.60% | 367,906 | 367,906 |
| 020-WASTEWATER/STORMWATER DISCH ELIMINATION | 02 - Steam Generation Plant | Martin U2 | 31200 | 2.60% | 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 | 1.80% | 352,942 | 352,942 |
| **021-ST.LUCIE TURTLE NETS Total** | | | | | **352,942** | **352,942** |
| 022-PIPELINE INTEGRITY MANAGEMENT | 02 - Steam Generation Plant | Manatee Comm | 31100 | 2.10% | 620,473 | 620,473 |
| 022-PIPELINE INTEGRITY MANAGEMENT | 02 - Steam Generation Plant | Martin Comm | 31100 | 2.10% | 2,271,574 | 2,271,574 |
| **022-PIPELINE INTEGRITY MANAGEMENT Total** | | | | | **2,892,047** | **2,892,047** |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Manatee Comm | 31100 | 2.10% | 807,621 | 816,259 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Manatee Comm | 31200 | 2.60% | 33,272 | 33,272 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Manatee Comm | 31500 | 2.40% | 26,325 | 26,325 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Manatee U1 | 31200 | 2.60% | 45,750 | 45,750 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 37,431 | 37,431 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Martin Comm | 31100 | 2.10% | 343,785 | 343,785 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Martin Comm | 31500 | 2.40% | 34,755 | 34,755 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Turkey Pt Comm | 31100 | 2.10% | 92,013 | 92,013 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 03 - Nuclear Generation Plant | StLucie U1 | 32300 | 2.40% | 712,225 | 712,225 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 03 - Nuclear Generation Plant | StLucie U1 | 32400 | 1.80% | 745,335 | 745,335 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 03 - Nuclear Generation Plant | StLucie U2 | 32300 | 2.40% | 552,390 | 552,390 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | FtLauderdale Comm | 34100 | 3.50% | 189,219 | 189,219 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | FtLauderdale Comm | 34200 | 3.80% | 1,480,169 | 1,480,169 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | FtLauderdale Comm | 34300 | 6.00% | 28,250 | 28,250 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | FtLauderdale GTs | 34100 | 2.20% | 92,727 | 92,727 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | FtLauderdale GTs | 34200 | 2.60% | 513,250 | 513,250 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | FtMyers GTs | 34100 | 2.30% | 98,715 | 98,715 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | FtMyers GTs | 34200 | 2.70% | 629,983 | 629,983 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | FtMyers GTs | 34500 | 2.20% | 12,430 | 12,430 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | FtMyers U2 | 34300 | 4.20% | 49,727 | 49,727 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | FtMyers U3 | 34500 | 3.40% | 12,430 | 12,430 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Martin Comm | 34100 | 3.50% | 507,673 | 523,498 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Martin U8 | 34200 | 3.80% | 84,868 | 84,868 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | PtEverglades GTs | 34100 | 2.20% | 454,081 | 454,081 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | PtEverglades GTs | 34200 | 2.60% | 1,835,190 | 1,835,190 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | PtEverglades GTs | 34500 | 2.10% | 7,783 | 7,783 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Putnam Comm | 34100 | 2.60% | 148,511 | |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Putnam Comm | 34200 | 2.90% | 1,730,935 | |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Putnam Comm | 34500 | 2.50% | 60,747 | |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Sanford Comm | 34100 | 3.50% | 288,383 | 288,383 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35200 | 1.90% | 1,069,992 | 1,099,331 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35300 | 2.60% | 177,982 | 177,982 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35800 | 1.80% | 65,655 | 65,655 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36100 | 1.90% | 3,021,242 | 3,117,540 |
| 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 | 2.10% | 146,691 | 146,691 |
| **023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES Total** | | | | | **16,208,033** | **14,417,942** |
| 024-GAS REBURN | 02 - Steam Generation Plant | Manatee U1 | 31200 | 2.60% | 16,687,067 | 16,687,067 |
| 024-GAS REBURN | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 14,483,504 | 15,277,112 |
| **024-GAS REBURN Total** | | | | | **31,170,571** | **31,964,179** |
| 026-UST REPLACEMENT/REMOVAL | 08 - General Plant | General Plant | 39000 | 2.10% | 115,447 | 115,447 |
| **026-UST REPLACEMENT/REMOVAL Total** | | | | | **115,447** | **115,447** |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Manatee Comm | 31100 | 2.10% | 102,052 | 102,052 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Manatee U1 | 31200 | 2.60% | 20,059,060 | 20,059,060 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Manatee U1 | 31400 | 2.60% | 7,240,711 | 7,240,711 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 20,568,600 | 20,461,529 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Manatee U2 | 31400 | 2.60% | 7,905,907 | 7,905,907 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin Comm | 31200 | 2.60% | 518,275 | 518,275 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin Comm | 31400 | 2.60% | 287,258 | 287,258 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin U1 | 31200 | 2.60% | 19,504,077 | 19,504,077 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin U1 | 31400 | 2.60% | 7,794,707 | 7,499,710 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin U2 | 31200 | 2.60% | 20,248,975 | 20,248,975 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin U2 | 31400 | 2.60% | 7,477,120 | 7,477,120 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer U4 | 31100 | 2.10% | | 83,049,769 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer U4 | 31200 | 2.60% | 347,320,881 | 252,034,914 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer U4 | 31400 | 2.60% | | 507,244 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer U4 | 31500 | 2.40% | | 19,237,659 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer U4 | 31600 | 2.40% | | 2,206,227 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer U4 | 31670 | 7-Year | | 12,507 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | SJRPP U1 | 31200 | 2.60% | 27,706,752 | 27,740,234 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | SJRPP U1 | 31500 | 2.40% | 451,890 | 451,890 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | SJRPP U1 | 31600 | 2.40% | 9,138 | 9,138 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | SJRPP U2 | 31200 | 2.60% | 26,532,287 | 26,534,954 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | SJRPP U2 | 31500 | 2.40% | 426,220 | 426,220 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | SJRPP U2 | 31600 | 2.40% | 9,591 | 9,591 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | FtLauderdale GTs | 34300 | 2.90% | 110,242 | 110,242 |

**Florida Power & Light Company**
**Environmental Cost Recovery Clause**
**2014 Annual Capital Depreciation Schedule**

| Project | Function | Unit | Utility | Depreciation Rate / Amortization Period | Plant Balance December 2013 | Plant Balance December 2014 |
|---|---|---|---|---|---|---|
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | FtMyers GTs | 34300 | 3.10% | 57,855 | 57,855 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | Martin Comm | 34100 | 3.50% | 763,350 | 763,350 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | Martin Comm | 34300 | 4.30% | 244,343 | 244,343 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | Martin Comm | 34500 | 3.40% | 292,499 | 292,499 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | PtEverglades GTs | 34300 | 3.40% | 107,874 | 107,874 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36500 | 3.90% | 411,775 | 411,775 |
| **031-CLEAN AIR INTERSTATE RULE-CAIR Total** | | | | | **516,151,440** | **525,512,958** |
| 033-CLEAN AIR MERCURY RULE-CAMR - | 02 - Steam Generation Plant | Scherer U4 | 31100 | 2.10% | 225,600 | 225,600 |
| 033-CLEAN AIR MERCURY RULE-CAMR - | 02 - Steam Generation Plant | Scherer U4 | 31200 | 2.60% | 106,958,839 | 106,958,839 |
| **033-CLEAN AIR MERCURY RULE-CAMR - Total** | | | | | **107,184,439** | **107,184,439** |
| 035-MARTIN PLANT DRINKING WATER COMP | 02 - Steam Generation Plant | Martin Comm | 31100 | 2.10% | 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 | 1.80% | 7,567,919 | 7,601,405 |
| **036-LOW LEV RADI WSTE-LLW Total** | | | | | **7,567,919** | **7,601,405** |
| 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 | 3.30% | 4,502,770 | 4,502,770 |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto Solar | 34300 | 3.30% | 115,303,900 | 115,297,908 |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto Solar | 34500 | 3.30% | 26,746,266 | 26,746,266 |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto Solar | 34630 | 3-Year | 20,537 | 20,537 |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto Solar | 34650 | 5-Year | 21,935 | 21,935 |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto Solar | 34670 | 7-Year | 97,753 | 97,753 |
| 037-DE SOTO SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35200 | 1.90% | 7,427 | 7,427 |
| 037-DE SOTO SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35300 | 2.60% | 1,203,890 | 1,232,527 |
| 037-DE SOTO SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35310 | 2.90% | 1,646,481 | 1,698,382 |
| 037-DE SOTO SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35500 | 3.40% | 394,418 | 394,418 |
| 037-DE SOTO SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35600 | 3.20% | 191,358 | 191,358 |
| 037-DE SOTO SOLAR PROJECT | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36100 | 1.90% | 540,994 | 540,994 |
| 037-DE SOTO SOLAR PROJECT | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36200 | 2.60% | 1,937,924 | 1,938,179 |
| 037-DE SOTO SOLAR PROJECT | 08 - General Plant | General Plant | 39220 | 9.40% | 28,426 | 28,426 |
| 037-DE SOTO SOLAR PROJECT | 08 - General Plant | General Plant | 39720 | 7-Year | 21,238 | 21,238 |
| **037-DE SOTO SOLAR PROJECT Total** | | | | | **152,920,823** | **152,995,624** |
| 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 | 3.30% | 3,838,726 | 3,838,726 |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast Solar | 34300 | 3.30% | 51,606,083 | 51,606,083 |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast Solar | 34500 | 3.30% | 6,126,699 | 6,126,699 |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast Solar | 34630 | 3-Year | 1,310 | 1,310 |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast Solar | 34650 | 5-Year | 9,438 | 9,438 |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast Solar | 34670 | 7-Year | 51,560 | 51,560 |
| 038-SPACE COAST SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35300 | 2.60% | 928,529 | 928,529 |
| 038-SPACE COAST SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35310 | 2.90% | 1,328,699 | 1,328,699 |
| 038-SPACE COAST SOLAR PROJECT | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36100 | 1.90% | 274,858 | 274,858 |
| 038-SPACE COAST SOLAR PROJECT | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36200 | 2.60% | 62,689 | 62,689 |
| 038-SPACE COAST SOLAR PROJECT | 08 - General Plant | General Plant | 39220 | 9.40% | 31,858 | 31,858 |
| 038-SPACE COAST SOLAR PROJECT | 08 - General Plant | General Plant | 39720 | 7-Year | 6,741 | 6,741 |
| **038-SPACE COAST SOLAR PROJECT Total** | | | | | **70,626,217** | **70,626,217** |
| 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 | 3.30% | 20,741,640 | 20,746,646 |
| 039-MARTIN SOLAR PROJECT | 05 - Other Generation Plant | Martin Solar | 34300 | 3.30% | 384,652,880 | 398,450,800 |
| 039-MARTIN SOLAR PROJECT | 05 - Other Generation Plant | Martin Solar | 34500 | 3.30% | 4,126,222 | 4,125,204 |
| 039-MARTIN SOLAR PROJECT | 05 - Other Generation Plant | Martin Solar | 34600 | 3.30% | 1,299 | 1,299 |
| 039-MARTIN SOLAR PROJECT | 05 - Other Generation Plant | Martin Solar | 34650 | 5-Year | 32,562 | 32,562 |
| 039-MARTIN SOLAR PROJECT | 05 - Other Generation Plant | Martin Solar | 34670 | 7-Year | 11,896 | 11,896 |
| 039-MARTIN SOLAR PROJECT | 05 - Other Generation Plant | Martin U8 | 34300 | 4.30% | 423,126 | 423,126 |
| 039-MARTIN SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35500 | 3.40% | 603,692 | 603,692 |
| 039-MARTIN SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35600 | 3.20% | 364,159 | 364,159 |
| 039-MARTIN SOLAR PROJECT | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36400 | 4.10% | 9,282 | 9,282 |
| 039-MARTIN SOLAR PROJECT | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36660 | 1.50% | 94,476 | 94,476 |
| 039-MARTIN SOLAR PROJECT | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36760 | 2.60% | 2,728 | 2,728 |
| 039-MARTIN SOLAR PROJECT | 08 - General Plant | General Plant | 39220 | 9.40% | 25,193 | 25,193 |
| 039-MARTIN SOLAR PROJECT | 08 - General Plant | General Plant | 39240 | 11.10% | 399,176 | 399,176 |
| 039-MARTIN SOLAR PROJECT | 08 - General Plant | General Plant | 39290 | 3.50% | 114,262 | 114,262 |
| 039-MARTIN SOLAR PROJECT | 08 - General Plant | General Plant | 39420 | 7-Year | 18,993 | 18,993 |
| 039-MARTIN SOLAR PROJECT | 08 - General Plant | General Plant | 39720 | 7-Year | 3,204 | 3,204 |
| **039-MARTIN SOLAR PROJECT Total** | | | | | **411,841,635** | **425,643,543** |
| 041-PRV MANATEE HEATING SYSTEM | 02 - Steam Generation Plant | CapeCanaveral Comm | 31400 | 39 mos. | 4,042,459 | |
| 041-PRV MANATEE HEATING SYSTEM | 02 - Steam Generation Plant | PtEverglades Comm | 31400 | 42 mos. | 1,478,577 | 1,478,577 |
| 041-PRV MANATEE HEATING SYSTEM | 02 - Steam Generation Plant | Riviera Comm | 31400 | 56 mos. | 2,605,268 | |
| 041-PRV MANATEE HEATING SYSTEM | 05 - Other Generation Plant | CapeCanaveral Comm | 34300 | 39 mos. | | 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 | 472,661 |
| 041-PRV MANATEE HEATING SYSTEM | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36400 | various | 225,952 | 225,952 |
| 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 | 16,244 |
| **041-PRV MANATEE HEATING SYSTEM Total** | | | | | **9,889,360** | **7,284,092** |

**Florida Power & Light Company**
**Environmental Cost Recovery Clause**
**2014 Annual Capital Depreciation Schedule**

| Project | Function | Unit | Utility | Depreciation Rate / Amortization Period | Plant Balance December 2013 | Plant Balance December 2014 |
|---|---|---|---|---|---|---|
| 042-PTN COOLING CANAL MONITORING SYS | 03 - Nuclear Generation Plant | Turkey Pt Comm | 32100 | 1.80% | 3,582,753 | 3,582,753 |
| **042-PTN COOLING CANAL MONITORING SYS Total** | | | | | **3,582,753** | **3,582,753** |
| 044-Barley Barber Swamp Iron Mitiga | 02 - Steam Generation Plant | Martin Comm | 31100 | 2.10% | 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 U1 | 31200 | 2.60% | 49,762,056 | 44,965,950 |
| 045-800 MW UNIT ESP PROJECT | 02 - Steam Generation Plant | Manatee U1 | 31500 | 2.40% | | 4,409,109 |
| 045-800 MW UNIT ESP PROJECT | 02 - Steam Generation Plant | Manatee U1 | 31600 | 2.40% | | 1,021,783 |
| 045-800 MW UNIT ESP PROJECT | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 57,158,247 | 51,910,750 |
| 045-800 MW UNIT ESP PROJECT | 02 - Steam Generation Plant | Manatee U2 | 31500 | 2.40% | | 4,661,952 |
| 045-800 MW UNIT ESP PROJECT | 02 - Steam Generation Plant | Manatee U2 | 31600 | 2.40% | | 1,051,553 |
| 045-800 MW UNIT ESP PROJECT | 02 - Steam Generation Plant | Martin U1 | 31200 | 2.60% | 4,152 | 46,720,527 |
| 045-800 MW UNIT ESP PROJECT | 02 - Steam Generation Plant | Martin U1 | 31500 | 2.40% | | 4,288,249 |
| 045-800 MW UNIT ESP PROJECT | 02 - Steam Generation Plant | Martin U1 | 31600 | 2.40% | | 993,796 |
| 045-800 MW UNIT ESP PROJECT | 02 - Steam Generation Plant | Martin U2 | 31200 | 2.60% | | 49,280,072 |
| **045-800 MW UNIT ESP PROJECT Total** | | | | | **106,924,455** | **209,303,741** |
| **Grand Total** | | | | | 1,459,942,701 | 1,581,233,081 |

**FLORIDA POWER & LIGHT COMPANY**
**COST RECOVERY CLAUSES**

**Equity @ 10.50%**

**CAPITAL STRUCTURE AND COST RATES PER MAY 2013 EARNINGS SURVEILLANCE REPORT**

| | ADJUSTED RETAIL | RATIO | MIDPOINT COST RATES | WEIGHTED COST | PRE-TAX WEIGHTED COST |
|---|---|---|---|---|---|
| LONG_TERM_DEBT | 6,416,467,850 | 29.591% | 4.981% | 1.474% | 1.474% |
| SHORT_TERM_DEBT | 431,179,727 | 1.989% | 1.833% | 0.036% | 0.036% |
| PREFERRED_STOCK | 0 | 0.000% | 0.000% | 0.000% | 0.000% |
| CUSTOMER_DEPOSITS | 428,779,347 | 1.977% | 2.796% | 0.055% | 0.055% |
| COMMON_EQUITY | 10,165,729,253 | 46.882% | 10.500% | 4.923% | 8.014% |
| DEFERRED_INCOME_TAX | 4,240,131,465 | 19.555% | 0.000% | 0.000% | 0.000% |
| INVESTMENT_TAX_CREDITS | | | | | |
| ZERO COST | 0 | 0.000% | 0.000% | 0.000% | 0.000% |
| WEIGHTED COST | 1,324,684 | 0.006% | 8.364% | 0.001% | 0.001% |
| TOTAL | $21,683,612,327 | 100.00% | | 6.489% | 9.580% |

**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 | $6,416,467,850 | 38.69% | 4.981% | 1.927% | 1.927% |
| PREFERRED STOCK | 0 | 0.00% | 0.000% | 0.000% | 0.000% |
| COMMON EQUITY | 10,165,729,253 | 61.31% | 10.500% | 6.437% | 10.480% |
| TOTAL | $16,582,197,103 | 100.00% | | 8.364% | 12.407% |
| RATIO | | | | | |
| DEBT COMPONENTS: | | | | | |
| LONG TERM DEBT | 1.4740% | | | | |
| SHORT TERM DEBT | 0.0364% | | | | |
| CUSTOMER DEPOSITS | 0.0553% | | | | |
| TAX CREDITS -WEIGHTED | 0.0001% | | | | |
| TOTAL DEBT | **1.5658%** | | | | |
| EQUITY COMPONENTS: | | | | | |
| PREFERRED STOCK | 0.0000% | | | | |
| COMMON EQUITY | 4.9226% | | | | |
| TAX CREDITS -WEIGHTED | 0.0004% | | | | |
| TOTAL EQUITY | **4.9230%** | | | | |
| TOTAL | 6.4889% | | | | |
| PRE-TAX EQUITY | 8.0147% | | | | |
| PRE-TAX TOTAL | 9.5805% | | | | |

**Note:**

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

**FLORIDA POWER & LIGHT COMPANY**
**COST RECOVERY CLAUSES**

**CAPITAL STRUCTURE AND COST RATES PER**
**MAY 2014 EARNINGS SURVEILLANCE REPORT**

**Equity @ 10.50%**

| | ADJUSTED RETAIL | RATIO | MIDPOINT COST RATES | WEIGHTED COST | PRE-TAX WEIGHTED COST |
|---|---|---|---|---|---|
| LONG_TERM_DEBT | 7,260,190,891 | 29.609% | 4.77% | 1.41% | 1.41% |
| SHORT_TERM_DEBT | 303,811,216 | 1.239% | 2.18% | 0.03% | 0.03% |
| PREFERRED_STOCK | 0 | 0.000% | 0.00% | 0.00% | 0.00% |
| CUSTOMER_DEPOSITS | 422,415,505 | 1.723% | 2.04% | 0.04% | 0.04% |
| COMMON_EQUITY | 11,427,411,916 | 46.604% | 10.50% | 4.89% | 7.97% |
| DEFERRED_INCOME_TAX | 5,104,824,995 | 20.819% | 0.00% | 0.00% | 0.00% |
| INVESTMENT_TAX_CREDITS | | | | | |
| ZERO COST | 0 | 0.000% | 0.00% | 0.00% | 0.00% |
| WEIGHTED COST | 1,326,963 | 0.005% | 8.27% | 0.00% | 0.00% |
| TOTAL | $24,519,981,486 | 100.00% | | 6.37% | 9.44% |

**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 | $7,260,190,891 | 38.85% | 4.772% | 1.854% | 1.854% |
| PREFERRED STOCK | 0 | 0.00% | 0.000% | 0.000% | 0.000% |
| COMMON EQUITY | 11,427,411,916 | 61.15% | 10.500% | 6.421% | 10.453% |
| TOTAL | $18,687,602,807 | 100.00% | | 8.275% | 12.307% |
| RATIO | | | | | |

DEBT COMPONENTS:

| | |
|---|---|
| LONG TERM DEBT | 1.4129% |
| SHORT TERM DEBT | 0.0270% |
| CUSTOMER DEPOSITS | 0.0352% |
| TAX CREDITS -WEIGHTED | 0.0001% |
| TOTAL DEBT | **1.4751%** |

EQUITY COMPONENTS:

| | |
|---|---|
| PREFERRED STOCK | 0.0000% |
| COMMON EQUITY | 4.8935% |
| TAX CREDITS -WEIGHTED | 0.0003% |
| TOTAL EQUITY | **4.8938%** |
| TOTAL | 6.3690% |
| PRE-TAX EQUITY | 7.9671% |
| PRE-TAX TOTAL | 9.4423% |

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

# APPENDIX I

## ENVIRONMENTAL COST RECOVERY
## COMMISSION FORMS 42-1E THROUGH 42-9E

## JANUARY 2015 - DECEMBER 2015
## ACTUAL/ESTIMATED TRUE-UP

TJK-2
DOCKET NO. 150007-EI
EXHIBIT_____
PAGES 1-43
JULY 31, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 7
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Terry J. Keith TJK-2

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

FORM: 42-1E

JANUARY 2015 THROUGH DECEMBER 2015

| | |
|---|---|
| 1. Over/(Under) Recovery for the Current Period (Form 42-2E Page 2, Line 5) | ($37,603,104) |
| 2. Interest Provision (Form 42-2E Page 2, Line 6) | ($16,608) |
| 3. Sum of Current Period Adjustments (Form 42-2E, Page 2, Line 10) | $0 |
| 4. Actual/Estimated True-up to be refunded/(recovered) | ($37,619,712) |

Note: Totals may not add due to rounding.

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

FORM: 42-2E

JANUARY 2015 THROUGH DECEMBER 2015

| | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. ECRC Revenues (net of Revenue Taxes) | $14,994,434 | $13,390,342 | $14,631,270 | $16,320,501 | $17,778,642 | $19,021,688 | $19,377,295 | $20,761,040 | $19,876,968 | $17,880,070 | $15,824,203 | $15,330,226 | $205,186,680 |
| 2. True-up Provision [1] | $320,540 | $320,540 | $320,540 | $320,540 | $320,540 | $320,540 | $320,540 | $320,540 | $320,540 | $320,540 | $320,540 | $320,540 | $3,846,483 |
| 3. ECRC Revenues Applicable to Period (Lines 1 + 2) | $15,314,974 | $13,710,882 | $14,951,811 | $16,641,041 | $18,099,183 | $19,342,229 | $19,697,836 | $21,081,580 | $20,197,509 | $18,200,611 | $16,144,743 | $15,650,766 | $209,033,163 |
| 4. Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| a. O&M Activities (Form 42-5E, Line 9) | $2,825,504 | $4,430,805 | $3,948,350 | $3,299,451 | $4,640,375 | $5,699,397 | $5,356,926 | $6,414,191 | $11,175,607 | $9,926,707 | $3,705,546 | $2,546,079 | $63,968,938 |
| b. Capital Investment Projects (Form 42-7E, Line 9) | $15,330,212 | $15,360,844 | $15,347,710 | $15,359,439 | $15,348,523 | $15,319,298 | $15,179,709 | $15,145,994 | $15,114,352 | $15,082,280 | $15,050,185 | $15,028,783 | $182,667,329 |
| c. Total Jurisdictional ECRC Costs | $18,155,716 | $19,791,649 | $19,296,060 | $18,658,889 | $19,988,897 | $21,018,694 | $20,536,634 | $21,560,186 | $26,289,959 | $25,008,987 | $18,755,732 | $17,574,862 | $246,636,267 |
| 5. Over/(Under) Recovery (Line 3 - Line 4c) | ($2,840,742) | ($6,080,767) | ($4,344,250) | ($2,017,848) | ($1,889,715) | ($1,676,466) | ($838,799) | ($478,605) | ($6,092,451) | ($6,808,377) | ($2,610,989) | ($1,924,096) | ($37,603,104) |
| 6. Interest Provision (Form 42-3E, Line 10) | ($75) | ($450) | ($841) | ($920) | ($1,133) | ($1,432) | ($1,378) | ($1,444) | ($1,684) | ($2,136) | ($2,471) | ($2,644) | ($16,608) |
| 7. Prior Periods True-Up to be (Collected)/Refunded | $3,846,483 | $685,125 | ($5,716,631) | ($10,382,262) | ($12,721,570) | ($14,932,958) | ($16,931,396) | ($18,092,114) | ($18,892,703) | ($25,307,378) | ($32,438,431) | ($35,372,431) | $3,846,483 |
| a. Deferred True-Up (Form 42-1A, Line 7) [2] | ($3,164,408) | ($3,164,408) | ($3,164,408) | ($3,164,408) | ($3,164,408) | ($3,164,408) | ($3,164,408) | ($3,164,408) | ($3,164,408) | ($3,164,408) | ($3,164,408) | ($3,164,408) | $0 |
| 8. True-Up Collected /(Refunded) (See Line 2) | ($320,540) | ($320,540) | ($320,540) | ($320,540) | ($320,540) | ($320,540) | ($320,540) | ($320,540) | ($320,540) | ($320,540) | ($320,540) | ($320,540) | ($3,846,483) |
| 9. End of Period True-Up (Lines 5+6+7+7a+8) | ($2,479,283) | ($8,881,039) | ($13,546,670) | ($15,885,978) | ($18,097,366) | ($20,095,804) | ($21,256,522) | ($22,057,111) | ($28,471,786) | ($35,602,839) | ($38,536,839) | ($40,784,120) | ($37,619,712) |
| 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) | ($2,479,283) | ($8,881,039) | ($13,546,670) | ($15,885,978) | ($18,097,366) | ($20,095,804) | ($21,256,522) | ($22,057,111) | ($28,471,786) | ($35,602,839) | ($38,536,839) | ($40,784,120) | ($37,619,712) |

[1] As approved in Order No. PSC-14-0643-FOF-EI issued November 4, 2014 and Order No. PSC-14-0714-FOF-EI issued December 31, 2014.

[2] From FPL's 2014 Final True-up filed on April 1, 2015.

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

FORM: 42-3E

JANUARY 2015 THROUGH DECEMBER 2015

| | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | 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) | $682,075 | ($2,479,283) | ($8,881,039) | ($13,546,670) | ($15,885,978) | ($18,097,366) | ($20,095,804) | ($21,256,522) | ($22,057,111) | ($28,471,786) | ($35,602,839) | ($38,536,839) | N/A |
| 2. Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8) | ($2,479,208) | ($8,880,589) | ($13,545,829) | ($15,885,059) | ($18,096,233) | ($20,094,372) | ($21,255,143) | ($22,055,667) | ($28,470,102) | ($35,600,703) | ($38,534,368) | ($40,781,476) | N/A |
| 3. Total of Beginning & Ending True-Up (Lines 1 + 2) | ($1,797,133) | ($11,359,872) | ($22,426,868) | ($29,431,729) | ($33,982,212) | ($38,191,738) | ($41,350,948) | ($43,312,189) | ($50,527,213) | ($64,072,490) | ($74,137,207) | ($79,318,315) | N/A |
| 4. Average True-Up Amount (Line 3 x 1/2) | ($898,566) | ($5,679,936) | ($11,213,434) | ($14,715,864) | ($16,991,106) | ($19,095,869) | ($20,675,474) | ($21,656,094) | ($25,263,607) | ($32,036,245) | ($37,068,604) | ($39,659,157) | N/A |
| 5. Interest Rate (First Day of Reporting Month) | 0.10000% | 0.10000% | 0.09000% | 0.09000% | 0.06000% | 0.10000% | 0.08000% | 0.08000% | 0.08000% | 0.08000% | 0.08000% | 0.08000% | N/A |
| 6. Interest Rate (First Day of Subsequent Month) | 0.10000% | 0.09000% | 0.09000% | 0.06000% | 0.10000% | 0.08000% | 0.08000% | 0.08000% | 0.08000% | 0.08000% | 0.08000% | 0.08000% | N/A |
| 7. Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 0.20000% | 0.19000% | 0.18000% | 0.15000% | 0.16000% | 0.18000% | 0.16000% | 0.16000% | 0.16000% | 0.16000% | 0.16000% | 0.16000% | N/A |
| 8. Average Interest Rate (Line 7 x 1/2) | 0.10000% | 0.09500% | 0.09000% | 0.07500% | 0.08000% | 0.09000% | 0.08000% | 0.08000% | 0.08000% | 0.08000% | 0.08000% | 0.08000% | N/A |
| 9. Monthly Average Interest Rate (Line 8 x 1/12) | 0.00833% | 0.00792% | 0.00750% | 0.00625% | 0.00667% | 0.00750% | 0.00667% | 0.00667% | 0.00667% | 0.00667% | 0.00667% | 0.00667% | N/A |
| 10. Interest Provision for the Month (Line 4 x Line 9) | ($75) | ($450) | ($841) | ($920) | ($1,133) | ($1,432) | ($1,378) | ($1,444) | ($1,684) | ($2,136) | ($2,471) | ($2,644) | ($16,608) |

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

FORM: 42-4E-1

JANUARY 2015 THROUGH DECEMBER 2015

VARIANCE REPORT OF O&M ACTIVITIES

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| PROJECT # | ECRC - 2015 Actual/Estimated [a] | ECRC - 2015 Original Projection [b] | Dif. ECRC - 2015 Original Projection [c] | % Dif. ECRC - 2015 Original Projection [d] |
| 1. Description of O&M Activities | | | | |
| 1 - Air Operating Permit Fees | $565,078 | $280,666 | $284,412 | 101.3% |
| 3a - Continuous Emission Monitoring Systems | $735,641 | $698,100 | $37,541 | 5.4% |
| 5a - Maintenance of Stationary Above Ground Fuel Storage Tanks | $2,261,068 | $2,190,044 | $71,024 | 3.2% |
| 8a - Oil Spill Clean-up/Response Equipment | $204,509 | $204,585 | ($75) | (0.0%) |
| 14 - NPDES Permit Fees | $80,700 | $80,700 | $0 | 0.0% |
| 17a - Disposal of Non-Containerized Liquid Waste | $2,631 | $65,000 | ($62,369) | (96.0%) |
| 19a - Substation Pollutant Discharge Prevention & Removal - Distribution | $2,520,847 | $1,815,000 | $705,847 | 38.9% |
| 19b - Substation Pollutant Discharge Prevention & Removal - Transmission | $1,300,684 | $1,855,000 | ($554,316) | (29.9%) |
| NA - Amortization of Gains on Sales of Emissions Allowances | ($241,529) | ($241,452) | ($77) | 0.0% |
| 21 - St. Lucie Turtle Nets | $110,000 | $0 | $110,000 | N/A |
| 22 - Pipeline Integrity Management | $854,770 | $388,500 | $466,270 | 120.0% |
| 23 - SPCC - Spill Prevention, Control & Countermeasures | $928,054 | $1,209,250 | ($281,195) | (23.3%) |
| 24 - Manatee Reburn | $333,459 | $350,236 | ($16,777) | (4.8%) |
| 27 - Lowest Quality Water Source | $135,557 | $162,000 | ($26,443) | (16.3%) |
| 28 - CWA 316(b) Phase II Rule | $671,754 | $1,125,309 | ($453,555) | (40.3%) |
| 29 - SCR Consumables | $586,552 | $575,580 | $10,972 | 1.9% |
| 30 - HBMP | $27,500 | $22,500 | $5,000 | 22.2% |
| 31 - Clean Air Interstate Rule (CAIR) Compliance | $4,685,283 | $4,895,147 | ($209,864) | (4.3%) |
| 33 - MATS Project | $2,647,668 | $2,371,759 | $275,909 | 11.6% |
| 35 - Martin Plant Drinking Water System Compliance | $65,009 | $26,400 | $38,609 | 146.2% |
| 37 - DeSoto Next Generation Solar Energy Center | $1,067,268 | $1,094,514 | ($27,246) | (2.5%) |
| 38 - Space Coast Next Generation Solar Energy Center | $269,081 | $286,217 | ($17,136) | (6.0%) |
| 39 - Martin Next Generation Solar Energy Center | $3,674,111 | $3,530,899 | $143,212 | 4.1% |
| 40 - Greenhouse Gas Reduction Program | $78,852 | $70,000 | $8,852 | 12.6% |
| 41 - Manatee Temporary Heating System | $295,687 | $331,589 | ($35,902) | (10.8%) |
| 42 - Turkey Point Cooling Canal Monitoring Plan | $41,408,582 | $1,501,800 | $39,906,782 | 2,657.3% |
| 45 - 800 MW Unit ESP | $1,080,389 | $1,393,782 | ($313,393) | (22.5%) |
| 46 - St. Lucie Cooling Water Discharge Monitoring | $112,928 | $271,751 | ($158,823) | (58.4%) |
| 47 - NPDES Permit Renewal Requirements | $69,110 | $70,430 | ($1,320) | (1.9%) |
| 48 - Industrial Boiler MACT | $10,496 | $6,000 | $4,496 | 74.9% |
| 49 - Thermal Discharge Standards | $69,931 | $40,574 | $29,357 | 72.4% |
| 50 - Steam Electric Effluent Guidelines Revised Rules | $395,234 | $0 | $395,234 | N/A |
| 51 - Gopher Tortoise Relocations | $59,000 | $24,000 | $35,000 | 145.8% |
| 52 - Numeric Nutrient Criteria Water Quality Standards in Florida | $38,000 | $0 | $38,000 | N/A |
| 2. Total O&M Activities | $67,103,906 | $26,695,879 | $40,408,027 | 151.4% |

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

[b] As approved in Order No. PSC-14-0643-FOF-EI issued November 4, 2014 and Order No. PSC 14-0714-FOF-EI issued December 31, 2014

[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 2015 THROUGH DECEMBER 2015

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| | ECRC - 2015 Actual/Estimated [(a)] | ECRC - 2015 Original Projection [(b)] | Dif. ECRC - 2015 Original Projection [(c)] | % Dif. ECRC - 2015 Original Projection [(d)] |
| 2. Total of O&M Activities | $67,103,906 | $26,695,879 | $40,408,027 | 151.4% |
| 3. Recoverable Costs Allocated to Energy | $52,482,856 | $12,639,484 | $39,843,371 | 315.2% |
| 4a. Recoverable Costs Allocated to CP Demand | $12,100,203 | $12,241,395 | ($141,192) | (1.2%) |
| 4b. Recoverable Costs Allocated to GCP Demand | $2,520,847 | $1,815,000 | $705,847 | 38.9% |
| 7. Jurisdictional Energy Recoverable Costs | $49,995,735 | $12,040,509 | $37,955,226 | 315.2% |
| 8a. Jurisdictional CP Demand Recoverable Costs | $11,452,356 | $11,585,988 | ($133,632) | (1.2%) |
| 8b. Jurisdictional GCP Demand Recoverable Costs | $2,520,847 | $1,815,000 | $705,847 | 38.9% |
| 9. Total Jurisdictional Recoverable Costs for O&M Activities | $63,968,938 | $25,441,497 | $38,527,440 | 151.4% |

[(a)] The 12-Month Totals on Form 42-5E

[(b)] As approved in Order No. PSC-14-0643-FOF-EI issued November 4, 2014 and Order No. PSC-14-0714-FOF-EI issued December 31, 2014.

[(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: 42-5E

JANUARY 2015 THROUGH DECEMBER 2015

O&M ACTIVITIES

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Monthly Data | | | | | | | | | | | | | Method of Classification | | |
| | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount | Energy | CP Demand | GCP Demand |
| 1. Description of O&M Activities | | | | | | | | | | | | | | | | |
| 1 - Air Operating Permit Fees | $22,870 | $23,370 | $180,834 | $37,773 | $37,773 | $38,270 | $37,365 | $37,365 | $37,365 | $37,365 | $37,365 | $37,365 | $565,078 | $565,078 | | |
| 3a - Continuous Emission Monitoring Systems | $124,252 | $11,202 | $35,748 | $69,141 | $10,510 | $23,153 | $148,600 | $63,041 | $56,908 | $52,481 | $52,514 | $88,091 | $735,641 | $735,641 | | |
| 5a - Maintenance of Stationary Above Ground Fuel Storage Tanks | $2,034 | $298,957 | $224,092 | $325,809 | $145,625 | $201,999 | $170,735 | $40,282 | $387,406 | $176,866 | $117,577 | $169,686 | $2,261,068 | | $2,261,068 | |
| 8a - Oil Spill Clean-up/Response Equipment | $13,532 | $8,825 | $9,550 | $16,604 | $13,036 | $22,758 | $15,866 | $16,907 | $21,766 | $11,765 | $41,209 | $12,692 | $204,509 | $204,509 | | |
| 13 - RCRA (Resource Conservation & Recovery Act) Corrective Action | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | |
| 14 - NPDES Permit Fees | $80,700 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $80,700 | | $80,700 | |
| 17a - Disposal of Non-Containerized Liquid Waste | $0 | $0 | $2,055 | $0 | $390 | $186 | $0 | $0 | $0 | $0 | $0 | $0 | $2,631 | $2,631 | | |
| 19a - Substation Pollutant Discharge Prevention & Removal - Distribution | $303,564 | $235,402 | $213,907 | $254,873 | $272,499 | $75,601 | $120,000 | $120,000 | $150,000 | $170,000 | $335,000 | $270,000 | $2,520,847 | | | $2,520,847 |
| 19b - Substation Pollutant Discharge Prevention & Removal - Transmission | $195,261 | $112,783 | $129,613 | $7,819 | $53,312 | $246,897 | $50,000 | $50,000 | $50,000 | $100,000 | $135,000 | $170,000 | $1,300,684 | $100,053 | $1,200,632 | |
| 19c - Substation Pollutant Discharge Prevention & Removal - Costs in Base Rates | $0 | $0 | $0 | $0 | $191 | $0 | $0 | ($191) | $0 | $0 | $0 | $0 | $0 | | | |
| NA - Amortization of Gains on Sales of Emissions Allowances | ($19,368) | ($20,874) | ($20,031) | ($20,121) | ($20,121) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | ($241,529) | ($241,529) | | |
| 21 - St. Lucie Turtle Nets | $0 | $0 | $0 | $0 | $0 | $0 | $30,000 | $16,000 | $16,000 | $16,000 | $16,000 | $16,000 | $110,000 | | $110,000 | |
| 22 - Pipeline Integrity Management | $166,166 | $28,985 | $233 | $31,090 | $122,924 | $212,030 | $110,000 | $60,616 | $0 | $63,285 | $30,000 | $29,441 | $854,770 | | $854,770 | |
| 23 - SPCC - Spill Prevention, Control & Countermeasures | $121,926 | ($113,383) | $100,628 | $106,543 | $216,774 | $268,964 | $107,761 | ($375,098) | $75,020 | $81,248 | $89,619 | $248,052 | $928,054 | | $928,054 | |
| 24 - Manatee Reburn | $1,082 | $9,075 | $26,898 | $9,653 | $1,135 | $1,343 | $0 | $0 | $0 | $0 | $284,273 | $0 | $333,459 | $333,459 | | |
| 27 - Lowest Quality Water Source | $10,799 | $10,797 | $11,563 | $11,492 | $10,275 | $9,581 | $11,276 | $12,000 | $12,000 | $12,000 | $12,000 | $11,774 | $135,557 | | $135,557 | |
| 28 - CWA 316(b) Phase II Rule | $6,192 | $15,148 | $7,047 | $11,554 | $15,638 | $33,077 | $84,928 | $101,513 | $122,440 | $110,666 | $81,775 | $81,775 | $671,754 | | $671,754 | |
| 29 - SCR Consumables | $42,587 | $180,683 | $69,052 | $46,125 | $48,881 | $11,976 | $32,097 | $32,097 | $32,097 | $32,982 | $34,963 | $23,012 | $586,552 | $586,552 | | |
| 30 - HBMP | $2,237 | $0 | $4,473 | $0 | $4,473 | $2,237 | $2,237 | $2,237 | $8,602 | $336 | $335 | $335 | $27,500 | | $27,500 | |
| 31 - Clean Air Interstate Rule (CAIR) Compliance | $937,990 | $470,235 | $291,626 | $293,740 | $404,672 | $336,015 | $395,308 | ($14,451) | $408,835 | $388,723 | $386,188 | $386,402 | $4,685,283 | $4,685,283 | | |
| 33 - MATS Project | $211,306 | $229,999 | $118,093 | $256,814 | $244,156 | $218,220 | $276,715 | $244,073 | $212,073 | $212,073 | $212,073 | $212,073 | $2,647,668 | $2,647,668 | | |
| 35 - Martin Plant Drinking Water System Compliance | $3,041 | $2,650 | $0 | $5,300 | $143 | $10,275 | $2,650 | $29,650 | $3,000 | $2,650 | $2,650 | $3,000 | $65,009 | | $65,009 | |
| 37 - DeSoto Next Generation Solar Energy Center | $74,342 | $59,740 | $99,292 | $57,524 | $85,570 | $47,548 | $150,589 | $128,141 | $94,953 | $90,472 | $87,490 | $91,605 | $1,067,268 | | $1,067,268 | |
| 38 - Space Coast Next Generation Solar Energy Center | $20,739 | $7,674 | $15,570 | $15,362 | $15,788 | $24,173 | $30,754 | $23,780 | $33,566 | $24,092 | $22,780 | $34,803 | $269,081 | | $269,081 | |
| 39 - Martin Next Generation Solar Energy Center | $340,095 | $280,950 | $352,453 | $351,255 | $279,373 | $347,834 | $292,954 | $279,436 | $286,195 | $286,195 | $284,418 | $292,954 | $3,674,111 | | $3,674,111 | |
| 40 - Greenhouse Gas Reduction Program | $4,432 | $0 | $0 | $0 | $0 | $0 | $4,420 | $0 | $50,000 | $0 | $20,000 | $0 | $78,852 | $78,852 | | |
| 41 - Manatee Temporary Heating System | $12,581 | $28,064 | $16,170 | $35,160 | $38,180 | $61,105 | $5,258 | $31,468 | $8,800 | $17,800 | $17,300 | $23,800 | $295,687 | $295,687 | | |
| 42 - Turkey Point Cooling Canal Monitoring Plan | $125,136 | $2,565,560 | $2,166,448 | $1,413,817 | $2,712,564 | $3,609,042 | $3,412,685 | $5,699,562 | $9,514,723 | $8,378,138 | $1,440,906 | $370,000 | $41,408,582 | $41,408,582 | | |
| 45 - 800 MW Unit ESP | $35,026 | $81,952 | $66,227 | $63,789 | $92,685 | $71,253 | $94,415 | $108,154 | $107,058 | $127,321 | $138,904 | $93,603 | $1,080,389 | $1,080,389 | | |
| 46 - St. Lucie Cooling Water Discharge Monitoring | $28,902 | $0 | $0 | $22,797 | $0 | $52,848 | $8,380 | $0 | $0 | $0 | $0 | $0 | $112,928 | | $112,928 | |
| 47 - NPDES Permit Renewal Requirements | $4,092 | $21,062 | $4,770 | $2,177 | $6,525 | $5,103 | $2,135 | $2,050 | $9,386 | $5,512 | $6,300 | $0 | $69,110 | | $69,110 | |
| 48 - Industrial Boiler MACT | $0 | $0 | $0 | $0 | $0 | $4,496 | $0 | $0 | $0 | $0 | $0 | $6,000 | $10,496 | | $10,496 | |
| 49 - Thermal Discharge Standards | $15,704 | $4,180 | $6,044 | $6,970 | $9,772 | $13,911 | $93 | $0 | $0 | $13,258 | $0 | $0 | $69,931 | | $69,931 | |
| 50 - Steam Electric Effluent Guidelines Revised Rules | $71,025 | $91,724 | $7,926 | $24,170 | $41,394 | $59,235 | $12,460 | $12,460 | $37,460 | $12,460 | $12,460 | $12,460 | $395,234 | | $395,234 | |
| 51 - Gopher Tortoise Relocations | $0 | $0 | $0 | $0 | $0 | $0 | $15,000 | $20,000 | $7,000 | $15,000 | $0 | $2,000 | $59,000 | | $59,000 | |
| 52 - Numeric Nutrient Criteria Water Quality Standards in Florida | $0 | $0 | $0 | $0 | $0 | $0 | $20,000 | $9,000 | $9,000 | $0 | $0 | $0 | $38,000 | | $38,000 | |
| 2. Total of O&M Activities | $2,958,247 | $4,644,759 | $4,140,284 | $3,457,231 | $4,864,137 | $5,988,984 | $5,624,536 | $6,729,947 | $11,731,508 | $10,418,543 | $3,878,954 | $2,666,776 | $67,103,906 | $52,482,856 | $12,100,203 | $2,520,847 |

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

FORM: 42-5E

JANUARY 2015 THROUGH DECEMBER 2015

O&M ACTIVITIES

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
| 2. Total of O&M Activities | $2,958,247 | $4,644,759 | $4,140,284 | $3,457,231 | $4,864,137 | $5,988,984 | $5,624,536 | $6,729,947 | $11,731,508 | $10,418,543 | $3,878,954 | $2,666,776 | $67,103,906 |
| 3. Recoverable Costs Allocated to Energy | $1,526,448 | $3,596,765 | $2,972,641 | $2,223,097 | $3,587,970 | $4,392,169 | $4,406,431 | $6,201,910 | $10,433,326 | $9,246,195 | $2,655,934 | $1,239,968 | $52,482,856 |
| 4a. Recoverable Costs Allocated to CP Demand | $1,128,235 | $812,591 | $953,736 | $979,261 | $1,003,572 | $1,521,214 | $1,098,105 | $408,133 | $1,148,182 | $1,002,348 | $888,020 | $1,156,807 | $12,100,203 |
| 4b. Recoverable Costs Allocated to GCP Demand | $303,564 | $235,402 | $213,907 | $254,873 | $272,595 | $75,601 | $120,000 | $119,904 | $150,000 | $170,000 | $335,000 | $270,000 | $2,520,847 |
| 5. Retail Energy Jurisdictional Factor | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | |
| 6a. Retail CP Demand Jurisdictional Factor | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | |
| 6b. Retail GCP 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 Energy Recoverable Costs | $1,454,111 | $3,426,318 | $2,831,770 | $2,117,746 | $3,417,939 | $4,184,027 | $4,197,613 | $5,908,006 | $9,938,899 | $8,808,025 | $2,530,072 | $1,181,207 | $49,995,735 |
| 8a. Jurisdictional CP Demand Recoverable Costs | $1,067,829 | $769,085 | $902,672 | $926,831 | $949,841 | $1,439,768 | $1,039,312 | $386,281 | $1,086,708 | $948,682 | $840,475 | $1,094,872 | $11,452,356 |
| 8b. Jurisdictional GCP Demand Recoverable Costs | $303,564 | $235,402 | $213,907 | $254,873 | $272,595 | $75,601 | $120,000 | $119,904 | $150,000 | $170,000 | $335,000 | $270,000 | $2,520,847 |
| 9. Total Jurisdictional Recoverable Costs for O&M Activities | $2,825,504 | $4,430,805 | $3,948,350 | $3,299,451 | $4,640,375 | $5,699,397 | $5,356,926 | $6,414,191 | $11,175,607 | $9,926,707 | $3,705,546 | $2,546,079 | $63,968,938 |

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

FORM: 42-6E

JANUARY 2015 THROUGH DECEMBER 2015

VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| PROJECT # | ECRC - 2015 Actual/Estimated [a] | ECRC - 2015 Original Projection [b] | Dif. ECRC - 2015 Original Projection [c] | % Dif. ECRC - 2015 Original Projection [d] |
| 1. Description of Investment Projects | | | | |
| 2 - Low NOX Burner Technology | $107,156 | $107,387 | ($232) | (0.2%) |
| 3b - Continuous Emission Monitoring Systems | $495,136 | $531,466 | ($36,329) | (6.8%) |
| 4b - Clean Closure Equivalency | $1,177 | $1,181 | ($4) | (0.3%) |
| 5b - Maintenance of Stationary Above Ground Fuel Storage Tanks | $1,391,594 | $1,430,304 | ($38,710) | (2.7%) |
| 7 - Relocate Turbine Lube Oil Underground Piping to Above Ground | $1,312 | $1,315 | ($3) | (0.2%) |
| 8b - Oil Spill Clean-up/Response Equipment | $130,394 | $154,106 | ($23,712) | (15.4%) |
| 10 - Relocate Storm Water Runoff | $7,487 | $7,516 | ($30) | (0.4%) |
| 12 - Scherer Discharge Pipeline | $49,121 | $49,283 | ($162) | (0.3%) |
| 20 - Wastewater Discharge Elimination & Reuse | $79,179 | $79,506 | ($327) | (0.4%) |
| NA - Amortization of Gains on Sales of Emissions Allowances | ($13,099) | ($13,120) | $21 | (0.2%) |
| 21 - St. Lucie Turtle Nets | $769,264 | $876,742 | ($107,478) | (12.3%) |
| 22 - Pipeline Integrity Management | $315,202 | $356,700 | ($41,498) | (11.6%) |
| 23 - SPCC - Spill Prevention, Control & Countermeasures | $1,502,177 | $1,672,980 | ($170,803) | (10.2%) |
| 24 - Manatee Reburn | $3,126,026 | $3,155,836 | ($29,810) | (0.9%) |
| 25 - Pt. Everglades ESP Technology | $18,267,374 | $18,277,851 | ($10,477) | (0.1%) |
| 26 - UST Remove/Replacement | $9,127 | $9,164 | ($37) | (0.4%) |
| 31 - Clean Air Interstate Rule (CAIR) Compliance | $57,856,437 | $58,512,128 | ($655,691) | (1.1%) |
| 33 - MATS Project | $11,502,385 | $11,555,371 | ($52,986) | (0.5%) |
| 35 - Martin Plant Drinking Water System Compliance | $24,140 | $24,247 | ($106) | (0.4%) |
| 36 - Low-Level Radioactive Waste Storage | $1,845,695 | $1,886,196 | ($40,501) | (2.1%) |
| 37 - DeSoto Next Generation Solar Energy Center | $15,885,453 | $15,932,324 | ($46,871) | (0.3%) |
| 38 - Space Coast Next Generation Solar Energy Center | $7,481,609 | $7,509,990 | ($28,381) | (0.4%) |
| 39 - Martin Next Generation Solar Energy Center | $46,046,652 | $46,334,921 | ($288,268) | (0.6%) |
| 41 - Manatee Temporary Heating System | $488,135 | $488,433 | ($299) | (0.1%) |
| 42 - Turkey Point Cooling Canal Monitoring Plan | $694,923 | $437,525 | $257,399 | 58.8% |
| 44 - Martin Plant Barley Barber Swamp Iron Mitigation | $17,619 | $17,697 | ($78) | (0.4%) |
| 45 - 800 MW Unit ESP | $24,703,053 | $24,133,364 | $569,690 | 2.4% |
| 2. Total Investment Projects - Recoverable Costs | $192,784,728 | $193,530,414 | ($745,686) | (0.4%) |

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

[b] The approved projected amount in accordance with FPSC Order No. PSC-14-0643-FOF-EI issued November 4, 2014 and Order No. PSC-14-0714-FOF-EI issued December 31, 2014.

[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: 42-6E

JANUARY 2015 THROUGH DECEMBER 2015

VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| | ECRC - 2015 Actual/Estimated | ECRC - 2015 Original Projection | Dif. ECRC - 2015 Original Projection | % Dif. ECRC - 2015 Original Projection |
| 2. Total Investment Projects - Recoverable Costs | $192,784,728 | $193,530,414 | ($745,686) | (0.4%) |
| 3. Recoverable Costs Allocated to Energy | $33,219,628 | $33,391,723 | ($172,094) | (0.5%) |
| 4. Recoverable Costs Allocated to Demand | $159,565,100 | $160,138,692 | ($573,592) | (0.4%) |
| 7. Jurisdictional Energy Recoverable Costs | $31,645,377 | $31,809,316 | ($163,940) | (0.5%) |
| 8. Jurisdictional Demand Recoverable Costs | $151,021,953 | $151,564,832 | ($542,880) | (0.4%) |
| 9. Total Jurisdictional Recoverable Costs for Investment Projects | $182,667,329 | $183,374,149 | ($706,820) | (0.4%) |

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

FORM: 42-7E

JANUARY 2015 THROUGH DECEMBER 2015

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Monthly Data | | | | | | | | | | | | | Method of Classification | |
| | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount | Energy | Demand |
| 1. Description of Investment Projects [a] | | | | | | | | | | | | | | | |
| 2 - Low NOX Burner Technology | $9,180 | $9,138 | $9,096 | $9,054 | $9,012 | $8,970 | $8,888 | $8,847 | $8,805 | $8,763 | $8,722 | $8,680 | $107,156 | $107,156 | |
| 3b - Continuous Emission Monitoring Systems | $40,997 | $41,613 | $41,713 | $41,570 | $41,428 | $41,286 | $40,888 | $40,747 | $40,606 | $40,465 | $41,430 | $42,394 | $495,136 | $495,136 | |
| 4b - Clean Closure Equivalency | $100 | $100 | $99 | $99 | $99 | $99 | $98 | $97 | $97 | $97 | $96 | $96 | $1,177 | $91 | $1,087 |
| 5b - Maintenance of Stationary Above Ground Fuel Storage Tanks | $77,869 | $77,727 | $77,582 | $105,472 | $133,322 | $133,074 | $131,703 | $131,458 | $131,213 | $130,969 | $130,724 | $130,480 | $1,391,594 | $107,046 | $1,284,548 |
| 7 - Relocate Turbine Lube Oil Underground Piping to Above Ground | $112 | $112 | $111 | $111 | $110 | $110 | $109 | $108 | $108 | $107 | $107 | $106 | $1,312 | $101 | $1,211 |
| 8b - Oil Spill Clean-up/Response Equipment | $10,753 | $10,590 | $10,549 | $10,580 | $10,548 | $10,860 | $11,161 | $11,117 | $11,040 | $10,964 | $10,838 | $11,395 | $130,394 | $10,030 | $120,364 |
| 10 - Relocate Storm Water Runoff | $634 | $633 | $631 | $630 | $628 | $627 | $621 | $619 | $618 | $617 | $615 | $614 | $7,487 | $576 | $6,911 |
| 12 - Scherer Discharge Pipeline | $4,178 | $4,165 | $4,152 | $4,139 | $4,126 | $4,113 | $4,073 | $4,060 | $4,048 | $4,035 | $4,022 | $4,010 | $49,121 | $3,779 | $45,343 |
| 20 - Wastewater Discharge Elimination & Reuse | $6,698 | $6,685 | $6,672 | $6,658 | $6,645 | $6,632 | $6,564 | $6,551 | $6,538 | $6,525 | $6,512 | $6,499 | $79,179 | $6,091 | $73,089 |
| NA - Amortization of Gains on Sales of Emissions Allowances | ($1,967) | ($1,809) | ($1,648) | ($1,489) | ($1,332) | ($1,175) | ($1,005) | ($848) | ($692) | ($535) | ($378) | ($221) | ($13,099) | ($13,099) | |
| 21 - St. Lucie Turtle Nets | $38,902 | $66,994 | $66,985 | $66,961 | $66,904 | $66,835 | $66,124 | $66,053 | $65,982 | $65,912 | $65,841 | $65,770 | $769,264 | $59,174 | $710,090 |
| 22 - Pipeline Integrity Management | $26,703 | $26,663 | $26,623 | $26,584 | $26,544 | $26,411 | $26,043 | $26,004 | $25,965 | $25,926 | $25,887 | $25,848 | $315,202 | $24,246 | $290,956 |
| 23 - SPCC - Spill Prevention, Control & Countermeasures | $125,962 | $125,880 | $125,636 | $125,515 | $125,420 | $125,186 | $123,896 | $123,664 | $123,432 | $123,201 | $122,969 | $131,416 | $1,502,177 | $115,552 | $1,386,625 |
| 24 - Manatee Reburn | $264,340 | $263,797 | $263,254 | $262,710 | $262,166 | $261,621 | $258,949 | $258,410 | $257,871 | $257,506 | $257,487 | $257,915 | $3,126,026 | $3,126,026 | |
| 25 - Pt. Everglades ESP Technology | $1,580,894 | $1,570,396 | $1,559,898 | $1,549,400 | $1,538,902 | $1,528,403 | $1,515,868 | $1,505,486 | $1,495,104 | $1,484,723 | $1,474,341 | $1,463,959 | $18,267,374 | $18,267,374 | |
| 26 - UST Remove/Replacement | $772 | $771 | $769 | $768 | $766 | $764 | $757 | $755 | $753 | $752 | $750 | $749 | $9,127 | $702 | $8,425 |
| 31 - Clean Air Interstate Rule (CAIR) Compliance | $4,889,775 | $4,878,719 | $4,870,278 | | $4,853,334 | $4,844,797 | $4,794,814 | $4,786,426 | $4,778,037 | $4,771,123 | $4,765,684 | $4,761,623 | $57,856,437 | $4,450,495 | $53,405,942 |
| 33 - MATS Project | $972,425 | $970,640 | $968,822 | $967,050 | $965,281 | $963,505 | $953,628 | $951,821 | $950,014 | $948,207 | $946,400 | $944,593 | $11,502,385 | $884,799 | $10,617,587 |
| 35 - Martin Plant Drinking Water System Compliance | $2,038 | $2,035 | $2,032 | $2,029 | $2,025 | $2,022 | $2,001 | $1,998 | $1,995 | $1,992 | $1,988 | $1,985 | $24,140 | $1,857 | $22,283 |
| 36 - Low-Level Radioactive Waste Storage | $113,378 | $159,092 | $159,067 | $158,890 | $158,710 | $158,521 | $156,847 | $156,644 | $156,441 | $156,238 | $156,035 | $155,831 | $1,845,695 | $141,977 | $1,703,718 |
| 37 - DeSoto Next Generation Solar Energy Center | $1,346,938 | $1,343,239 | $1,339,590 | $1,335,954 | $1,332,316 | $1,328,836 | $1,316,112 | $1,313,192 | $1,310,598 | $1,308,004 | $1,306,248 | $1,304,427 | $15,885,453 | $1,221,958 | $14,663,495 |
| 38 - Space Coast Next Generation Solar Energy Center | $634,724 | $633,050 | $631,376 | $629,696 | $627,938 | $626,346 | $620,439 | $618,863 | $617,198 | $615,533 | $613,993 | $612,452 | $7,481,609 | $575,508 | $6,906,100 |
| 39 - Martin Next Generation Solar Energy Center | $3,909,350 | $3,894,705 | $3,884,838 | $3,875,079 | $3,865,361 | $3,855,417 | $3,817,907 | $3,808,119 | $3,798,398 | $3,788,716 | $3,779,034 | $3,769,730 | $46,046,652 | $3,542,050 | $42,504,602 |
| 41 - Manatee Temporary Heating System | $42,234 | $41,955 | $41,677 | $41,399 | $41,120 | $40,842 | $40,506 | $40,231 | $39,956 | $39,680 | $39,405 | $39,130 | $488,135 | $37,549 | $450,586 |
| 42 - Turkey Point Cooling Canal Monitoring Plan | $33,714 | $36,548 | $39,447 | $42,291 | $43,042 | $52,935 | $64,136 | $68,760 | $75,300 | $79,367 | $79,542 | $79,841 | $694,923 | $53,456 | $641,468 |
| 44 - Martin Plant Barley Barber Swamp Iron Mitigation | $1,487 | $1,485 | $1,483 | $1,480 | $1,478 | $1,476 | $1,461 | $1,458 | $1,456 | $1,454 | $1,452 | $1,449 | $17,619 | | $17,619 |
| 45 - 800 MW Unit ESP | $2,046,811 | $2,046,491 | $2,066,885 | $2,085,621 | $2,082,722 | $2,079,305 | $2,057,903 | $2,054,309 | $2,050,715 | $2,047,452 | $2,044,208 | $2,040,632 | $24,703,053 | | $24,703,053 |
| 2. Total Investment Projects - Recoverable Costs | $16,179,003 | $16,211,413 | $16,197,618 | $16,210,079 | $16,198,617 | $16,167,819 | $16,020,489 | $15,984,949 | $15,951,597 | $15,917,791 | $15,883,952 | $15,861,402 | $192,784,728 | $33,219,628 | $159,565,100 |

[a] Each project's Total System Recoverable Expenses 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

FORM: 42-7E

JANUARY 2015 THROUGH DECEMBER 2015

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
| 2. Total Investment Projects - Recoverable Costs | $16,179,003 | $16,211,413 | $16,197,618 | $16,210,079 | $16,198,617 | $16,167,819 | $16,020,489 | $15,984,949 | $15,951,597 | $15,917,791 | $15,883,952 | $15,861,402 | $192,784,728 |
| 3. Recoverable Costs Allocated to Energy | $2,834,772 | $2,827,774 | $2,815,155 | $2,804,455 | $2,793,578 | $2,781,254 | $2,757,244 | $2,744,683 | $2,732,290 | $2,719,997 | $2,709,040 | $2,699,388 | $33,219,628 |
| 4. Recoverable Costs Allocated to Demand | $13,344,231 | $13,383,639 | $13,382,463 | $13,405,624 | $13,405,038 | $13,386,565 | $13,263,245 | $13,240,266 | $13,219,308 | $13,197,795 | $13,174,912 | $13,162,014 | $159,565,100 |
| 5. Retail Energy Jurisdictional Factor | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | |
| 6. Retail Demand Jurisdictional Factor | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | |
| 7. Jurisdictional Energy Recoverable Costs [a] | $2,700,434 | $2,693,768 | $2,681,747 | $2,671,554 | $2,661,193 | $2,649,452 | $2,626,581 | $2,614,614 | $2,602,809 | $2,591,098 | $2,580,661 | $2,571,466 | $31,645,377 |
| 8. Jurisdictional Demand Recoverable Costs [b] | $12,629,778 | $12,667,076 | $12,665,964 | $12,687,884 | $12,687,330 | $12,669,846 | $12,553,128 | $12,531,380 | $12,511,543 | $12,491,182 | $12,469,524 | $12,457,317 | $151,021,953 |
| 9. Total Jurisdictional Recoverable Costs for Investment Projects | $15,330,212 | $15,360,844 | $15,347,710 | $15,359,439 | $15,348,523 | $15,319,298 | $15,179,709 | $15,145,994 | $15,114,352 | $15,082,280 | $15,050,185 | $15,028,783 | $182,667,329 |

[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: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2 - Low NOX Burner Technology** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | N/A |
| 3. Less: Accumulated Depreciation | $2,072,731 | $2,078,071 | $2,083,412 | $2,088,752 | $2,094,092 | $2,099,433 | $2,104,773 | $2,110,113 | $2,115,454 | $2,120,794 | $2,126,134 | $2,131,475 | $2,136,815 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $490,646 | $485,305 | $479,965 | $474,625 | $469,284 | $463,944 | $458,603 | $453,263 | $447,923 | $442,582 | $437,242 | $431,902 | $426,561 | N/A |
| 6. Average Net Investment | | $487,975 | $482,635 | $477,295 | $471,954 | $466,614 | $461,274 | $455,933 | $450,593 | $445,253 | $439,912 | $434,572 | $429,231 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $3,240 | $3,204 | $3,169 | $3,133 | $3,098 | $3,063 | $2,982 | $2,947 | $2,912 | $2,877 | $2,842 | $2,807 | $36,272 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $600 | $593 | $587 | $580 | $574 | $567 | $566 | $560 | $553 | $546 | $540 | $533 | $6,799 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $64,084 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $9,180 | $9,138 | $9,096 | $9,054 | $9,012 | $8,970 | $8,888 | $8,847 | $8,805 | $8,763 | $8,722 | $8,680 | $107,156 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **3b - Continuous Emission Monitoring Systems** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | ($65,369) | $66,897 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $222,546 | $0 | $224,073 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| d. Other | | $6,658 | $5,344 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $12,002 |
| 2. Plant-In-Service/Depreciation Base [a] | $6,159,452 | $6,094,083 | $6,160,980 | $6,160,980 | $6,160,980 | $6,160,980 | $6,160,980 | $6,160,980 | $6,160,980 | $6,160,980 | $6,160,980 | $6,383,526 | $6,383,526 | N/A |
| 3. Less: Accumulated Depreciation | $3,102,610 | $3,126,564 | $3,149,999 | $3,168,091 | $3,186,182 | $3,204,274 | $3,222,366 | $3,240,457 | $3,258,549 | $3,276,640 | $3,294,732 | $3,313,065 | $3,331,638 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $3,056,842 | $2,967,519 | $3,010,980 | $2,992,889 | $2,974,797 | $2,956,706 | $2,938,614 | $2,920,522 | $2,902,431 | $2,884,339 | $2,866,248 | $3,070,461 | $3,051,887 | N/A |
| 6. Average Net Investment | | $3,012,181 | $2,989,250 | $3,001,935 | $2,983,843 | $2,965,751 | $2,947,660 | $2,929,568 | $2,911,477 | $2,893,385 | $2,875,294 | $2,968,354 | $3,061,174 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $19,999 | $19,847 | $19,931 | $19,811 | $19,691 | $19,570 | $19,157 | $19,039 | $18,921 | $18,803 | $19,411 | $20,018 | $234,197 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $3,703 | $3,675 | $3,690 | $3,668 | $3,646 | $3,624 | $3,639 | $3,616 | $3,594 | $3,571 | $3,687 | $3,802 | $43,913 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $17,295 | $18,092 | $18,092 | $18,092 | $18,092 | $18,092 | $18,092 | $18,092 | $18,092 | $18,092 | $18,333 | $18,574 | $217,026 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $40,997 | $41,613 | $41,713 | $41,570 | $41,428 | $41,286 | $40,888 | $40,747 | $40,606 | $40,465 | $41,430 | $42,394 | $495,136 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **4b - Clean Closure Equivalency** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | N/A |
| 3. Less: Accumulated Depreciation | $13,908 | $13,946 | $13,984 | $14,022 | $14,060 | $14,098 | $14,137 | $14,175 | $14,213 | $14,251 | $14,289 | $14,327 | $14,365 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $7,892 | $7,853 | $7,815 | $7,777 | $7,739 | $7,701 | $7,663 | $7,625 | $7,586 | $7,548 | $7,510 | $7,472 | $7,434 | N/A |
| 6. Average Net Investment | | $7,872 | $7,834 | $7,796 | $7,758 | $7,720 | $7,682 | $7,644 | $7,605 | $7,567 | $7,529 | $7,491 | $7,453 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $52 | $52 | $52 | $52 | $51 | $51 | $50 | $50 | $49 | $49 | $49 | $49 | $606 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $10 | $10 | $10 | $10 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $114 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $458 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $100 | $100 | $99 | $99 | $99 | $99 | $98 | $97 | $97 | $97 | $96 | $96 | $1,177 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **5b - Maintenance of Stationary Above Ground Fuel Storage Tanks** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $517 | $3,990 | $0 | $5,838,012 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $5,842,520 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $10,055,195 | $10,055,713 | $10,059,703 | $10,059,703 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | N/A |
| 3. Less: Accumulated Depreciation | $2,843,948 | $2,865,156 | $2,886,371 | $2,907,593 | $2,933,923 | $2,965,361 | $2,996,800 | $3,028,238 | $3,059,676 | $3,091,115 | $3,122,553 | $3,153,992 | $3,185,430 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $7,211,247 | $7,190,557 | $7,173,331 | $7,152,110 | $12,963,792 | $12,932,354 | $12,900,916 | $12,869,477 | $12,838,039 | $12,806,600 | $12,775,162 | $12,743,724 | $12,712,285 | N/A |
| 6. Average Net Investment | | $7,200,902 | $7,181,944 | $7,162,721 | $10,057,951 | $12,948,073 | $12,916,635 | $12,885,196 | $12,853,758 | $12,822,320 | $12,790,881 | $12,759,443 | $12,728,004 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $47,809 | $47,683 | $47,556 | $66,778 | $85,966 | $85,758 | $84,261 | $84,055 | $83,850 | $83,644 | $83,439 | $83,233 | $884,031 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $8,852 | $8,829 | $8,805 | $12,364 | $15,917 | $15,878 | $16,003 | $15,964 | $15,925 | $15,886 | $15,847 | $15,808 | $166,080 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $21,208 | $21,215 | $21,222 | $26,330 | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $341,482 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $77,869 | $77,727 | $77,582 | $105,472 | $133,322 | $133,074 | $131,703 | $131,458 | $131,213 | $130,969 | $130,724 | $130,480 | $1,391,594 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **7 - Relocate Turbine Lube Oil Underground Piping to Above Ground** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $24,622 | $24,684 | $24,746 | $24,808 | $24,871 | $24,933 | $24,995 | $25,057 | $25,119 | $25,181 | $25,243 | $25,305 | $25,367 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $6,408 | $6,346 | $6,284 | $6,222 | $6,159 | $6,097 | $6,035 | $5,973 | $5,911 | $5,849 | $5,787 | $5,725 | $5,663 | N/A |
| 6. Average Net Investment | | $6,377 | $6,315 | $6,253 | $6,190 | $6,128 | $6,066 | $6,004 | $5,942 | $5,880 | $5,818 | $5,756 | $5,694 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $42 | $42 | $42 | $41 | $41 | $40 | $39 | $39 | $38 | $38 | $38 | $37 | $477 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $8 | $8 | $8 | $8 | $8 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $89 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $745 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $112 | $112 | $111 | $111 | $110 | $110 | $109 | $108 | $108 | $107 | $107 | $106 | $1,312 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **8b - Oil Spill Clean-up/Response Equipment** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | ($2,831) | $0 | $0 | $2,291 | $0 | $38,832 | $0 | $0 | ($3,883) | $0 | ($13,867) | $56,000 | $76,542 |
| c. Retirements | | ($48,899) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($3,883) | $0 | ($13,867) | $0 | ($66,650) |
| d. Other | | $2,899 | $0 | $0 | $99 | $0 | $929 | $0 | $0 | $0 | $0 | $0 | $0 | $3,927 |
| 2. Plant-In-Service/Depreciation Base [a] | $781,095 | $778,263 | $778,263 | $778,263 | $780,555 | $780,555 | $819,387 | $819,387 | $819,387 | $815,504 | $815,504 | $801,637 | $857,637 | N/A |
| 3. Less: Accumulated Depreciation | $127,974 | $87,440 | $92,614 | $97,788 | $103,125 | $108,363 | $114,735 | $120,435 | $126,135 | $127,919 | $133,555 | $125,241 | $131,178 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $653,120 | $690,824 | $685,649 | $680,475 | $677,430 | $672,192 | $704,653 | $698,953 | $693,252 | $687,585 | $681,949 | $676,396 | $726,459 | N/A |
| 6. Average Net Investment | | $671,972 | $688,236 | $683,062 | $678,953 | $674,811 | $688,422 | $701,803 | $696,102 | $690,419 | $684,767 | $679,173 | $701,428 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $4,461 | $4,569 | $4,535 | $4,508 | $4,480 | $4,571 | $4,589 | $4,552 | $4,515 | $4,478 | $4,441 | $4,587 | $54,287 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $826 | $846 | $840 | $835 | $830 | $846 | $872 | $865 | $857 | $850 | $844 | $871 | $10,181 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $5,465 | $5,174 | $5,174 | $5,238 | $5,238 | $5,443 | $5,700 | $5,700 | $5,668 | $5,635 | $5,553 | $5,937 | $65,926 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $10,753 | $10,590 | $10,549 | $10,580 | $10,548 | $10,860 | $11,161 | $11,117 | $11,040 | $10,964 | $10,838 | $11,395 | $130,394 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **10 - Relocate Storm Water Runoff** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $59,587 | $59,763 | $59,940 | $60,117 | $60,293 | $60,470 | $60,647 | $60,824 | $61,000 | $61,177 | $61,354 | $61,530 | $61,707 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $58,207 | $58,030 | $57,854 | $57,677 | $57,500 | $57,324 | $57,147 | $56,970 | $56,794 | $56,617 | $56,440 | $56,264 | $56,087 | N/A |
| 6. Average Net Investment | | $58,119 | $57,942 | $57,765 | $57,589 | $57,412 | $57,235 | $57,059 | $56,882 | $56,705 | $56,529 | $56,352 | $56,175 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $386 | $385 | $384 | $382 | $381 | $380 | $373 | $372 | $371 | $370 | $369 | $367 | $4,519 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $71 | $71 | $71 | $71 | $71 | $70 | $71 | $71 | $70 | $70 | $70 | $70 | $847 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $2,120 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $634 | $633 | $631 | $630 | $628 | $627 | $621 | $619 | $618 | $617 | $615 | $614 | $7,487 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **12 - Scherer Discharge Pipeline** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $530,040 | $531,672 | $533,304 | $534,937 | $536,569 | $538,201 | $539,834 | $541,466 | $543,098 | $544,731 | $546,363 | $547,995 | $549,628 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $324,284 | $322,652 | $321,019 | $319,387 | $317,755 | $316,122 | $314,490 | $312,858 | $311,225 | $309,593 | $307,961 | $306,328 | $304,696 | N/A |
| 6. Average Net Investment | | $323,468 | $321,835 | $320,203 | $318,571 | $316,938 | $315,306 | $313,674 | $312,041 | $310,409 | $308,777 | $307,144 | $305,512 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $2,148 | $2,137 | $2,126 | $2,115 | $2,104 | $2,093 | $2,051 | $2,041 | $2,030 | $2,019 | $2,009 | $1,998 | $24,870 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $398 | $396 | $394 | $392 | $390 | $388 | $390 | $388 | $386 | $384 | $381 | $379 | $4,663 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $19,588 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $4,178 | $4,165 | $4,152 | $4,139 | $4,126 | $4,113 | $4,073 | $4,060 | $4,048 | $4,035 | $4,022 | $4,010 | $49,121 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **20 - Wastewater Discharge Elimination & Reuse** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $131,984 | $133,656 | $135,328 | $136,999 | $138,671 | $140,343 | $142,015 | $143,686 | $145,358 | $147,030 | $148,702 | $150,373 | $152,045 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $639,593 | $637,921 | $636,249 | $634,577 | $632,906 | $631,234 | $629,562 | $627,890 | $626,219 | $624,547 | $622,875 | $621,203 | $619,532 | N/A |
| 6. Average Net Investment | | $638,757 | $637,085 | $635,413 | $633,742 | $632,070 | $630,398 | $628,726 | $627,055 | $625,383 | $623,711 | $622,039 | $620,368 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $4,241 | $4,230 | $4,219 | $4,208 | $4,197 | $4,185 | $4,111 | $4,101 | $4,090 | $4,079 | $4,068 | $4,057 | $49,784 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $785 | $783 | $781 | $779 | $777 | $775 | $781 | $779 | $777 | $775 | $773 | $770 | $9,335 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $20,061 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $6,698 | $6,685 | $6,672 | $6,658 | $6,645 | $6,632 | $6,564 | $6,551 | $6,538 | $6,525 | $6,512 | $6,499 | $79,179 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **21 - St. Lucie Turtle Nets** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $5,709,717 | $5,860 | $7,022 | $2,650 | $541 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $5,725,790 |
| c. Retirements | | ($352,942) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($352,942) |
| d. Other | | $4,104 | ($274) | ($328) | ($124) | ($25) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $3,353 |
| 2. Plant-In-Service/Depreciation Base [a] | $352,942 | $6,062,659 | $6,068,519 | $6,075,542 | $6,078,191 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | N/A |
| 3. Less: Accumulated Depreciation | ($952,613) | ($1,296,639) | ($1,287,815) | ($1,279,035) | ($1,270,044) | ($1,260,951) | ($1,251,833) | ($1,242,715) | ($1,233,597) | ($1,224,479) | ($1,215,361) | ($1,206,243) | ($1,197,124) | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $1,305,555 | $7,359,298 | $7,356,334 | $7,354,577 | $7,348,235 | $7,339,683 | $7,330,565 | $7,321,447 | $7,312,329 | $7,303,211 | $7,294,093 | $7,284,974 | $7,275,856 | N/A |
| 6. Average Net Investment | | $4,332,427 | $7,357,816 | $7,355,455 | $7,351,406 | $7,343,959 | $7,335,124 | $7,326,006 | $7,316,888 | $7,307,770 | $7,298,652 | $7,289,534 | $7,280,415 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $28,764 | $48,851 | $48,835 | $48,808 | $48,759 | $48,700 | $47,907 | $47,848 | $47,788 | $47,728 | $47,669 | $47,609 | $559,268 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $5,326 | $9,045 | $9,042 | $9,037 | $9,028 | $9,017 | $9,099 | $9,088 | $9,076 | $9,065 | $9,054 | $9,042 | $104,918 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $4,812 | $9,098 | $9,108 | $9,115 | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $105,078 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $38,902 | $66,994 | $66,985 | $66,961 | $66,904 | $66,835 | $66,124 | $66,053 | $65,982 | $65,912 | $65,841 | $65,770 | $769,264 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **22 - Pipeline Integrity Management** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | ($19,256) | $0 | $0 | $0 | $0 | $0 | $0 | ($19,256) |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,892,047 | $2,872,791 | $2,872,791 | $2,872,791 | $2,872,791 | $2,872,791 | $2,872,791 | $2,872,791 | N/A |
| 3. Less: Accumulated Depreciation | $139,106 | $144,167 | $149,228 | $154,289 | $159,350 | $164,411 | $169,456 | $174,483 | $179,510 | $184,538 | $189,565 | $194,593 | $199,620 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $2,752,941 | $2,747,880 | $2,742,819 | $2,737,758 | $2,732,697 | $2,727,636 | $2,703,336 | $2,698,308 | $2,693,281 | $2,688,253 | $2,683,226 | $2,678,199 | $2,673,171 | N/A |
| 6. Average Net Investment | | $2,750,411 | $2,745,350 | $2,740,289 | $2,735,228 | $2,730,167 | $2,715,486 | $2,700,822 | $2,695,795 | $2,690,767 | $2,685,740 | $2,680,712 | $2,675,685 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $18,261 | $18,227 | $18,194 | $18,160 | $18,126 | $18,029 | $17,662 | $17,629 | $17,596 | $17,563 | $17,530 | $17,497 | $214,474 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $3,381 | $3,375 | $3,369 | $3,362 | $3,356 | $3,338 | $3,354 | $3,348 | $3,342 | $3,336 | $3,329 | $3,323 | $40,214 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $5,061 | $5,061 | $5,061 | $5,061 | $5,061 | $5,044 | $5,027 | $5,027 | $5,027 | $5,027 | $5,027 | $5,027 | $60,514 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $26,703 | $26,663 | $26,623 | $26,584 | $26,544 | $26,411 | $26,043 | $26,004 | $25,965 | $25,926 | $25,887 | $25,848 | $315,202 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **23 - SPCC - Spill Prevention, Control & Countermeasures** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $16,971 | $15,272 | ($17,530) | $35,901 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,655,170 | $1,705,785 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| d. Other | | $0 | $0 | $0 | $439 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $439 |
| 2. Plant-In-Service/Depreciation Base [a] | $14,417,942 | $14,434,913 | $14,450,185 | $14,432,655 | $14,468,556 | $14,468,556 | $14,468,556 | $14,468,556 | $14,468,556 | $14,468,556 | $14,468,556 | $14,468,556 | $16,123,727 | N/A |
| 3. Less: Accumulated Depreciation | $2,180,627 | $2,210,348 | $2,240,095 | $2,269,841 | $2,300,068 | $2,329,856 | $2,359,644 | $2,389,432 | $2,419,220 | $2,449,008 | $2,478,796 | $2,508,585 | $2,540,621 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $12,237,315 | $12,224,565 | $12,210,090 | $12,162,815 | $12,168,489 | $12,138,701 | $12,108,913 | $12,079,124 | $12,049,336 | $12,019,548 | $11,989,760 | $11,959,972 | $13,583,106 | N/A |
| 6. Average Net Investment | | $12,230,940 | $12,217,327 | $12,186,452 | $12,165,652 | $12,153,595 | $12,123,807 | $12,094,019 | $12,064,230 | $12,034,442 | $12,004,654 | $11,974,866 | $12,771,539 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $81,205 | $81,115 | $80,910 | $80,772 | $80,692 | $80,494 | $79,087 | $78,892 | $78,698 | $78,503 | $78,308 | $83,518 | $962,192 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $15,035 | $15,019 | $14,981 | $14,955 | $14,940 | $14,904 | $15,021 | $14,984 | $14,947 | $14,910 | $14,873 | $15,862 | $180,431 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $29,721 | $29,747 | $29,745 | $29,788 | $29,788 | $29,788 | $29,788 | $29,788 | $29,788 | $29,788 | $29,788 | $32,036 | $359,555 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $125,962 | $125,880 | $125,636 | $125,515 | $125,420 | $125,186 | $123,896 | $123,664 | $123,432 | $123,201 | $122,969 | $131,416 | $1,502,177 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **24 - Manatee Reburn** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $458 | $122 | $122 | $0 | $0 | $0 | $0 | $0 | $44,740 | $88,867 | $95,872 | $230,182 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $229,723 | $229,723 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| d. Other | | $0 | $0 | ($16) | ($16) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($33) |
| 2. Plant-In-Service/Depreciation Base [a] | $31,964,179 | $31,964,179 | $31,964,179 | $31,964,179 | $31,964,179 | $31,964,179 | $31,964,179 | $31,964,179 | $31,964,179 | $31,964,179 | $31,964,179 | $31,964,179 | $32,193,902 | N/A |
| 3. Less: Accumulated Depreciation | $7,137,302 | $7,206,558 | $7,275,813 | $7,345,053 | $7,414,292 | $7,483,547 | $7,552,803 | $7,622,059 | $7,691,315 | $7,760,570 | $7,829,826 | $7,899,082 | $7,968,586 | N/A |
| 4. CWIP - Non Interest Bearing | $445 | $445 | $904 | $1,026 | $1,148 | $1,148 | $1,148 | $1,148 | $1,148 | $1,148 | $45,888 | $134,755 | $904 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $24,827,322 | $24,758,067 | $24,689,269 | $24,620,152 | $24,551,035 | $24,481,780 | $24,412,524 | $24,343,268 | $24,274,012 | $24,204,757 | $24,180,241 | $24,199,852 | $24,226,220 | N/A |
| 6. Average Net Investment | | $24,792,694 | $24,723,668 | $24,654,711 | $24,585,594 | $24,516,407 | $24,447,152 | $24,377,896 | $24,308,640 | $24,239,385 | $24,192,499 | $24,190,047 | $24,213,036 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $164,607 | $164,148 | $163,690 | $163,232 | $162,772 | $162,312 | $159,416 | $158,963 | $158,510 | $158,203 | $158,187 | $158,338 | $1,932,378 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $30,478 | $30,393 | $30,308 | $30,223 | $30,138 | $30,053 | $30,277 | $30,191 | $30,105 | $30,047 | $30,044 | $30,073 | $362,330 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $69,256 | $69,256 | $69,256 | $69,256 | $69,256 | $69,256 | $69,256 | $69,256 | $69,256 | $69,256 | $69,256 | $69,505 | $831,318 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $264,340 | $263,797 | $263,254 | $262,710 | $262,166 | $261,621 | $258,949 | $258,410 | $257,871 | $257,506 | $257,487 | $257,915 | $3,126,026 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **25 - Pt. Everglades ESP Technology** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| d. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2. Plant-In-Service/Depreciation Base [a] | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 3. Less: Accumulated Depreciation | ($32,020,481) | ($30,686,295) | ($29,352,108) | ($28,017,921) | ($26,683,735) | ($25,349,548) | ($24,015,361) | ($22,681,175) | ($21,346,988) | ($20,012,801) | ($18,678,615) | ($17,344,428) | ($16,010,241) | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $32,020,481 | $30,686,295 | $29,352,108 | $28,017,921 | $26,683,735 | $25,349,548 | $24,015,361 | $22,681,175 | $21,346,988 | $20,012,801 | $18,678,615 | $17,344,428 | $16,010,241 | N/A |
| 6. Average Net Investment | | $31,353,388 | $30,019,201 | $28,685,015 | $27,350,828 | $26,016,641 | $24,682,455 | $23,348,268 | $22,014,081 | $20,679,895 | $19,345,708 | $18,011,521 | $16,677,335 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $208,165 | $199,307 | $190,449 | $181,591 | $172,733 | $163,875 | $152,683 | $143,958 | $135,233 | $126,508 | $117,784 | $109,059 | $1,901,344 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $38,543 | $36,903 | $35,262 | $33,622 | $31,982 | $30,342 | $28,999 | $27,341 | $25,684 | $24,027 | $22,370 | $20,713 | $355,790 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $16,010,240 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $1,580,894 | $1,570,396 | $1,559,898 | $1,549,400 | $1,538,902 | $1,528,403 | $1,515,868 | $1,505,486 | $1,495,104 | $1,484,723 | $1,474,341 | $1,463,959 | $18,267,374 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **26 - UST Remove/Replacement** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $42,859 | $43,061 | $43,263 | $43,465 | $43,667 | $43,869 | $44,071 | $44,273 | $44,475 | $44,677 | $44,879 | $45,081 | $45,283 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $72,588 | $72,386 | $72,184 | $71,982 | $71,779 | $71,577 | $71,375 | $71,173 | $70,971 | $70,769 | $70,567 | $70,365 | $70,163 | N/A |
| 6. Average Net Investment | | $72,487 | $72,285 | $72,083 | $71,881 | $71,678 | $71,476 | $71,274 | $71,072 | $70,870 | $70,668 | $70,466 | $70,264 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $481 | $480 | $479 | $477 | $476 | $475 | $466 | $465 | $463 | $462 | $461 | $459 | $5,644 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $89 | $89 | $89 | $88 | $88 | $88 | $89 | $88 | $88 | $88 | $88 | $87 | $1,058 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $2,424 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $772 | $771 | $769 | $768 | $766 | $764 | $757 | $755 | $753 | $752 | $750 | $749 | $9,127 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **31 - Clean Air Interstate Rule (CAIR) Compliance** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $1,463 | $29 | $29 | $2,568 | $0 | $0 | $23,115 | $23,115 | $23,115 | $402,237 | $402,237 | $402,237 | $1,280,144 |
| b. Clearings to Plant | | ($496,026) | $1,230 | $31,822 | $7,922 | $26,258 | $2,225 | $0 | $0 | $0 | $0 | $0 | $1,276,056 | $849,486 |
| c. Retirements | | $0 | ($13,708) | $0 | $0 | ($2,222) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($15,929) |
| d. Other | | ($351) | ($41) | ($1,299) | ($659) | ($78) | ($18) | $0 | $0 | $0 | $0 | $0 | $0 | ($2,446) |
| 2. Plant-In-Service/Depreciation Base [a] | $525,512,958 | $525,016,931 | $525,018,161 | $525,049,983 | $525,057,905 | $525,084,163 | $525,086,388 | $525,086,388 | $525,086,388 | $525,086,388 | $525,086,388 | $525,086,388 | $526,362,444 | N/A |
| 3. Less: Accumulated Depreciation | $43,280,785 | $44,381,974 | $45,469,261 | $46,569,030 | $47,669,481 | $48,768,326 | $49,869,482 | $50,970,658 | $52,071,834 | $53,173,010 | $54,274,187 | $55,375,363 | $56,477,922 | N/A |
| 4. CWIP - Non Interest Bearing | $1,709 | $3,172 | $3,079 | $3,108 | $5,676 | $0 | $0 | $23,115 | $46,230 | $69,345 | $471,582 | $873,819 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $482,233,882 | $480,638,129 | $479,551,980 | $478,484,061 | $477,394,100 | $476,315,837 | $475,216,906 | $474,138,845 | $473,060,784 | $471,982,722 | $471,283,783 | $470,584,844 | $469,884,522 | N/A |
| 6. Average Net Investment | | $481,436,005 | $480,095,054 | $479,018,020 | $477,939,080 | $476,854,968 | $475,766,372 | $474,677,875 | $473,599,814 | $472,521,753 | $471,633,253 | $470,934,313 | $470,234,683 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $3,196,406 | $3,187,503 | $3,180,352 | $3,173,189 | $3,165,991 | $3,158,763 | $3,104,088 | $3,097,038 | $3,089,988 | $3,084,178 | $3,079,608 | $3,075,032 | $37,592,137 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $591,829 | $590,181 | $588,857 | $587,531 | $586,198 | $584,860 | $589,550 | $588,211 | $586,872 | $585,768 | $584,900 | $584,031 | $7,048,788 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,101,540 | $1,101,035 | $1,101,069 | $1,101,110 | $1,101,145 | $1,101,174 | $1,101,176 | $1,101,176 | $1,101,176 | $1,101,176 | $1,101,176 | $1,102,559 | $13,215,512 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $4,889,775 | $4,878,719 | $4,870,278 | $4,861,829 | $4,853,334 | $4,844,797 | $4,794,814 | $4,786,426 | $4,778,037 | $4,771,123 | $4,765,684 | $4,761,623 | $57,856,437 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **33 - MATS Project** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $10,307 | $302 | $2,547 | $12,016 | $2,680 | ($36,769) | $0 | $0 | $0 | $0 | $0 | $0 | ($8,917) |
| b. Clearings to Plant | | $0 | $0 | ($532) | $0 | $0 | $36,805 | $0 | $0 | $0 | $0 | $0 | $0 | $36,273 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $107,184,439 | $107,184,439 | $107,184,439 | $107,183,907 | $107,183,907 | $107,183,907 | $107,220,712 | $107,220,712 | $107,220,712 | $107,220,712 | $107,220,712 | $107,220,712 | $107,220,712 | N/A |
| 3. Less: Accumulated Depreciation | $13,001,650 | $13,233,789 | $13,465,928 | $13,698,067 | $13,930,205 | $14,162,343 | $14,394,521 | $14,626,738 | $14,858,956 | $15,091,174 | $15,323,392 | $15,555,609 | $15,787,827 | N/A |
| 4. CWIP - Non Interest Bearing | $8,918 | $19,225 | $19,527 | $22,074 | $34,090 | $36,770 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $94,191,707 | $93,969,875 | $93,738,038 | $93,507,914 | $93,287,792 | $93,058,334 | $92,826,192 | $92,593,974 | $92,361,756 | $92,129,539 | $91,897,321 | $91,665,103 | $91,432,885 | N/A |
| 6. Average Net Investment | | $94,080,791 | $93,853,956 | $93,622,976 | $93,397,853 | $93,173,063 | $92,942,263 | $92,710,083 | $92,477,865 | $92,245,647 | $92,013,430 | $91,781,212 | $91,548,994 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $624,632 | $623,126 | $621,593 | $620,098 | $618,605 | $617,073 | $606,264 | $604,746 | $603,227 | $601,709 | $600,190 | $598,672 | $7,339,935 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $115,654 | $115,375 | $115,091 | $114,814 | $114,538 | $114,254 | $115,146 | $114,858 | $114,569 | $114,281 | $113,992 | $113,704 | $1,376,274 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $232,139 | $232,139 | $232,138 | $232,138 | $232,138 | $232,178 | $232,218 | $232,218 | $232,218 | $232,218 | $232,218 | $232,218 | $2,786,177 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $972,425 | $970,640 | $968,822 | $967,050 | $965,281 | $963,505 | $953,628 | $951,821 | $950,014 | $948,207 | $946,400 | $944,593 | $11,502,385 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **35 - Martin Plant Drinking Water System Compliance** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $28,483 | $28,895 | $29,307 | $29,719 | $30,131 | $30,543 | $30,955 | $31,367 | $31,779 | $32,191 | $32,603 | $33,015 | $33,427 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $206,908 | $206,496 | $206,084 | $205,672 | $205,260 | $204,848 | $204,436 | $204,024 | $203,612 | $203,200 | $202,789 | $202,377 | $201,965 | N/A |
| 6. Average Net Investment | | $206,702 | $206,290 | $205,878 | $205,466 | $205,054 | $204,642 | $204,230 | $203,818 | $203,406 | $202,995 | $202,583 | $202,171 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $1,372 | $1,370 | $1,367 | $1,364 | $1,361 | $1,359 | $1,336 | $1,333 | $1,330 | $1,327 | $1,325 | $1,322 | $16,166 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $254 | $254 | $253 | $253 | $252 | $252 | $254 | $253 | $253 | $252 | $252 | $251 | $3,031 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $4,943 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $2,038 | $2,035 | $2,032 | $2,029 | $2,025 | $2,022 | $2,001 | $1,998 | $1,995 | $1,992 | $1,988 | $1,985 | $24,140 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **36 - Low-Level Radioactive Waste Storage** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $9,762,840 | $33,652 | $4,828 | $1,313 | $4,064 | ($509) | $0 | $0 | $0 | $0 | $0 | $0 | $9,806,188 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $7,601,405 | $17,364,245 | $17,397,897 | $17,402,725 | $17,404,038 | $17,408,102 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | N/A |
| 3. Less: Accumulated Depreciation | $444,145 | $462,869 | $488,940 | $515,041 | $541,146 | $567,255 | $593,367 | $619,478 | $645,590 | $671,701 | $697,812 | $723,924 | $750,035 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $7,157,260 | $16,901,376 | $16,908,956 | $16,887,684 | $16,862,892 | $16,840,847 | $16,814,226 | $16,788,114 | $16,762,003 | $16,735,892 | $16,709,780 | $16,683,669 | $16,657,557 | N/A |
| 6. Average Net Investment | | $12,029,318 | $16,905,166 | $16,898,320 | $16,875,288 | $16,851,869 | $16,827,536 | $16,801,170 | $16,775,059 | $16,748,947 | $16,722,836 | $16,696,724 | $16,670,613 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $79,866 | $112,239 | $112,193 | $112,040 | $111,885 | $111,723 | $109,869 | $109,698 | $109,527 | $109,357 | $109,186 | $109,015 | $1,296,599 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $14,788 | $20,782 | $20,773 | $20,745 | $20,716 | $20,686 | $20,867 | $20,835 | $20,802 | $20,770 | $20,737 | $20,705 | $243,205 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $18,724 | $26,072 | $26,100 | $26,105 | $26,109 | $26,112 | $26,111 | $26,111 | $26,111 | $26,111 | $26,111 | $26,111 | $305,891 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $113,378 | $159,092 | $159,067 | $158,890 | $158,710 | $158,521 | $156,847 | $156,644 | $156,441 | $156,238 | $156,035 | $155,831 | $1,845,695 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **37 - DeSoto Next Generation Solar Energy Center** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $7,747 | $46,028 | $129,792 | $129,792 | $129,792 | $129,792 | $84,689 | $657,632 |
| b. Clearings to Plant | | ($5,903) | $0 | $358 | ($541) | $52 | $6,787 | $0 | $0 | $0 | $0 | $572,943 | $84,689 | $658,385 |
| c. Retirements | | ($11,335) | $0 | $0 | $0 | $0 | ($10,599) | $0 | $0 | $0 | $0 | $0 | $0 | ($21,935) |
| d. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2. Plant-In-Service/Depreciation Base [a] | $152,995,624 | $152,989,721 | $152,989,721 | $152,990,079 | $152,989,537 | $152,989,590 | $152,996,376 | $152,996,376 | $152,996,376 | $152,996,376 | $152,996,376 | $153,569,320 | $153,654,009 | N/A |
| 3. Less: Accumulated Depreciation | $26,262,552 | $26,676,256 | $27,101,224 | $27,526,194 | $27,951,162 | $28,376,131 | $28,790,556 | $29,215,638 | $29,640,719 | $30,065,801 | $30,490,882 | $30,916,805 | $31,343,686 | N/A |
| 4. CWIP - Non Interest Bearing | $3,803 | $3,803 | $0 | $0 | $0 | $0 | $7,747 | $53,775 | $183,567 | $313,359 | $443,151 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $126,736,874 | $126,317,268 | $125,888,496 | $125,463,885 | $125,038,375 | $124,613,459 | $124,213,567 | $123,834,514 | $123,539,225 | $123,243,935 | $122,948,646 | $122,652,515 | $122,310,322 | N/A |
| 6. Average Net Investment | | $126,527,071 | $126,102,882 | $125,676,191 | $125,251,130 | $124,825,917 | $124,413,513 | $124,024,041 | $123,686,869 | $123,391,580 | $123,096,290 | $122,800,580 | $122,481,419 | N/A |
| a. Average ITC Balance | | $36,314,745 | $36,192,679 | $36,070,613 | $35,948,547 | $35,826,481 | $35,704,415 | $35,582,349 | $35,460,283 | $35,338,217 | $35,216,151 | $35,094,085 | $34,972,019 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $915,290 | $912,221 | $909,135 | $906,060 | $902,984 | $899,993 | $885,556 | $883,096 | $880,909 | $878,722 | $876,533 | $874,190 | $10,724,689 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $167,004 | $166,444 | $165,881 | $165,320 | $164,759 | $164,213 | $165,869 | $165,410 | $165,002 | $164,595 | $164,187 | $163,750 | $1,982,435 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $418,980 | $418,910 | $418,910 | $418,910 | $418,909 | $418,966 | $419,022 | $419,022 | $419,022 | $419,022 | $419,864 | $420,822 | $5,030,361 |
| b. Amortization [e] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Dismantlement [f] | | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $72,708 |
| 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 Expenses (Lines 7 & 8) | | $1,346,938 | $1,343,239 | $1,339,590 | $1,335,954 | $1,332,316 | $1,328,836 | $1,316,112 | $1,313,192 | $1,310,598 | $1,308,004 | $1,306,248 | $1,304,427 | $15,885,453 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **38 - Space Coast Next Generation Solar Energy Center** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $1,374 | $0 | $0 | $0 | $0 | $16,683 | $0 | $0 | $0 | $0 | $0 | $18,057 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | ($9,438) | $8,680 | $16,683 | $0 | $0 | $0 | $14,962 | $0 | $30,887 |
| c. Retirements | | $0 | $0 | $0 | $0 | ($9,438) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($9,438) |
| d. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2. Plant-In-Service/Depreciation Base [a] | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | $70,626,217 | $70,616,778 | $70,625,458 | $70,642,141 | $70,642,141 | $70,642,141 | $70,642,141 | $70,657,104 | $70,657,104 | N/A |
| 3. Less: Accumulated Depreciation | $11,173,475 | $11,371,400 | $11,569,325 | $11,767,250 | $11,965,175 | $12,153,583 | $12,351,422 | $12,549,358 | $12,747,316 | $12,945,274 | $13,143,232 | $13,341,315 | $13,539,522 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $1,374 | $1,374 | $1,374 | $1,374 | $16,337 | $16,337 | $16,337 | $16,337 | $16,337 | $1,374 | $1,374 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $59,452,742 | $59,254,817 | $59,058,266 | $58,860,341 | $58,662,417 | $58,464,570 | $58,290,373 | $58,109,120 | $57,911,162 | $57,713,204 | $57,515,246 | $57,317,163 | $57,118,956 | N/A |
| 6. Average Net Investment | | $59,353,779 | $59,156,541 | $58,959,304 | $58,761,379 | $58,563,493 | $58,377,471 | $58,199,747 | $58,010,141 | $57,812,183 | $57,614,225 | $57,416,205 | $57,218,060 | N/A |
| a. Average ITC Balance | | $15,510,135 | $15,458,946 | $15,407,757 | $15,356,568 | $15,305,379 | $15,254,190 | $15,203,001 | $15,151,812 | $15,100,623 | $15,049,434 | $14,998,245 | $14,947,056 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $426,202 | $424,787 | $423,371 | $421,951 | $420,531 | $419,190 | $412,428 | $411,081 | $409,679 | $408,277 | $406,875 | $405,472 | $4,989,846 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $77,860 | $77,602 | $77,343 | $77,083 | $76,824 | $76,579 | $77,339 | $77,087 | $76,824 | $76,561 | $76,298 | $76,035 | $923,434 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $195,013 | $195,013 | $195,013 | $195,013 | $194,934 | $194,928 | $195,023 | $195,046 | $195,046 | $195,046 | $195,171 | $195,295 | $2,340,541 |
| b. Amortization [e] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Dismantlement [f] | | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $34,944 |
| 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 Expenses (Lines 7 & 8) | | $634,724 | $633,050 | $631,376 | $629,696 | $627,938 | $626,346 | $620,439 | $618,863 | $617,198 | $615,533 | $613,993 | $612,452 | $7,481,609 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **39 - Martin Next Generation Solar Energy Center** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $29,417 | $30,820 | $19,564 | $73,531 | $42,996 | $55,193 | $38,190 | $45,225 | $55,275 | $55,275 | $55,275 | $50,250 | $551,012 |
| b. Clearings to Plant | | ($3,602,914) | $13,752 | $6,909 | $0 | $0 | ($16,011) | $0 | $0 | $0 | $0 | $0 | $290,639 | ($3,307,625) |
| c. Retirements | | ($2,724,034) | ($12,358) | $0 | $0 | $0 | ($21,384) | $0 | $0 | $0 | $0 | $0 | $0 | ($2,757,776) |
| d. Other | | ($932,481) | ($4,152) | ($4,549) | ($6,300) | ($1,235) | ($4,683) | $0 | $0 | $0 | $0 | $0 | $0 | ($953,401) |
| 2. Plant-In-Service/Depreciation Base [a] | $425,643,543 | $422,040,629 | $422,054,381 | $422,061,290 | $422,061,290 | $422,061,290 | $422,045,279 | $422,045,279 | $422,045,279 | $422,045,279 | $422,045,279 | $422,045,279 | $422,335,919 | N/A |
| 3. Less: Accumulated Depreciation | $55,513,258 | $53,054,302 | $54,230,415 | $55,418,518 | $56,604,880 | $57,796,306 | $58,962,730 | $60,155,050 | $61,347,370 | $62,539,690 | $63,732,010 | $64,924,330 | $66,117,050 | N/A |
| 4. CWIP - Non Interest Bearing | $52,382 | $81,800 | $99,355 | $118,919 | $192,451 | $235,447 | $290,639 | $328,829 | $374,054 | $429,329 | $484,604 | $539,879 | $299,490 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $370,182,667 | $369,068,127 | $367,923,321 | $366,761,691 | $365,648,861 | $364,500,431 | $363,373,189 | $362,219,059 | $361,071,964 | $359,934,919 | $358,797,874 | $357,660,828 | $356,518,359 | N/A |
| 6. Average Net Investment | | $369,625,397 | $368,495,724 | $367,342,506 | $366,205,276 | $365,074,646 | $363,936,810 | $362,796,124 | $361,645,511 | $360,503,441 | $359,366,396 | $358,229,351 | $357,089,594 | N/A |
| a. Average ITC Balance | | $106,849,081 | $106,505,283 | $106,161,485 | $105,817,687 | $105,473,889 | $105,130,091 | $104,786,293 | $104,442,495 | $104,098,697 | $103,754,899 | $103,411,101 | $103,067,303 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $2,675,429 | $2,667,217 | $2,658,848 | $2,650,585 | $2,642,366 | $2,634,100 | $2,591,903 | $2,583,659 | $2,575,471 | $2,567,315 | $2,559,159 | $2,550,986 | $31,357,038 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $488,113 | $486,616 | $485,089 | $483,583 | $482,084 | $480,577 | $485,434 | $483,891 | $482,358 | $480,832 | $479,305 | $477,775 | $5,795,657 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,168,712 | $1,163,777 | $1,163,805 | $1,163,815 | $1,163,815 | $1,163,644 | $1,163,473 | $1,163,473 | $1,163,473 | $1,163,473 | $1,163,473 | $1,163,873 | $13,968,805 |
| b. Amortization [e] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Dismantlement [f] | | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $346,164 |
| 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 Expenses (Lines 7 & 8) | | $3,909,350 | $3,894,705 | $3,884,838 | $3,875,079 | $3,865,361 | $3,855,417 | $3,817,907 | $3,808,119 | $3,798,398 | $3,788,716 | $3,779,034 | $3,769,730 | $46,046,652 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **41 - Manatee Temporary Heating System** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | N/A |
| 3. Less: Accumulated Depreciation | $6,394,998 | $6,430,375 | $6,465,752 | $6,501,129 | $6,536,506 | $6,571,883 | $6,607,260 | $6,642,638 | $6,678,015 | $6,713,392 | $6,748,769 | $6,784,146 | $6,819,523 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $889,094 | $853,717 | $818,340 | $782,963 | $747,586 | $712,209 | $676,832 | $641,454 | $606,077 | $570,700 | $535,323 | $499,946 | $464,569 | N/A |
| 6. Average Net Investment | | $871,406 | $836,028 | $800,651 | $765,274 | $729,897 | $694,520 | $659,143 | $623,766 | $588,389 | $553,012 | $517,635 | $482,258 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $5,786 | $5,551 | $5,316 | $5,081 | $4,846 | $4,611 | $4,310 | $4,079 | $3,848 | $3,616 | $3,385 | $3,154 | $53,582 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $1,071 | $1,028 | $984 | $941 | $897 | $854 | $819 | $775 | $731 | $687 | $643 | $599 | $10,028 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $424,525 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $42,234 | $41,955 | $41,677 | $41,399 | $41,120 | $40,842 | $40,506 | $40,231 | $39,956 | $39,680 | $39,405 | $39,130 | $488,135 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **42 - Turkey Point Cooling Canal Monitoring Plan** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $475,098 | $139,823 | $489,883 | $128,862 | $43,605 | $2,081,846 | $453,500 | $561,603 | $867,935 | $30,000 | $30,000 | $56,924 | $5,359,080 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $3,582,753 | $4,057,851 | $4,197,674 | $4,687,557 | $4,816,419 | $4,860,024 | $6,941,871 | $7,395,371 | $7,956,974 | $8,824,909 | $8,854,909 | $8,884,909 | $8,941,833 | N/A |
| 3. Less: Accumulated Depreciation | $261,061 | $266,791 | $272,983 | $279,647 | $286,775 | $294,032 | $302,884 | $313,637 | $325,151 | $337,737 | $350,997 | $364,302 | $377,672 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $3,321,692 | $3,791,059 | $3,924,691 | $4,407,910 | $4,529,644 | $4,565,992 | $6,638,987 | $7,081,734 | $7,631,823 | $8,487,171 | $8,503,912 | $8,520,607 | $8,564,161 | N/A |
| 6. Average Net Investment | | $3,556,375 | $3,857,875 | $4,166,300 | $4,468,777 | $4,547,818 | $5,602,489 | $6,860,360 | $7,356,778 | $8,059,497 | $8,495,541 | $8,512,259 | $8,542,384 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $23,612 | $25,614 | $27,661 | $29,670 | $30,194 | $37,197 | $44,862 | $48,109 | $52,704 | $55,555 | $55,665 | $55,862 | $486,704 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $4,372 | $4,742 | $5,122 | $5,493 | $5,591 | $6,887 | $8,521 | $9,137 | $10,010 | $10,551 | $10,572 | $10,610 | $91,608 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $5,730 | $6,192 | $6,664 | $7,128 | $7,257 | $8,851 | $10,753 | $11,514 | $12,586 | $13,260 | $13,305 | $13,370 | $116,611 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $33,714 | $36,548 | $39,447 | $42,291 | $43,042 | $52,935 | $64,136 | $68,760 | $75,300 | $79,367 | $79,542 | $79,841 | $694,923 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **44 - Martin Plant Barley Barber Swamp Iron Mitigation** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $12,196 | $12,485 | $12,773 | $13,061 | $13,349 | $13,638 | $13,926 | $14,214 | $14,502 | $14,791 | $15,079 | $15,367 | $15,655 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $152,522 | $152,234 | $151,946 | $151,657 | $151,369 | $151,081 | $150,793 | $150,504 | $150,216 | $149,928 | $149,640 | $149,351 | $149,063 | N/A |
| 6. Average Net Investment | | $152,378 | $152,090 | $151,802 | $151,513 | $151,225 | $150,937 | $150,649 | $150,360 | $150,072 | $149,784 | $149,495 | $149,207 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $1,012 | $1,010 | $1,008 | $1,006 | $1,004 | $1,002 | $985 | $983 | $981 | $979 | $978 | $976 | $11,924 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $187 | $187 | $187 | $186 | $186 | $186 | $187 | $187 | $186 | $186 | $186 | $185 | $2,236 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $3,459 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $1,487 | $1,485 | $1,483 | $1,480 | $1,478 | $1,476 | $1,461 | $1,458 | $1,456 | $1,454 | $1,452 | $1,449 | $17,619 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **45 - 800 MW Unit ESP** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $1,267 | $0 | $423 | $0 | $32,157 | $0 | $0 | $0 | $80,400 | $0 | $0 | $114,247 |
| b. Clearings to Plant | | $189,653 | $450,621 | $4,328,586 | $128,691 | $17,222 | $721 | $0 | $0 | $0 | $16,628 | $17,218 | $0 | $5,149,341 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $209,303,741 | $209,493,394 | $209,944,015 | $214,272,601 | $214,401,292 | $214,418,514 | $214,419,235 | $214,419,235 | $214,419,235 | $214,419,235 | $214,435,864 | $214,453,082 | $214,453,082 | N/A |
| 3. Less: Accumulated Depreciation | $6,362,444 | $6,813,416 | $7,265,095 | $7,721,935 | $8,183,586 | $8,645,396 | $9,107,225 | $9,569,055 | $10,030,885 | $10,492,715 | $10,954,563 | $11,416,447 | $11,878,351 | N/A |
| 4. CWIP - Non Interest Bearing | ($0) | ($0) | $1,267 | $1,267 | $1,690 | $1,690 | $33,846 | $33,846 | $33,846 | $33,846 | $97,618 | $80,400 | $80,400 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $202,941,297 | $202,679,977 | $202,680,187 | $206,551,933 | $206,219,395 | $205,774,808 | $205,345,857 | $204,884,027 | $204,422,197 | $203,960,367 | $203,578,919 | $203,117,034 | $202,655,131 | N/A |
| 6. Average Net Investment | | $202,810,637 | $202,680,082 | $204,616,060 | $206,385,664 | $205,997,102 | $205,560,332 | $205,114,942 | $204,653,112 | $204,191,282 | $203,769,643 | $203,347,976 | $202,886,083 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $1,346,524 | $1,345,657 | $1,358,511 | $1,370,260 | $1,367,680 | $1,364,780 | $1,341,320 | $1,338,300 | $1,335,280 | $1,332,522 | $1,329,765 | $1,326,745 | $16,157,343 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $249,315 | $249,155 | $251,535 | $253,710 | $253,232 | $252,695 | $254,753 | $254,179 | $253,606 | $253,082 | $252,558 | $251,985 | $3,029,804 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $450,972 | $451,679 | $456,840 | $461,652 | $461,810 | $461,829 | $461,830 | $461,830 | $461,830 | $461,848 | $461,885 | $461,903 | $5,515,907 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $2,046,811 | $2,046,491 | $2,066,885 | $2,085,621 | $2,082,722 | $2,079,305 | $2,057,903 | $2,054,309 | $2,050,715 | $2,047,452 | $2,044,208 | $2,040,632 | $24,703,053 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[c] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-8E, pages 39-41.

(e) Applicable amortization period(s). See Form 42-8E, pages 39-41.

[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. 2015 actual period of 6.42% reflects a 10.5% return on equity and the monthly Equity Component for the Jul. – Dec. 2015 estimated period of 6.36% reflects a 10.5% return on equity.

Debt Component: For the Jan. – Jun. 2015 actual period return of 1.85% is based on May 2014 ROR Surveillance Report and for the Jul. – Dec. 2015 estimated period return of 1.89% is based on May 2015 ROR Surveillance Report per FPSC Order No. PSC-12-0425-PAA-EU.

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

FORM: 42-8E

JANUARY 2015 THROUGH DECEMBER 2015

| | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | 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 | ($259,671) | ($240,303) | ($219,429) | ($199,349) | ($179,228) | ($159,381) | ($139,237) | ($119,092) | ($98,947) | ($78,802) | ($58,657) | ($38,513) | ($18,368) | |
| 2. Total Working Capital | ($259,671) | ($240,303) | ($219,429) | ($199,349) | ($179,228) | ($159,381) | ($139,237) | ($119,092) | ($98,947) | ($78,802) | ($58,657) | ($38,513) | ($18,368) | |
| 3. Average Net Working Capital Balance | | ($249,987) | ($229,866) | ($209,389) | ($189,288) | ($169,305) | ($149,309) | ($129,164) | ($109,019) | ($88,875) | ($68,730) | ($48,585) | ($28,440) | |
| 4. Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [a] | | ($1,660) | ($1,526) | ($1,390) | ($1,257) | ($1,124) | ($991) | ($845) | ($713) | ($581) | ($449) | ($318) | ($186) | |
| b. Debt Component [b] | | ($307) | ($283) | ($257) | ($233) | ($208) | ($184) | ($160) | ($135) | ($110) | ($85) | ($60) | ($35) | |
| 5. Total Return Component [e] | | ($1,967) | ($1,809) | ($1,648) | ($1,489) | ($1,332) | ($1,175) | ($1,005) | ($848) | ($692) | ($535) | ($378) | ($221) | ($13,099) |
| 6. Expense Dr(Cr) | | | | | | | | | | | | | | |
| a. 411.800 Gains from Dispositions of Allowances | | ($19,368) | ($20,874) | ($20,031) | ($20,121) | ($20,121) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | |
| b. 411.900 Losses from Dispositions of Allowances | | $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 | |
| 7. Net Expense (Lines 6a + 6b + 6c) [f] | | ($19,368) | ($20,874) | ($20,031) | ($20,121) | ($20,121) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | ($20,145) | ($241,529) |
| 8. Total System Recoverable Expenses (Lines 5 + 7) | | ($21,335) | ($22,683) | ($21,679) | ($21,610) | ($21,453) | ($21,320) | ($21,150) | ($20,993) | ($20,836) | ($20,680) | ($20,523) | ($20,366) | |
| a. Recoverable Costs Allocated to Energy | | ($21,335) | ($22,683) | ($21,679) | ($21,610) | ($21,453) | ($21,320) | ($21,150) | ($20,993) | ($20,836) | ($20,680) | ($20,523) | ($20,366) | |
| b. Recoverable Costs Allocated to Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 9. Energy Jurisdictional Factor | | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | 95.26108% | |
| 10. Demand Jurisdictional Factor | | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | 94.64598% | |
| 11. Retail Energy-Related Recoverable Costs [c] | | ($20,324) | ($21,608) | ($20,652) | ($20,586) | ($20,437) | ($20,309) | ($20,148) | ($19,998) | ($19,849) | ($19,700) | ($19,550) | ($19,401) | |
| 12. Retail Demand-Related Recoverable Costs [d] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 13. Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | ($20,324) | ($21,608) | ($20,652) | ($20,586) | ($20,437) | ($20,309) | ($20,148) | ($19,998) | ($19,849) | ($19,700) | ($19,550) | ($19,401) | ($242,561) |

[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. 2015 actual period is 4.8938% based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per May 2015 ROR Surveillance Report,FPSC Order No. PSC-12-0425-PAA-EU.

[b] The Debt Component for the Jan. – Jun. 2015 actual period is 1.4751% based on May 2014 ROR Surveillance Report and the Debt Component for the Jul. – Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

[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**
**2015 Annual Capital Depreciation Schedule**

| Project Name | Function | Site/Unit | Account | Depreciation Rate / Amortization Period | Actual Balance Dec 2014 | Estimated Balance Dec 2015 |
|---|---|---|---|---|---|---|
| **002-LOW NOX BURNER TECHNOLOGY** | 02 - Steam Generation Plant | Turkey Pt U1 | 31200 | 2.50% | 2,563,376 | 2,563,376 |
| **002-LOW NOX BURNER TECHNOLOGY Total** | | | | | **2,563,376** | **2,563,376** |
| **003-CONTINUOUS EMISSION MONITORING** | 02 - Steam Generation Plant | Manatee Comm | 31200 | 2.60% | 65,605 | 65,605 |
| | 02 - Steam Generation Plant | Manatee U1 | 31100 | 2.10% | 56,430 | 56,430 |
| | 02 - Steam Generation Plant | Manatee U1 | 31200 | 2.60% | 558,926 | 640,630 |
| | 02 - Steam Generation Plant | Manatee U2 | 31100 | 2.10% | 56,333 | 56,333 |
| | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 599,476 | 740,318 |
| | 02 - Steam Generation Plant | Martin Comm | 31200 | 2.60% | 31,632 | 31,632 |
| | 02 - Steam Generation Plant | Martin Comm | 31650 | 20.00% | 123,576 | 58,207 |
| | 02 - Steam Generation Plant | Martin Comm | 31670 | 14.29% | - | 66,897 |
| | 02 - Steam Generation Plant | Martin U1 | 31100 | 2.10% | 36,811 | 36,811 |
| | 02 - Steam Generation Plant | Martin U1 | 31200 | 2.60% | 533,645 | 533,645 |
| | 02 - Steam Generation Plant | Martin U2 | 31100 | 2.10% | 36,845 | 36,845 |
| | 02 - Steam Generation Plant | Martin U2 | 31200 | 2.60% | 529,520 | 529,520 |
| | 02 - Steam Generation Plant | Scherer U4 | 31200 | 2.60% | 515,653 | 515,653 |
| | 02 - Steam Generation Plant | SJRPP - Comm | 31100 | 2.10% | 43,193 | 43,193 |
| | 02 - Steam Generation Plant | SJRPP U1 | 31200 | 2.60% | 780 | 780 |
| | 02 - Steam Generation Plant | SJRPP U2 | 31200 | 2.60% | 780 | 780 |
| | 02 - Steam Generation Plant | Turkey Pt Comm | 31100 | 2.10% | 59,056 | 59,056 |
| | 02 - Steam Generation Plant | Turkey Pt Comm | 31200 | 2.50% | 29,142 | 29,142 |
| | 02 - Steam Generation Plant | Turkey Pt U1 | 31200 | 2.50% | 382,004 | 382,004 |
| | 05 - Other Generation Plant | FtLauderdale Comm | 34100 | 3.50% | 58,860 | 58,860 |
| | 05 - Other Generation Plant | FtLauderdale Comm | 34500 | 3.40% | 34,502 | 34,502 |
| | 05 - Other Generation Plant | FtLauderdale GTs | 34300 | 2.90% | 10,225 | 10,225 |
| | 05 - Other Generation Plant | FtLauderdale U4 | 34300 | 4.30% | 487,395 | 487,395 |
| | 05 - Other Generation Plant | FtLauderdale U5 | 34300 | 4.20% | 498,340 | 498,340 |
| | 05 - Other Generation Plant | FtMyers U2 | 34300 | 4.20% | 165,032 | 165,032 |
| | 05 - Other Generation Plant | FtMyers U3 | 34300 | 5.20% | 2,283 | 2,283 |
| | 05 - Other Generation Plant | Manatee U3 | 34300 | 4.30% | 87,691 | 87,691 |
| | 05 - Other Generation Plant | Martin U3 | 34300 | 4.20% | 421,385 | 421,385 |
| | 05 - Other Generation Plant | Martin U4 | 34300 | 4.20% | 413,986 | 413,986 |
| | 05 - Other Generation Plant | Martin U8 | 34300 | 4.30% | 13,693 | 13,693 |
| | 05 - Other Generation Plant | Sanford U4 | 34300 | 4.80% | 171,843 | 171,843 |
| | 05 - Other Generation Plant | Sanford U5 | 34300 | 4.20% | 134,809 | 134,809 |
| **003-CONTINUOUS EMISSION MONITORING Total** | | | | | **6,159,452** | **6,383,526** |
| **004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION** | 02 - Steam Generation Plant | Turkey Pt Comm | 31100 | 2.10% | 21,799 | 21,799 |
| **004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION Total** | | | | | **21,799** | **21,799** |
| **005-MAINTENANCE OF ABOVE GROUND FUEL TANKS** | 02 - Steam Generation Plant | Manatee Comm | 31100 | 2.10% | 3,111,263 | 3,111,263 |
| | 02 - Steam Generation Plant | Manatee Comm | 31200 | 2.60% | 174,543 | 174,543 |
| | 02 - Steam Generation Plant | Manatee U1 | 31200 | 2.60% | 104,845 | 104,845 |
| | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 127,429 | 127,429 |
| | 02 - Steam Generation Plant | Martin Comm | 31100 | 2.10% | 1,110,450 | 1,110,450 |
| | 02 - Steam Generation Plant | Martin Comm | 31200 | 2.60% | 94,329 | 94,329 |
| | 02 - Steam Generation Plant | Martin U1 | 31100 | 2.10% | 261,417 | 261,417 |
| | 02 - Steam Generation Plant | Martin U2 | 31100 | 2.10% | 85,078 | 85,078 |
| | 02 - Steam Generation Plant | SJRPP - Comm | 31100 | 2.10% | 42,091 | 42,091 |
| | 02 - Steam Generation Plant | SJRPP - Comm | 31200 | 2.60% | 2,292 | 2,292 |
| | 02 - Steam Generation Plant | Turkey Pt Comm | 31100 | 2.10% | 87,560 | 87,560 |
| | 05 - Other Generation Plant | FtLauderdale Comm | 34200 | 3.80% | 898,111 | 898,111 |
| | 05 - Other Generation Plant | FtLauderdale GTs | 34200 | 2.60% | 584,290 | 584,290 |
| | 05 - Other Generation Plant | FtMyers GTs | 34200 | 2.70% | 133,479 | 133,479 |
| | 05 - Other Generation Plant | FtMyers U3 | 34200 | 3.80% | 18,616 | 18,616 |
| | 05 - Other Generation Plant | Martin Comm | 34200 | 3.80% | 450,656 | 455,336 |
| | 05 - Other Generation Plant | PtEverglades GTs | 34200 | 2.60% | 2,768,744 | 2,768,744 |
| | 08 - General Plant | General Plant | 39000 | 2.10% | - | 5,837,840 |
| **005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total** | | | | | **10,055,195** | **15,897,715** |
| **007-RELOCATE TURBINE LUBE OIL PIPING** | 03 - Nuclear Generation Plant | StLucie U1 | 32300 | 2.40% | 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 | 2.10% | 46,882 | 46,882 |
| | 02 - Steam Generation Plant | Manatee Comm | 31670 | 14.29% | 92,617 | 54,241 |
| | 02 - Steam Generation Plant | Martin Comm | 31600 | 2.40% | 23,107 | 23,107 |
| | 02 - Steam Generation Plant | Martin Comm | 31650 | 20.00% | 3,883 | 56,000 |
| | 02 - Steam Generation Plant | Martin Comm | 31670 | 14.29% | 202,707 | 263,330 |
| | 02 - Steam Generation Plant | Turkey Pt Comm | 31100 | 2.10% | 5,895 | 5,895 |
| | 02 - Steam Generation Plant | Turkey Pt Comm | 31670 | 14.29% | 2,576 | 2,576 |
| | 05 - Other Generation Plant | FtLauderdale Comm | 34100 | 3.50% | 363,996 | 363,996 |
| | 05 - Other Generation Plant | FtMyers Comm | 34650 | 20.00% | 9,728 | 9,728 |
| | 05 - Other Generation Plant | Sanford Comm | 34100 | 3.50% | 16,035 | 15,922 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36670 | 2.00% | 2,995 | 2,995 |
| | 08 - General Plant | General Plant | 39000 | 2.10% | 4,413 | 4,413 |
| | 08 - General Plant | General Plant | 39190 | 33.33% | 6,261 | 8,552 |
| **008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total** | | | | | **781,095** | **857,637** |

| Project Name | Function | Site/Unit | Account | Depreciation Rate / Amortization Period | Actual Balance Dec 2014 | Estimated Balance Dec 2015 |
|---|---|---|---|---|---|---|
| **010-REROUTE STORMWATER RUNOFF** | 03 - Nuclear Generation Plant | StLucie Comm | 32100 | 1.80% | 117,794 | 117,794 |
| **010-REROUTE STORMWATER RUNOFF Total** | | | | | **117,794** | **117,794** |
| 012-SCHERER DISCHARGE PIPELINE | 02 - Steam Generation Plant | Scherer Comm | 31100 | 2.10% | 524,873 | 524,873 |
| 012-SCHERER DISCHARGE PIPELINE | 02 - Steam Generation Plant | Scherer Comm | 31200 | 2.60% | 328,762 | 328,762 |
| 012-SCHERER DISCHARGE PIPELINE | 02 - Steam Generation Plant | Scherer Comm | 31400 | 2.59% | 689 | 689 |
| **012-SCHERER DISCHARGE PIPELINE Total** | | | | | **854,324** | **854,324** |
| **020-WASTEWATER/STORMWATER DISCH ELIMINATION** | 02 - Steam Generation Plant | Martin U1 | 32100 | 2.60% | 367,906 | 367,906 |
| | 02 - Steam Generation Plant | Martin U2 | | 2.60% | 403,671 | 403,671 |
| **020-WASTEWATER/STORMWATER DISCH ELIMINATION Total** | | | 31200 | | **771,577** | **771,577** |
| **021-ST.LUCIE TURTLE NETS** | 03 - Nuclear Generation Plant | StLucie Comm | 31200 | 1.80% | 352,942 | 6,078,732 |
| **021-ST.LUCIE TURTLE NETS Total** | | | | | **352,942** | **6,078,732** |
| **022-PIPELINE INTEGRITY MANAGEMENT** | 02 - Steam Generation Plant | Manatee Comm | 31100 | 2.10% | 620,473 | 601,217 |
| | 02 - Steam Generation Plant | Martin Comm | 31100 | 2.10% | 2,271,574 | 2,271,574 |
| **022-PIPELINE INTEGRITY MANAGEMENT Total** | | | | | **2,892,047** | **2,872,791** |
| **023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES** | 02 - Steam Generation Plant | Manatee Comm | 31100 | 2.10% | 816,259 | 816,259 |
| | 02 - Steam Generation Plant | Manatee Comm | 31200 | 2.60% | 33,272 | 33,272 |
| | 02 - Steam Generation Plant | Manatee Comm | 31500 | 2.40% | 26,325 | 26,325 |
| | 02 - Steam Generation Plant | Manatee U1 | 31200 | 2.60% | 45,750 | 45,750 |
| | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 37,431 | 37,431 |
| | 02 - Steam Generation Plant | Martin Comm | 31100 | 2.10% | 343,785 | 343,785 |
| | 02 - Steam Generation Plant | Martin Comm | 31500 | 2.40% | 34,755 | 34,755 |
| | 02 - Steam Generation Plant | Turkey Pt Comm | 31100 | 2.10% | 92,013 | 92,013 |
| | 03 - Nuclear Generation Plant | StLucie U1 | 32300 | 2.40% | 712,225 | 712,225 |
| | 03 - Nuclear Generation Plant | StLucie U1 | 32400 | 1.80% | 745,335 | 745,335 |
| | 03 - Nuclear Generation Plant | StLucie U2 | 32300 | 2.40% | 552,390 | 552,390 |
| | 05 - Other Generation Plant | FtLauderdale Comm | 34100 | 3.50% | 189,219 | 189,219 |
| | 05 - Other Generation Plant | FtLauderdale Comm | 34200 | 3.80% | 1,480,169 | 1,480,169 |
| | 05 - Other Generation Plant | FtLauderdale Comm | 34300 | 6.00% | 28,250 | 28,250 |
| | 05 - Other Generation Plant | FtLauderdale GTs | 34100 | 2.20% | 92,727 | 92,727 |
| | 05 - Other Generation Plant | FtLauderdale GTs | 34200 | 2.60% | 513,250 | 513,250 |
| | 05 - Other Generation Plant | FtMyers GTs | 34100 | 2.30% | 98,715 | 98,715 |
| | 05 - Other Generation Plant | FtMyers GTs | 34200 | 2.70% | 629,983 | 629,983 |
| | 05 - Other Generation Plant | FtMyers GTs | 34500 | 2.20% | 12,430 | 12,430 |
| | 05 - Other Generation Plant | FtMyers U2 | 34300 | 4.20% | 49,727 | 49,727 |
| | 05 - Other Generation Plant | FtMyers U3 | 34500 | 3.40% | 12,430 | 12,430 |
| | 05 - Other Generation Plant | Martin Comm | 34100 | 3.50% | 523,498 | 523,498 |
| | 05 - Other Generation Plant | Martin U8 | 34200 | 3.80% | 84,868 | 84,868 |
| | 05 - Other Generation Plant | PtEverglades Comm | 34200 | 3.30% | - | 1,607,728 |
| | 05 - Other Generation Plant | PtEverglades GTs | 34100 | 2.20% | 454,081 | 454,081 |
| | 05 - Other Generation Plant | PtEverglades GTs | 34200 | 2.60% | 1,835,190 | 1,835,190 |
| | 05 - Other Generation Plant | PtEverglades GTs | 34500 | 2.10% | 7,783 | 7,783 |
| | 05 - Other Generation Plant | Sanford Comm | 34100 | 3.50% | 288,383 | 288,383 |
| | 06 - Transmission Plant - Electric | Mass Distribution Plant | 36100 | 1.90% | - | - |
| | 06 - Transmission Plant - Electric | Radial | 35200 | 1.90% | 6,946 | 6,946 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35200 | 1.90% | 1,092,385 | 1,164,630 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35300 | 2.60% | 177,982 | 177,982 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35800 | 1.80% | 65,655 | 65,655 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36100 | 1.90% | 3,117,540 | 3,143,351 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36670 | 2.00% | 70,499 | 70,499 |
| | 08 - General Plant | General Plant | 39000 | 2.10% | 146,691 | 146,691 |
| **023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES Total** | | | | | **14,417,942** | **16,123,727** |
| **024-GAS REBURN** | 02 - Steam Generation Plant | Manatee U1 | 31200 | 2.60% | 16,687,067 | 16,687,312 |
| | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 15,277,112 | 15,506,591 |
| **024-GAS REBURN Total** | | | | | **31,964,179** | **32,193,902** |
| **026-UST REPLACEMENT/REMOVAL** | 08 - General Plant | General Plant | 39000 | 2.10% | 115,447 | 115,447 |
| **026-UST REPLACEMENT/REMOVAL Total** | | | | | **115,447** | **115,447** |
| **031-CLEAN AIR INTERSTATE RULE-CAIR** | 02 - Steam Generation Plant | Manatee Comm | 31100 | 2.10% | 102,052 | 102,052 |
| | 02 - Steam Generation Plant | Manatee U1 | 31200 | 2.60% | 20,059,060 | 20,059,060 |
| | 02 - Steam Generation Plant | Manatee U1 | 31400 | 2.60% | 7,240,711 | 7,240,711 |
| | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 20,461,529 | 20,461,529 |
| | 02 - Steam Generation Plant | Manatee U2 | 31400 | 2.60% | 7,905,907 | 7,905,907 |
| | 02 - Steam Generation Plant | Martin Comm | 31200 | 2.60% | 518,275 | 518,275 |
| | 02 - Steam Generation Plant | Martin Comm | 31400 | 2.60% | 287,258 | 287,258 |
| | 02 - Steam Generation Plant | Martin U1 | 31200 | 2.60% | 19,504,077 | 19,504,077 |
| | 02 - Steam Generation Plant | Martin U1 | 31400 | 2.60% | 7,499,710 | 7,499,710 |
| | 02 - Steam Generation Plant | Martin U2 | 31200 | 2.60% | 20,248,975 | 20,248,975 |
| | 02 - Steam Generation Plant | Martin U2 | 31400 | 2.60% | 7,477,120 | 7,477,120 |
| | 02 - Steam Generation Plant | Scherer U4 | 31100 | 2.10% | 83,049,769 | 82,935,636 |
| | 02 - Steam Generation Plant | Scherer U4 | 31200 | 2.60% | 252,034,914 | 253,051,547 |
| | 02 - Steam Generation Plant | Scherer U4 | 31400 | 2.60% | 507,244 | 477,256 |
| | 02 - Steam Generation Plant | Scherer U4 | 31500 | 2.40% | 19,237,659 | 19,219,358 |
| | 02 - Steam Generation Plant | Scherer U4 | 31600 | 2.40% | 2,206,227 | 2,190,752 |
| | 02 - Steam Generation Plant | Scherer U4 | 31670 | 14.29% | 12,507 | 12,507 |
| | 02 - Steam Generation Plant | SJRPP U1 | 31200 | 2.60% | 27,740,234 | 27,750,108 |
| | 02 - Steam Generation Plant | SJRPP U1 | 31500 | 2.40% | 451,890 | 446,734 |
| | 02 - Steam Generation Plant | SJRPP U1 | 31600 | 2.40% | 9,138 | 9,138 |
| | 02 - Steam Generation Plant | SJRPP U2 | 31200 | 2.60% | 26,534,954 | 26,540,984 |
| | 02 - Steam Generation Plant | SJRPP U2 | 31500 | 2.40% | 426,220 | 426,220 |
| | 02 - Steam Generation Plant | SJRPP U2 | 31600 | 2.40% | 9,591 | 9,591 |
| | 05 - Other Generation Plant | FtLauderdale GTs | 34300 | 2.90% | 110,242 | 110,242 |
| | 05 - Other Generation Plant | FtMyers GTs | 34300 | 3.10% | 57,855 | 57,855 |
| | 05 - Other Generation Plant | Martin Comm | 34100 | 3.50% | 763,350 | 763,350 |
| | 05 - Other Generation Plant | Martin Comm | 34300 | 4.30% | 244,343 | 244,343 |
| | 05 - Other Generation Plant | Martin Comm | 34500 | 3.40% | 292,499 | 292,499 |
| | 05 - Other Generation Plant | PtEverglades GTs | 34300 | 3.40% | 107,874 | 107,874 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36500 | 3.90% | 411,775 | 411,775 |
| **031-CLEAN AIR INTERSTATE RULE-CAIR Total** | | | | | **525,512,958** | **526,362,444** |

| Project Name | Function | Site/Unit | Account | Depreciation Rate / Amortization Period | Actual Balance Dec 2014 | Estimated Balance Dec 2015 |
|---|---|---|---|---|---|---|
| 033-MATS Rule | 02 - Steam Generation Plant | Scherer U4 | 31100 | 2.10% | 225,600 | 225,068 |
| | 02 - Steam Generation Plant | Scherer U4 | 31200 | 2.60% | 106,958,839 | 106,958,839 |
| | 02 - Steam Generation Plant | SJRPP U1 | 31200 | 2.60% | - | 36,805 |
| 033-MATS Rule Total | | | | | 107,184,439 | 107,220,712 |
| 034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE | 03 - Nuclear Generation Plant | StLucie Comm | 32100 | 1.80% | - | - |
| 034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE Total | | | | | - | - |
| 035-MARTIN PLANT DRINKING WATER COMP | 02 - Steam Generation Plant | Martin Comm | 31100 | 2.10% | 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 | 1.80% | 7,601,405 | 7,601,405 |
| | 03 - Nuclear Generation Plant | Turkey Pt Comm | 32100 | 1.80% | - | 9,806,188 |
| 036-LOW LEV RADI WSTE-LLW Total | | | | | 7,601,405 | 17,407,593 |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto Solar | 34000 | 0.00% | 255,507 | 255,507 |
| | 05 - Other Generation Plant | Desoto Solar | 34100 | 3.30% | 4,502,770 | 4,502,770 |
| | 05 - Other Generation Plant | Desoto Solar | 34300 | 3.30% | 115,297,908 | 115,297,908 |
| | 05 - Other Generation Plant | Desoto Solar | 34500 | 3.30% | 26,746,266 | 26,746,266 |
| | 05 - Other Generation Plant | Desoto Solar | 34600 | 3.30% | - | 649,885 |
| | 05 - Other Generation Plant | Desoto Solar | 34630 | 33.33% | 20,537 | 20,537 |
| | 05 - Other Generation Plant | Desoto Solar | 34650 | 20.00% | 21,935 | 25,133 |
| | 05 - Other Generation Plant | Desoto Solar | 34670 | 14.29% | 97,753 | 101,556 |
| | 06 - Transmission Plant - Electric | TransGeneratorLead | 35300 | 2.60% | 311,577 | 313,491 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35200 | 1.90% | 7,427 | 7,427 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35300 | 2.60% | 920,949 | 920,949 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35310 | 2.90% | 1,698,382 | 1,697,968 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35500 | 3.40% | 394,418 | 394,418 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35600 | 3.20% | 191,358 | 191,358 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36100 | 1.90% | 540,994 | 540,994 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36200 | 2.60% | 1,938,179 | 1,938,179 |
| | 08 - General Plant | General Plant | 39220 | 9.40% | 28,426 | 28,426 |
| | 08 - General Plant | General Plant | 39720 | 14.29% | 21,238 | 21,238 |
| 037-DE SOTO SOLAR PROJECT Total | | | | | 152,995,624 | 153,654,009 |
| 038-SPACE COAST SOLAR PROJECT | 01 - Intangible Plant | Intangible Plant | 30300 | 0.00% | 6,359,027 | 6,359,027 |
| | 05 - Other Generation Plant | Space Coast Solar | 34100 | 3.30% | 3,838,726 | 3,838,726 |
| | 05 - Other Generation Plant | Space Coast Solar | 34300 | 3.30% | 51,606,083 | 51,606,083 |
| | 05 - Other Generation Plant | Space Coast Solar | 34500 | 3.30% | 6,126,699 | 6,126,699 |
| | 05 - Other Generation Plant | Space Coast Solar | 34600 | 3.30% | - | 16,683 |
| | 05 - Other Generation Plant | Space Coast Solar | 34630 | 33.33% | 1,310 | 1,310 |
| | 05 - Other Generation Plant | Space Coast Solar | 34650 | 20.00% | 9,438 | 23,642 |
| | 05 - Other Generation Plant | Space Coast Solar | 34670 | 14.29% | 51,560 | 51,560 |
| | 06 - Transmission Plant - Electric | TransGeneratorLead | 35300 | 2.60% | 789,138 | 789,138 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35300 | 2.60% | 139,391 | 139,391 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35310 | 2.90% | 1,328,699 | 1,328,699 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36100 | 1.90% | 274,858 | 274,858 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36200 | 2.60% | 62,689 | 62,689 |
| | 08 - General Plant | General Plant | 39220 | 9.40% | 31,858 | 31,858 |
| | 08 - General Plant | General Plant | 39720 | 14.29% | 6,741 | 6,741 |
| 038-SPACE COAST SOLAR PROJECT Total | | | | | 70,626,217 | 70,657,104 |
| 039-MARTIN SOLAR PROJECT | 05 - Other Generation Plant | Martin U8 | 34300 | 4.30% | 423,126 | 423,126 |
| | 05 - Other Generation Plant | Martin Solar | 34000 | 0.00% | 216,844 | 216,844 |
| | 05 - Other Generation Plant | Martin Solar | 34100 | 3.30% | 20,746,646 | 20,746,646 |
| | 05 - Other Generation Plant | Martin Solar | 34300 | 3.30% | 398,450,800 | 395,164,560 |
| | 05 - Other Generation Plant | Martin Solar | 34500 | 3.30% | 4,125,204 | 4,125,204 |
| | 05 - Other Generation Plant | Martin Solar | 34600 | 3.30% | 1,299 | 1,299 |
| | 05 - Other Generation Plant | Martin Solar | 34650 | 20.00% | 32,562 | 11,178 |
| | 05 - Other Generation Plant | Martin Solar | 34670 | 14.29% | 11,896 | 11,896 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35500 | 3.40% | 603,692 | 603,692 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35600 | 3.20% | 364,159 | 364,159 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36400 | 4.10% | 9,282 | 9,282 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36660 | 1.50% | 94,476 | 94,476 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36760 | 2.60% | 2,728 | 2,728 |
| | 08 - General Plant | General Plant | 39220 | 9.40% | 25,193 | 25,193 |
| | 08 - General Plant | General Plant | 39240 | 11.10% | 399,176 | 399,176 |
| | 08 - General Plant | General Plant | 39290 | 3.50% | 114,262 | 114,262 |
| | 08 - General Plant | General Plant | 39420 | 14.29% | 18,993 | 18,993 |
| | 08 - General Plant | General Plant | 39720 | 14.29% | 3,204 | 3,204 |
| 039-MARTIN SOLAR PROJECT Total | | | | | 425,643,543 | 422,335,919 |
| 041-PRV MANATEE HEATING SYSTEM | 02 - Steam Generation Plant | PtEverglades Comm | 31400 | CRS | 1,478,577 | 1,478,577 |
| | 05 - Other Generation Plant | CapeCanaveral Comm | 34300 | CRS | 4,042,459 | 4,042,459 |
| | 06 - Transmission Plant - Electric | Transmission Plant - Electric | 35300 | 2.60% | 276,404 | 276,404 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36100 | 1.90% | 73,267 | 73,267 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36200 | 2.60% | 472,661 | 472,661 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36400 | 4.10% | 225,952 | 225,952 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36500 | 3.90% | 307,599 | 307,599 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36660 | 1.50% | 221,326 | 221,326 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36760 | 2.60% | 168,995 | 168,995 |
| | 07 - Distribution Plant - Electric | Mass Distribution Plant | 36910 | CRS | 607 | 607 |
| | 08 - General Plant | General Plant | 39720 | 14.29% | 16,244 | 16,244 |
| 041-PRV MANATEE HEATING SYSTEM Total | | | | | 7,284,092 | 7,284,092 |
| 042-PTN COOLING CANAL MONITORING SYS | 03 - Nuclear Generation Plant | Turkey Pt Comm | 32100 | 1.80% | 3,582,753 | 8,941,833 |
| 042-PTN COOLING CANAL MONITORING SYS Total | | | | | 3,582,753 | 8,941,833 |
| 044-Barley Barber Swamp Iron Mitiga | 02 - Steam Generation Plant | Martin Comm | 31100 | 2.10% | 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 | 2.60% | - | - |
| | 02 - Steam Generation Plant | Manatee U1 | 31200 | 2.60% | 44,965,950 | 44,988,527 |
| | 02 - Steam Generation Plant | Manatee U1 | 31500 | 2.40% | 4,409,109 | 4,409,692 |
| | 02 - Steam Generation Plant | Manatee U1 | 31600 | 2.40% | 1,021,783 | 1,021,918 |
| | 02 - Steam Generation Plant | Manatee U2 | 31200 | 2.60% | 51,910,750 | 51,927,967 |
| | 02 - Steam Generation Plant | Manatee U2 | 31500 | 2.40% | 4,661,952 | 4,661,952 |
| | 02 - Steam Generation Plant | Manatee U2 | 31600 | 2.40% | 1,051,553 | 1,051,553 |
| | 02 - Steam Generation Plant | Martin U1 | 31200 | 2.60% | 46,720,527 | 47,146,158 |
| | 02 - Steam Generation Plant | Martin U1 | 31500 | 2.40% | 4,288,249 | 4,322,420 |
| | 02 - Steam Generation Plant | Martin U1 | 31600 | 2.40% | 993,796 | 1,002,877 |
| | 02 - Steam Generation Plant | Martin U2 | 31200 | 2.60% | 49,280,072 | 53,920,018 |
| 045-800 MW UNIT ESP PROJECT Total | | | | | 209,303,741 | 214,453,082 |
| Grand Total | | | | | 1,581,233,081 | 1,613,600,273 |

**FLORIDA POWER & LIGHT COMPANY**
**COST RECOVERY CLAUSES**

**CAPITAL STRUCTURE AND COST RATES PER**
**MAY 2014 EARNINGS SURVEILLANCE REPORT**

**Equity @ 10.50%**

| | ADJUSTED RETAIL | RATIO | MIDPOINT COST RATES | WEIGHTED COST | PRE-TAX WEIGHTED COST |
|---|---|---|---|---|---|
| LONG_TERM_DEBT | 7,260,190,891 | 29.609% | 4.77% | 1.41% | 1.41% |
| SHORT_TERM_DEBT | 303,811,216 | 1.239% | 2.18% | 0.03% | 0.03% |
| PREFERRED_STOCK | 0 | 0.000% | 0.00% | 0.00% | 0.00% |
| CUSTOMER_DEPOSITS | 422,415,505 | 1.723% | 2.04% | 0.04% | 0.04% |
| COMMON_EQUITY | 11,427,411,916 | 46.604% | 10.50% | 4.89% | 7.97% |
| DEFERRED_INCOME_TAX | 5,104,824,995 | 20.819% | 0.00% | 0.00% | 0.00% |
| INVESTMENT_TAX_CREDITS | | | | | |
| ZERO COST | 0 | 0.000% | 0.00% | 0.00% | 0.00% |
| WEIGHTED COST | 1,326,963 | 0.005% | 8.27% | 0.00% | 0.00% |
| TOTAL | $24,519,981,486 | 100.00% | | 6.37% | 9.44% |

**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 | $7,260,190,891 | 38.85% | 4.772% | 1.854% | 1.854% |
| PREFERRED STOCK | 0 | 0.00% | 0.000% | 0.000% | 0.000% |
| COMMON EQUITY | 11,427,411,916 | 61.15% | 10.500% | 6.421% | 10.453% |
| TOTAL | $18,687,602,807 | 100.00% | | 8.275% | 12.307% |
| RATIO | | | | | |

| | |
|---|---|
| DEBT COMPONENTS: | |
| LONG TERM DEBT | 1.4129% |
| SHORT TERM DEBT | 0.0270% |
| CUSTOMER DEPOSITS | 0.0352% |
| TAX CREDITS -WEIGHTED | 0.0001% |
| TOTAL DEBT | **1.4751%** |
| EQUITY COMPONENTS: | |
| PREFERRED STOCK | 0.0000% |
| COMMON EQUITY | 4.8935% |
| TAX CREDITS -WEIGHTED | 0.0003% |
| TOTAL EQUITY | **4.8938%** |
| TOTAL | 6.3690% |
| PRE-TAX EQUITY | 7.9671% |
| PRE-TAX TOTAL | 9.4423% |

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

**FLORIDA POWER & LIGHT COMPANY**
**COST RECOVERY CLAUSES**

**Equity @ 10.50%**

**CAPITAL STRUCTURE AND COST RATES PER MAY 2015 EARNINGS SURVEILLANCE REPORT**

| | ADJUSTED RETAIL | RATIO | MIDPOINT COST RATES | WEIGHTED COST | PRE-TAX WEIGHTED COST |
|---|---|---|---|---|---|
| LONG_TERM_DEBT | 7,868,539,536 | 29.834% | 4.80% | 1.43% | 1.43% |
| SHORT_TERM_DEBT | 346,840,443 | 1.315% | 2.03% | 0.03% | 0.03% |
| PREFERRED_STOCK | 0 | 0.000% | 0.00% | 0.00% | 0.00% |
| CUSTOMER_DEPOSITS | 421,524,845 | 1.598% | 2.04% | 0.03% | 0.03% |
| COMMON_EQUITY | 12,106,290,409 | 45.901% | 10.50% | 4.82% | 7.85% |
| DEFERRED_INCOME_TAX | 5,629,438,935 | 21.344% | 0.00% | 0.00% | 0.00% |
| INVESTMENT_TAX_CREDITS | | | | | |
| ZERO COST | 0 | 0.000% | 0.00% | 0.00% | 0.00% |
| WEIGHTED COST | 2,138,560 | 0.008% | 8.25% | 0.00% | 0.00% |
| TOTAL | $26,374,772,728 | 100.00% | | 6.31% | 9.34% |

**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 | $7,868,539,536 | 39.39% | 4.796% | 1.889% | 1.889% |
| PREFERRED STOCK | 0 | 0.00% | 0.000% | 0.000% | 0.000% |
| COMMON EQUITY | 12,106,290,409 | 60.61% | 10.500% | 6.364% | 10.360% |
| TOTAL | $19,974,829,945 | 100.00% | | 8.253% | 12.250% |
| RATIO | | | | | |

| | |
|---|---|
| DEBT COMPONENTS: | |
| LONG TERM DEBT | 1.4309% |
| SHORT TERM DEBT | 0.0267% |
| CUSTOMER DEPOSITS | 0.0326% |
| TAX CREDITS -WEIGHTED | 0.0002% |
| TOTAL DEBT | **1.4904%** |
| EQUITY COMPONENTS: | |
| PREFERRED STOCK | 0.0000% |
| COMMON EQUITY | 4.8196% |
| TAX CREDITS -WEIGHTED | 0.0005% |
| TOTAL EQUITY | **4.8201%** |
| TOTAL | 6.3105% |
| PRE-TAX EQUITY | 7.8472% |
| PRE-TAX TOTAL | 9.3375% |

**Note:**

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

# APPENDIX I

# ENVIRONMENTAL COST RECOVERY

## COMMISSION FORMS 42-1P THROUGH 42-8P
## JANUARY 2016 – DECEMBER 2016

**TJK-3**
**DOCKET NO. 150007-EI**
**FPL WITNESS: TERRY J. KEITH**
**EXHIBIT _____**
**PAGES 1-112**
**AUGUST 31, 2015**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 8
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Terry J. Keith TJK-3

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

FORM: 42-1P

JANUARY 2016 THROUGH DECEMBER 2016

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| | Energy | CP Demand | GCP Demand | Total |
| 1. Total Jurisdictional Revenue Requirements for the projected period | | | | |
| a. Projected O&M Activities [a] | $41,010,310 | $7,879,031 | $2,734,611 | $51,623,952 |
| b. Projected Capital Projects [b] | $29,846,543 | $148,109,898 | $0 | $177,956,440 |
| c. Total Jurisdictional Revenue Requirements [c] | $70,856,853 | $155,988,929 | $2,734,611 | $229,580,392 |
| 2. True-up for Estimated Over/(Under) Recovery [d] | ($12,452,812) | ($24,782,392) | ($384,508) | ($37,619,712) |
| 3. Final True-up Over/(Under) [e] | ($716,422) | ($2,423,620) | ($24,366) | ($3,164,408) |
| 4. Total Jurisdictional Amount to be Recovered/(Refunded) [f] | $84,026,087 | $183,194,941 | $3,143,485 | $270,364,512 |
| 5. Total Projected Jurisdictional Amount Adjusted for Taxes [g] | $84,086,585 | $183,326,841 | $3,145,748 | $270,559,175 |

[a] FORM 42-2P, Page 3, Lines 7 through 9

[b] FORM 42-3P, Page 5, Lines 7 through 9

[c] Lines 1a + 1b

[d] For the current period January 2015 - December 2015 (FORM 42-1E, Line 4, filed on July 31, 2015)

[e] For the period January 2014 - December 2014 (FORM 42-1A, Line 7, filed on April 1, 2015)

[f] (Line 1 - Line 2 - Line 3)

[g] Line 4 x Revenue Tax Multiplier 1.00072

Note: Allocation to energy and demand in each period are in proportion to the respective period split of costs.

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

Totals may not add due to rounding.

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

FORM: 42-2P

JANUARY 2016 THROUGH DECEMBER 2016

O&M ACTIVITIES

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PROJECT # | Monthly Data | | | | | | | | | | | | | Method of Classification | | |
| | 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 | Energy | CP Demand | GCP Demand |
| 1. Description of O&M Activities | | | | | | | | | | | | | | | | |
| 1 - Air Operating Permit Fees | $22,797 | $22,797 | $22,797 | $22,797 | $22,797 | $22,797 | $22,797 | $22,797 | $22,797 | $22,797 | $22,797 | $22,797 | $273,565 | $273,565 | | |
| 3a - Continuous Emission Monitoring Systems | $128,910 | $29,461 | $36,456 | $30,061 | $30,076 | $34,074 | $128,397 | $30,090 | $34,074 | $30,061 | $31,154 | $49,152 | $591,966 | $591,966 | | |
| 5a - Maintenance of Stationary Above Ground Fuel Storage Tanks | $60,000 | $5,000 | $53,045 | $34,505 | $25,608 | $13,455 | $5,835 | $16,135 | $0 | $0 | $0 | $0 | $213,583 | | $213,583 | |
| 8a - Oil Spill Clean-up/Response Equipment | $21,486 | $21,486 | $21,486 | $21,486 | $21,486 | $21,486 | $21,486 | $21,486 | $21,486 | $21,486 | $21,486 | $21,486 | $257,829 | $257,829 | | |
| 13 - RCRA (Resource Conservation & Recovery Act) Corrective Action | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | |
| 14 - NPDES Permit Fees | $69,200 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $69,200 | | $69,200 | |
| 17a - Disposal of Non-Containerized Liquid Waste | $0 | $0 | $0 | $2,500 | $0 | $0 | $0 | $2,500 | $0 | $0 | $0 | $0 | $5,000 | $5,000 | | |
| 19a - Substation Pollutant Discharge Prevention & Removal - Distribution | $294,497 | $294,497 | $294,497 | $294,497 | $194,497 | $174,497 | $174,497 | $174,497 | $174,497 | $209,497 | $219,497 | $235,144 | $2,734,611 | | | $2,734,611 |
| 19b - Substation Pollutant Discharge Prevention & Removal - Transmission | $177,682 | $127,682 | $77,682 | $77,682 | $77,682 | $52,682 | $52,682 | $52,682 | $52,682 | $92,682 | $86,594 | $77,691 | $1,006,105 | $77,393 | $928,712 | |
| NA - Amortization of Gains on Sales of Emissions Allowances | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($13,356) | ($13,356) | | |
| 21 - St. Lucie Turtle Nets | $0 | $0 | $0 | $0 | $0 | $0 | $30,000 | $16,000 | $16,000 | $16,000 | $16,000 | $16,000 | $110,000 | | $110,000 | |
| 22 - Pipeline Integrity Management | $0 | $30,000 | $30,000 | $30,000 | $36,000 | $58,000 | $5,000 | $7,500 | $0 | $0 | $0 | $0 | $196,500 | | $196,500 | |
| 23 - SPCC - Spill Prevention, Control & Countermeasures | $73,745 | $73,741 | $91,761 | $75,581 | $73,740 | $96,240 | $78,740 | $73,740 | $86,760 | $80,580 | $85,005 | $86,240 | $975,871 | | $975,871 | |
| 24 - Manatee Reburn | $0 | $0 | $95,898 | $95,898 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $191,795 | $191,795 | | |
| 27 - Lowest Quality Water Source | $12,000 | $12,000 | $12,000 | $12,000 | $12,000 | $12,000 | $12,000 | $12,000 | $12,000 | $12,000 | $12,000 | $12,000 | $144,000 | | $144,000 | |
| 28 - CWA 316(b) Phase II Rule | $31,105 | $50,023 | $30,676 | $30,003 | $56,834 | $37,551 | $37,215 | $37,888 | $37,551 | $37,215 | $64,046 | $70,673 | $520,780 | | $520,780 | |
| 29 - SCR Consumables | $35,794 | $35,794 | $54,695 | $53,294 | $36,495 | $36,495 | $35,794 | $37,195 | $37,856 | $37,155 | $37,856 | $37,856 | $476,279 | $476,279 | | |
| 30 - HBMP | $2,300 | $2,300 | $2,300 | $2,300 | $2,300 | $2,300 | $2,300 | $2,300 | $2,300 | $2,300 | $2,300 | $2,200 | $27,500 | | $27,500 | |
| 31 - Clean Air Interstate Rule (CAIR) Compliance | $591,811 | $611,811 | $593,218 | $591,811 | $612,514 | $592,514 | $591,811 | $613,218 | $592,514 | $591,811 | $592,514 | $592,514 | $7,168,062 | $7,168,062 | | |
| 33 - MATS Project | $251,506 | $251,506 | $251,506 | $251,506 | $251,506 | $251,506 | $251,506 | $251,506 | $251,506 | $251,506 | $251,506 | $251,506 | $3,018,075 | $3,018,075 | | |
| 35 - Martin Plant Drinking Water System Compliance | $2,983 | $2,983 | $2,983 | $2,983 | $2,983 | $2,983 | $2,983 | $2,983 | $2,983 | $2,983 | $2,983 | $2,983 | $35,800 | | $35,800 | |
| 37 - DeSoto Next Generation Solar Energy Center | $81,743 | $65,063 | $106,989 | $65,293 | $66,501 | $72,851 | $74,413 | $73,639 | $72,031 | $70,563 | $71,501 | $76,870 | $897,458 | | $897,458 | |
| 38 - Space Coast Next Generation Solar Energy Center | $24,657 | $19,557 | $35,217 | $19,772 | $21,872 | $24,002 | $27,657 | $23,787 | $24,872 | $19,687 | $19,372 | $28,444 | $288,893 | | $288,893 | |
| 39 - Martin Next Generation Solar Energy Center | $299,497 | $296,008 | $309,669 | $299,497 | $302,839 | $304,583 | $301,241 | $307,925 | $304,583 | $299,497 | $422,821 | $306,327 | $3,754,487 | | $3,754,487 | |
| 40 - Greenhouse Gas Reduction Program | $4,500 | $0 | $0 | $0 | $50,000 | $0 | $4,500 | $0 | $0 | $0 | $20,000 | $0 | $79,000 | $79,000 | | |
| 41 - Manatee Temporary Heating System | $33,566 | $26,417 | $31,705 | $95,352 | $222,799 | $265,585 | $257,542 | $208,884 | $268,368 | $218,077 | $179,939 | $78,584 | $1,886,820 | $1,886,820 | | |
| 42 - Turkey Point Cooling Canal Monitoring Plan | $163,300 | $199,967 | $4,613,300 | $4,583,301 | $4,583,300 | $4,274,967 | $4,358,667 | $4,358,667 | $208,667 | $208,667 | $208,667 | $240,330 | $28,001,800 | $28,001,800 | | |
| 45 - 800 MW Unit ESP | $92,911 | $92,911 | $98,819 | $92,911 | $95,865 | $95,865 | $92,911 | $98,819 | $145,405 | $92,911 | $95,865 | $110,665 | $1,205,861 | $1,205,861 | | |
| 46 - St. Lucie Cooling Water Discharge Monitoring | $0 | $0 | $25,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $25,000 | | $25,000 | |
| 47 - NPDES Permit Renewal Requirements | $2,135 | $4,939 | $10,600 | $0 | $11,500 | $0 | $2,135 | $4,489 | $10,600 | $0 | $11,500 | $0 | $57,898 | | $57,898 | |
| 48 - Industrial Boiler MACT | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $32,500 | $0 | $20,000 | $52,500 | | $52,500 | |
| 49 - Thermal Discharge Standards | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | |
| 50 - Steam Electric Effluent Guidelines Revised Rules | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | |
| 51 - Gopher Tortoise Relocations | $0 | $0 | $0 | $0 | $8,000 | $0 | $0 | $16,000 | $0 | $0 | $0 | $0 | $24,000 | | $24,000 | |
| 52 - Numeric Nutrient Criteria Water Quality Standards in Florida | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | |
| 2. Total of O&M Activities | $2,477,013 | $2,274,830 | $6,901,186 | $6,783,916 | $6,818,082 | $6,445,320 | $6,570,997 | $6,465,615 | $2,378,420 | $2,348,862 | $2,474,291 | $2,338,350 | $54,276,883 | $43,220,089 | $8,322,182 | $2,734,611 |

Note: Totals may not add due to rounding.

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

FORM: 42-2P

JANUARY 2016 THROUGH DECEMBER 2016

O&M ACTIVITIES

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 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 | $2,477,013 | $2,274,830 | $6,901,186 | $6,783,916 | $6,818,082 | $6,445,320 | $6,570,997 | $6,465,615 | $2,378,420 | $2,348,862 | $2,474,291 | $2,338,350 | $54,276,883 |
| 3. Recoverable Costs Allocated to Energy | $1,359,137 | $1,300,859 | $5,824,742 | $5,845,780 | $5,931,701 | $5,598,228 | $5,768,352 | $5,648,102 | $1,585,613 | $1,480,488 | $1,467,333 | $1,409,754 | $43,220,089 |
| 4a. Recoverable Costs Allocated to CP Demand | $823,378 | $679,474 | $781,947 | $643,640 | $691,884 | $672,595 | $628,148 | $643,016 | $618,310 | $658,877 | $787,462 | $693,452 | $8,322,182 |
| 4b. Recoverable Costs Allocated to GCP Demand | $294,497 | $294,497 | $294,497 | $294,497 | $194,497 | $174,497 | $174,497 | $174,497 | $174,497 | $209,497 | $219,497 | $235,144 | $2,734,611 |
| 5. Retail Energy Jurisdictional Factor | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | |
| 6a. Retail CP Demand Jurisdictional Factor | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | |
| 6b. Retail GCP 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 Energy Recoverable Costs | $1,289,647 | $1,234,348 | $5,526,932 | $5,546,894 | $5,628,422 | $5,311,999 | $5,473,425 | $5,359,323 | $1,504,543 | $1,404,793 | $1,392,310 | $1,337,675 | $41,010,310 |
| 8a. Jurisdictional CP Demand Recoverable Costs | $779,534 | $643,293 | $740,309 | $609,366 | $655,041 | $636,780 | $594,699 | $608,776 | $585,385 | $623,792 | $745,530 | $656,526 | $7,879,031 |
| 8b. Jurisdictional GCP Demand Recoverable Costs | $294,497 | $294,497 | $294,497 | $294,497 | $194,497 | $174,497 | $174,497 | $174,497 | $174,497 | $209,497 | $219,497 | $235,144 | $2,734,611 |
| 9. Total Jurisdictional Recoverable Costs for O&M Activities | $2,363,677 | $2,172,138 | $6,561,738 | $6,450,757 | $6,477,960 | $6,123,276 | $6,242,621 | $6,142,596 | $2,264,425 | $2,238,082 | $2,357,337 | $2,229,346 | $51,623,952 |

Note: Totals may not add due to rounding.

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

FORM: 42-3P

JANUARY 2016 THROUGH DECEMBER 2016

CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PROJECT # | Monthly Data | | | | | | | | | | | | | Method of Classification | |
| | 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 | Energy | Demand |
| 1. Description of Investment Projects | | | | | | | | | | | | | | | |
| 2 - Low NOX Burner Technology | $8,639 | $8,597 | $8,556 | $8,514 | $8,473 | $8,431 | $8,389 | $8,348 | $8,306 | $8,265 | $8,223 | $8,182 | $100,923 | $100,923 | |
| 3b - Continuous Emission Monitoring Systems | $42,249 | $42,105 | $41,960 | $42,415 | $42,869 | $42,722 | $42,576 | $42,429 | $42,282 | $42,136 | $41,989 | $41,843 | $507,575 | $507,575 | |
| 4b - Clean Closure Equivalency | $96 | $96 | $95 | $95 | $95 | $94 | $94 | $94 | $93 | $93 | $93 | $93 | $1,131 | $87 | $1,044 |
| 5b - Maintenance of Stationary Above Ground Fuel Storage Tanks | $130,235 | $129,990 | $129,746 | $129,501 | $129,256 | $129,012 | $128,767 | $128,522 | $128,278 | $128,033 | $127,789 | $127,544 | $1,546,673 | $118,975 | $1,427,698 |
| 7 - Relocate Turbine Lube Oil Underground Piping to Above Ground | $106 | $105 | $105 | $104 | $104 | $103 | $103 | $103 | $102 | $102 | $101 | $101 | $1,239 | $95 | $1,143 |
| 8b - Oil Spill Clean-up/Response Equipment | $12,032 | $11,982 | $11,932 | $11,882 | $11,832 | $11,782 | $11,733 | $12,488 | $13,242 | $13,189 | $13,106 | $13,738 | $148,938 | $11,457 | $137,481 |
| 10 - Relocate Storm Water Runoff | $612 | $611 | $610 | $608 | $607 | $606 | $604 | $603 | $601 | $600 | $599 | $597 | $7,258 | $558 | $6,700 |
| 12 - Scherer Discharge Pipeline | $3,997 | $3,984 | $3,972 | $3,959 | $3,946 | $3,933 | $3,921 | $3,908 | $3,895 | $3,883 | $3,870 | $3,857 | $47,125 | $3,625 | $43,500 |
| 20 - Wastewater Discharge Elimination & Reuse | $6,486 | $6,473 | $6,460 | $6,447 | $6,434 | $6,421 | $6,408 | $6,395 | $6,382 | $6,369 | $6,356 | $6,343 | $76,974 | $5,921 | $71,053 |
| NA - Amortization of Gains on Sales of Emissions Allowances | ($139) | ($130) | ($121) | ($113) | ($104) | ($95) | ($87) | ($78) | ($69) | ($61) | ($52) | ($43) | ($1,092) | ($1,092) | |
| 21 - St. Lucie Turtle Nets | $65,699 | $65,628 | $65,557 | $65,486 | $65,415 | $65,344 | $65,273 | $65,202 | $65,131 | $65,060 | $64,989 | $64,918 | $783,701 | $60,285 | $723,416 |
| 22 - Pipeline Integrity Management | $25,809 | $25,770 | $25,730 | $25,691 | $25,652 | $25,613 | $25,574 | $25,535 | $25,496 | $25,457 | $25,418 | $25,378 | $307,123 | $23,625 | $283,498 |
| 23 - SPCC - Spill Prevention, Control & Countermeasures | $139,877 | $139,673 | $139,468 | $139,264 | $139,059 | $152,778 | $166,476 | $166,231 | $165,987 | $165,742 | $165,497 | $165,252 | $1,845,303 | $141,946 | $1,703,357 |
| 24 - Manatee Reburn | $257,995 | $257,452 | $256,909 | $257,192 | $257,472 | $256,927 | $256,381 | $255,836 | $255,290 | $254,744 | $254,199 | $253,653 | $3,074,050 | $3,074,050 | |
| 25 - Pt. Everglades ESP Technology | $1,453,577 | $1,443,195 | $1,432,814 | $1,422,432 | $1,412,050 | $1,401,668 | $1,391,286 | $1,380,905 | $1,370,523 | $1,360,141 | $1,349,759 | $1,339,378 | $16,757,728 | $16,757,728 | |
| 26 - UST Remove/Replacement | $747 | $746 | $744 | $742 | $741 | $739 | $738 | $736 | $735 | $733 | $731 | $730 | $8,863 | $682 | $8,181 |
| 31 - Clean Air Interstate Rule (CAIR) Compliance | $4,755,985 | $4,748,139 | $4,741,036 | $4,733,934 | $4,726,831 | $4,719,729 | $4,712,627 | $4,705,524 | $4,698,422 | $4,691,319 | $4,684,217 | $4,679,384 | $56,597,147 | $4,353,627 | $52,243,520 |
| 33 - MATS Project | $942,786 | $942,358 | $944,073 | $946,164 | $947,864 | $949,558 | $951,246 | $952,928 | $954,604 | $956,274 | $957,938 | $962,169 | $11,407,958 | $877,535 | $10,530,423 |
| 35 - Martin Plant Drinking Water System Compliance | $1,982 | $1,979 | $1,975 | $1,972 | $1,969 | $1,966 | $1,963 | $1,959 | $1,956 | $1,953 | $1,950 | $1,947 | $23,571 | $1,813 | $21,758 |
| 36 - Low-Level Radioactive Waste Storage | $155,628 | $155,425 | $155,222 | $155,019 | $154,815 | $154,612 | $154,409 | $154,206 | $154,003 | $153,800 | $153,596 | $153,393 | $1,854,128 | $142,625 | $1,711,503 |
| 37 - DeSoto Next Generation Solar Energy Center | $1,301,254 | $1,297,635 | $1,294,016 | $1,290,424 | $1,286,832 | $1,283,213 | $1,279,594 | $1,275,975 | $1,272,356 | $1,268,737 | $1,264,834 | $1,260,884 | $15,375,753 | $1,182,750 | $14,193,002 |
| 38 - Space Coast Next Generation Solar Energy Center | $610,785 | $609,118 | $607,452 | $605,785 | $604,119 | $602,434 | $600,750 | $599,083 | $597,417 | $595,751 | $594,086 | $592,421 | $7,219,202 | $555,323 | $6,663,879 |
| 39 - Martin Next Generation Solar Energy Center | $3,760,208 | $3,750,090 | $3,739,972 | $3,730,054 | $3,720,842 | $3,712,817 | $3,704,088 | $3,695,613 | $3,687,136 | $3,677,011 | $3,666,887 | $3,658,324 | $44,503,043 | $3,423,311 | $41,079,732 |
| 41 - Manatee Temporary Heating System | $38,854 | $38,579 | $38,304 | $38,029 | $37,753 | $37,478 | $37,203 | $36,927 | $36,652 | $36,377 | $36,102 | $35,826 | $448,084 | $34,468 | $413,616 |
| 42 - Turkey Point Cooling Canal Monitoring Plan | $80,140 | $80,175 | $80,070 | $79,966 | $80,347 | $80,729 | $80,623 | $80,517 | $80,830 | $81,144 | $81,037 | $113,943 | $999,521 | $76,886 | $922,635 |
| 44 - Martin Plant Barley Barber Swamp Iron Mitigation | $1,447 | $1,445 | $1,443 | $1,440 | $1,438 | $1,436 | $1,434 | $1,431 | $1,429 | $1,427 | $1,425 | $1,422 | $17,217 | | $17,217 |
| 45 - 800 MW Unit ESP | $2,037,038 | $2,033,444 | $2,029,850 | $2,027,637 | $2,025,741 | $2,022,462 | $2,018,867 | $2,015,271 | $2,011,676 | $2,008,080 | $2,004,484 | $2,001,336 | $24,235,887 | | $24,235,887 |
| 2. Total Investment Projects - Recoverable Costs | $15,834,126 | $15,794,664 | $15,757,949 | $15,724,644 | $15,692,453 | $15,672,512 | $15,651,037 | $15,616,692 | $15,582,754 | $15,546,357 | $15,509,221 | $15,512,612 | $187,895,022 | $31,454,780 | $156,440,243 |

Note: Totals may not add due to rounding.

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

FORM: 42-3P

JANUARY 2016 THROUGH DECEMBER 2016
CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 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 Investment Projects - Recoverable Costs | $15,834,126 | $15,794,664 | $15,757,949 | $15,724,644 | $15,692,453 | $15,672,512 | $15,651,037 | $15,616,692 | $15,582,754 | $15,546,357 | $15,509,221 | $15,512,612 | $187,895,022 |
| 3. Recoverable Costs Allocated to Energy | $2,687,962 | $2,674,955 | $2,662,159 | $2,650,834 | $2,639,568 | $2,628,034 | $2,616,407 | $2,603,789 | $2,591,203 | $2,578,427 | $2,565,595 | $2,555,846 | $31,454,780 |
| 4. Recoverable Costs Allocated to Demand | $13,146,165 | $13,119,709 | $13,095,790 | $13,073,810 | $13,052,885 | $13,044,478 | $13,034,631 | $13,012,902 | $12,991,552 | $12,967,930 | $12,943,626 | $12,956,766 | $156,440,243 |
| 5. Retail Energy Jurisdictional Factor | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | |
| 6. Retail Demand Jurisdictional Factor | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | |
| 7. Jurisdictional Energy Recoverable Costs | $2,550,530 | $2,538,188 | $2,526,047 | $2,515,301 | $2,504,611 | $2,493,667 | $2,482,634 | $2,470,661 | $2,458,718 | $2,446,596 | $2,434,420 | $2,425,169 | $29,846,543 |
| 8. Jurisdictional Demand Recoverable Costs | $12,446,139 | $12,421,093 | $12,398,447 | $12,377,638 | $12,357,827 | $12,349,868 | $12,340,545 | $12,319,973 | $12,299,760 | $12,277,396 | $12,254,386 | $12,266,826 | $148,109,898 |
| 9. Total Jurisdictional Recoverable Costs for Investment Projects | $14,996,670 | $14,959,281 | $14,924,494 | $14,892,939 | $14,862,438 | $14,843,535 | $14,823,179 | $14,790,635 | $14,758,478 | $14,723,992 | $14,688,806 | $14,691,995 | $177,956,440 |

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2 - Low NOX Burner Technology** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | $2,563,376 | N/A |
| 3. Less: Accumulated Depreciation | $2,136,815 | $2,142,156 | $2,147,496 | $2,152,836 | $2,158,177 | $2,163,517 | $2,168,857 | $2,174,198 | $2,179,538 | $2,184,879 | $2,190,219 | $2,195,559 | $2,200,900 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $426,561 | $421,221 | $415,880 | $410,540 | $405,200 | $399,859 | $394,519 | $389,179 | $383,838 | $378,498 | $373,158 | $367,817 | $362,477 | N/A |
| 6. Average Net Investment | | $423,891 | $418,551 | $413,210 | $407,870 | $402,530 | $397,189 | $391,849 | $386,508 | $381,168 | $375,828 | $370,487 | $365,147 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $2,772 | $2,737 | $2,702 | $2,667 | $2,632 | $2,597 | $2,562 | $2,528 | $2,493 | $2,458 | $2,423 | $2,388 | $30,959 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $526 | $520 | $513 | $507 | $500 | $493 | $487 | $480 | $473 | $467 | $460 | $454 | $5,880 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $5,340 | $64,084 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $8,639 | $8,597 | $8,556 | $8,514 | $8,473 | $8,431 | $8,389 | $8,348 | $8,306 | $8,265 | $8,223 | $8,182 | $100,923 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **3b - Continuous Emission Monitoring Systems** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $120,576 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $120,576 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $6,383,526 | $6,383,526 | $6,383,526 | $6,383,526 | $6,504,102 | $6,504,102 | $6,504,102 | $6,504,102 | $6,504,102 | $6,504,102 | $6,504,102 | $6,504,102 | $6,504,102 | N/A |
| 3. Less: Accumulated Depreciation | $3,331,638 | $3,350,212 | $3,368,786 | $3,387,360 | $3,406,064 | $3,424,899 | $3,443,734 | $3,462,569 | $3,481,404 | $3,500,239 | $3,519,074 | $3,537,909 | $3,556,744 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $3,051,887 | $3,033,314 | $3,014,740 | $2,996,166 | $3,098,038 | $3,079,203 | $3,060,368 | $3,041,533 | $3,022,698 | $3,003,863 | $2,985,028 | $2,966,193 | $2,947,358 | N/A |
| 6. Average Net Investment | | $3,042,600 | $3,024,027 | $3,005,453 | $3,047,102 | $3,088,620 | $3,069,785 | $3,050,950 | $3,032,115 | $3,013,280 | $2,994,445 | $2,975,610 | $2,956,775 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $19,897 | $19,775 | $19,654 | $19,926 | $20,198 | $20,074 | $19,951 | $19,828 | $19,705 | $19,582 | $19,459 | $19,335 | $237,384 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $3,779 | $3,756 | $3,733 | $3,785 | $3,836 | $3,813 | $3,789 | $3,766 | $3,742 | $3,719 | $3,696 | $3,672 | $45,086 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $18,574 | $18,574 | $18,574 | $18,704 | $18,835 | $18,835 | $18,835 | $18,835 | $18,835 | $18,835 | $18,835 | $18,835 | $225,106 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $42,249 | $42,105 | $41,960 | $42,415 | $42,869 | $42,722 | $42,576 | $42,429 | $42,282 | $42,136 | $41,989 | $41,843 | $507,575 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **4b - Clean Closure Equivalency** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | $21,799 | N/A |
| 3. Less: Accumulated Depreciation | $14,365 | $14,404 | $14,442 | $14,480 | $14,518 | $14,556 | $14,594 | $14,633 | $14,671 | $14,709 | $14,747 | $14,785 | $14,823 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $7,434 | $7,396 | $7,358 | $7,319 | $7,281 | $7,243 | $7,205 | $7,167 | $7,129 | $7,090 | $7,052 | $7,014 | $6,976 | N/A |
| 6. Average Net Investment | | $7,415 | $7,377 | $7,338 | $7,300 | $7,262 | $7,224 | $7,186 | $7,148 | $7,110 | $7,071 | $7,033 | $6,995 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $48 | $48 | $48 | $48 | $47 | $47 | $47 | $47 | $46 | $46 | $46 | $46 | $565 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $107 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $458 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $96 | $96 | $95 | $95 | $95 | $94 | $94 | $94 | $93 | $93 | $93 | $93 | $1,131 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **5b - Maintenance of Stationary Above Ground Fuel Storage Tanks** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | $15,897,715 | N/A |
| 3. Less: Accumulated Depreciation | $3,185,430 | $3,216,868 | $3,248,307 | $3,279,745 | $3,311,183 | $3,342,622 | $3,374,060 | $3,405,499 | $3,436,937 | $3,468,375 | $3,499,814 | $3,531,252 | $3,562,690 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $12,712,285 | $12,680,847 | $12,649,409 | $12,617,970 | $12,586,532 | $12,555,093 | $12,523,655 | $12,492,217 | $12,460,778 | $12,429,340 | $12,397,902 | $12,366,463 | $12,335,025 | N/A |
| 6. Average Net Investment | | $12,696,566 | $12,665,128 | $12,633,689 | $12,602,251 | $12,570,813 | $12,539,374 | $12,507,936 | $12,476,498 | $12,445,059 | $12,413,621 | $12,382,182 | $12,350,744 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $83,027 | $82,822 | $82,616 | $82,411 | $82,205 | $81,999 | $81,794 | $81,588 | $81,383 | $81,177 | $80,972 | $80,766 | $982,760 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $15,769 | $15,730 | $15,691 | $15,652 | $15,613 | $15,574 | $15,535 | $15,496 | $15,457 | $15,418 | $15,379 | $15,340 | $186,653 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $31,438 | $377,260 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $130,235 | $129,990 | $129,746 | $129,501 | $129,256 | $129,012 | $128,767 | $128,522 | $128,278 | $128,033 | $127,789 | $127,544 | $1,546,673 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **7 - Relocate Turbine Lube Oil Underground Piping to Above Ground** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $25,367 | $25,429 | $25,491 | $25,553 | $25,615 | $25,677 | $25,739 | $25,801 | $25,864 | $25,926 | $25,988 | $26,050 | $26,112 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $5,663 | $5,601 | $5,539 | $5,477 | $5,415 | $5,353 | $5,291 | $5,229 | $5,166 | $5,104 | $5,042 | $4,980 | $4,918 | N/A |
| 6. Average Net Investment | | $5,632 | $5,570 | $5,508 | $5,446 | $5,384 | $5,322 | $5,260 | $5,198 | $5,135 | $5,073 | $5,011 | $4,949 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $37 | $36 | $36 | $36 | $35 | $35 | $34 | $34 | $34 | $33 | $33 | $32 | $415 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $6 | $6 | $6 | $6 | $6 | $79 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $62 | $745 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $106 | $105 | $105 | $104 | $104 | $103 | $103 | $103 | $102 | $102 | $101 | $101 | $1,239 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
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JANUARY 2016 THROUGH DECEMBER 2016

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **8b - Oil Spill Clean-up/Response Equipment** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $150,720 | $0 | $0 | ($2,154) | $55,584 | $204,150 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($2,154) | ($9,728) | ($11,882) |
| d. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2. Plant-In-Service/Depreciation Base [a] | $857,637 | $857,637 | $857,637 | $857,637 | $857,637 | $857,637 | $857,637 | $857,637 | $1,008,357 | $1,008,357 | $1,008,357 | $1,006,203 | $1,061,787 | N/A |
| 3. Less: Accumulated Depreciation | $131,178 | $137,581 | $143,985 | $150,389 | $156,792 | $163,196 | $169,600 | $176,003 | $182,627 | $189,470 | $196,313 | $200,972 | $198,491 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $726,459 | $720,056 | $713,652 | $707,248 | $700,845 | $694,441 | $688,037 | $681,634 | $825,730 | $818,887 | $812,044 | $805,230 | $863,296 | N/A |
| 6. Average Net Investment | | $723,257 | $716,854 | $710,450 | $704,046 | $697,643 | $691,239 | $684,835 | $753,682 | $822,309 | $815,465 | $808,637 | $834,263 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $4,730 | $4,688 | $4,646 | $4,604 | $4,562 | $4,520 | $4,478 | $4,929 | $5,377 | $5,333 | $5,288 | $5,456 | $58,610 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $898 | $890 | $882 | $874 | $866 | $859 | $851 | $936 | $1,021 | $1,013 | $1,004 | $1,036 | $11,132 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $6,404 | $6,404 | $6,404 | $6,404 | $6,404 | $6,404 | $6,404 | $6,623 | $6,843 | $6,843 | $6,813 | $7,247 | $79,196 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $12,032 | $11,982 | $11,932 | $11,882 | $11,832 | $11,782 | $11,733 | $12,488 | $13,242 | $13,189 | $13,106 | $13,738 | $148,938 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **10 - Relocate Storm Water Runoff** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $61,707 | $61,884 | $62,060 | $62,237 | $62,414 | $62,590 | $62,767 | $62,944 | $63,121 | $63,297 | $63,474 | $63,651 | $63,827 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $56,087 | $55,910 | $55,733 | $55,557 | $55,380 | $55,203 | $55,027 | $54,850 | $54,673 | $54,497 | $54,320 | $54,143 | $53,967 | N/A |
| 6. Average Net Investment | | $55,998 | $55,822 | $55,645 | $55,468 | $55,292 | $55,115 | $54,938 | $54,762 | $54,585 | $54,408 | $54,232 | $54,055 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $366 | $365 | $364 | $363 | $362 | $360 | $359 | $358 | $357 | $356 | $355 | $353 | $4,318 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $70 | $69 | $69 | $69 | $69 | $68 | $68 | $68 | $68 | $68 | $67 | $67 | $820 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $177 | $2,120 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $612 | $611 | $610 | $608 | $607 | $606 | $604 | $603 | $601 | $600 | $599 | $597 | $7,258 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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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** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $549,628 | $551,260 | $552,892 | $554,525 | $556,157 | $557,789 | $559,422 | $561,054 | $562,686 | $564,319 | $565,951 | $567,583 | $569,216 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $304,696 | $303,064 | $301,431 | $299,799 | $298,167 | $296,534 | $294,902 | $293,270 | $291,637 | $290,005 | $288,373 | $286,740 | $285,108 | N/A |
| 6. Average Net Investment | | $303,880 | $302,247 | $300,615 | $298,983 | $297,350 | $295,718 | $294,086 | $292,453 | $290,821 | $289,189 | $287,556 | $285,924 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $1,987 | $1,977 | $1,966 | $1,955 | $1,944 | $1,934 | $1,923 | $1,912 | $1,902 | $1,891 | $1,880 | $1,870 | $23,142 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $377 | $375 | $373 | $371 | $369 | $367 | $365 | $363 | $361 | $359 | $357 | $355 | $4,395 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $1,632 | $19,588 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $3,997 | $3,984 | $3,972 | $3,959 | $3,946 | $3,933 | $3,921 | $3,908 | $3,895 | $3,883 | $3,870 | $3,857 | $47,125 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $152,045 | $153,717 | $155,389 | $157,060 | $158,732 | $160,404 | $162,076 | $163,747 | $165,419 | $167,091 | $168,763 | $170,434 | $172,106 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $619,532 | $617,860 | $616,188 | $614,516 | $612,845 | $611,173 | $609,501 | $607,829 | $606,158 | $604,486 | $602,814 | $601,142 | $599,471 | N/A |
| 6. Average Net Investment | | $618,696 | $617,024 | $615,352 | $613,681 | $612,009 | $610,337 | $608,665 | $606,994 | $605,322 | $603,650 | $601,978 | $600,307 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $4,046 | $4,035 | $4,024 | $4,013 | $4,002 | $3,991 | $3,980 | $3,969 | $3,958 | $3,947 | $3,937 | $3,926 | $47,829 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $768 | $766 | $764 | $762 | $760 | $758 | $756 | $754 | $752 | $750 | $748 | $746 | $9,084 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $1,672 | $20,061 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $6,486 | $6,473 | $6,460 | $6,447 | $6,434 | $6,421 | $6,408 | $6,395 | $6,382 | $6,369 | $6,356 | $6,343 | $76,974 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **21 - St. Lucie Turtle Nets** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | $6,078,732 | N/A |
| 3. Less: Accumulated Depreciation | ($1,197,124) | ($1,188,006) | ($1,178,888) | ($1,169,770) | ($1,160,652) | ($1,151,534) | ($1,142,416) | ($1,133,298) | ($1,124,180) | ($1,115,062) | ($1,105,943) | ($1,096,825) | ($1,087,707) | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $7,275,856 | $7,266,738 | $7,257,620 | $7,248,502 | $7,239,384 | $7,230,266 | $7,221,148 | $7,212,030 | $7,202,912 | $7,193,793 | $7,184,675 | $7,175,557 | $7,166,439 | N/A |
| 6. Average Net Investment | | $7,271,297 | $7,262,179 | $7,253,061 | $7,243,943 | $7,234,825 | $7,225,707 | $7,216,589 | $7,207,471 | $7,198,353 | $7,189,234 | $7,180,116 | $7,170,998 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $47,550 | $47,490 | $47,430 | $47,371 | $47,311 | $47,251 | $47,192 | $47,132 | $47,073 | $47,013 | $46,953 | $46,894 | $566,660 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $9,031 | $9,020 | $9,008 | $8,997 | $8,986 | $8,974 | $8,963 | $8,952 | $8,940 | $8,929 | $8,918 | $8,906 | $107,624 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $9,118 | $109,417 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $65,699 | $65,628 | $65,557 | $65,486 | $65,415 | $65,344 | $65,273 | $65,202 | $65,131 | $65,060 | $64,989 | $64,918 | $783,701 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **22 - Pipeline Integrity Management** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $2,872,791 | $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 | N/A |
| 3. Less: Accumulated Depreciation | $199,620 | $204,647 | $209,675 | $214,702 | $219,730 | $224,757 | $229,784 | $234,812 | $239,839 | $244,867 | $249,894 | $254,921 | $259,949 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $2,673,171 | $2,668,144 | $2,663,116 | $2,658,089 | $2,653,062 | $2,648,034 | $2,643,007 | $2,637,980 | $2,632,952 | $2,627,925 | $2,622,897 | $2,617,870 | $2,612,843 | N/A |
| 6. Average Net Investment | | $2,670,658 | $2,665,630 | $2,660,603 | $2,655,575 | $2,650,548 | $2,645,521 | $2,640,493 | $2,635,466 | $2,630,438 | $2,625,411 | $2,620,384 | $2,615,356 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $17,464 | $17,432 | $17,399 | $17,366 | $17,333 | $17,300 | $17,267 | $17,234 | $17,201 | $17,168 | $17,136 | $17,103 | $207,403 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $3,317 | $3,311 | $3,304 | $3,298 | $3,292 | $3,286 | $3,279 | $3,273 | $3,267 | $3,261 | $3,255 | $3,248 | $39,391 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $5,027 | $5,027 | $5,027 | $5,027 | $5,027 | $5,027 | $5,027 | $5,027 | $5,027 | $5,027 | $5,027 | $5,027 | $60,329 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $25,809 | $25,770 | $25,730 | $25,691 | $25,652 | $25,613 | $25,574 | $25,535 | $25,496 | $25,457 | $25,418 | $25,378 | $307,123 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
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| | Beginning of Period Amount | January Estimated | February Estimated | March Estimated | April Estimated | May Estimated | June Estimated | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **23 - SPCC - Spill Prevention, Control & Countermeasures** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $6,667 | $6,667 | $6,667 | $6,667 | $6,667 | $2,930,328 | $6,667 | $6,667 | $6,667 | $6,667 | $6,667 | $6,663 | $3,003,661 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $16,123,727 | $16,130,394 | $16,137,061 | $16,143,728 | $16,150,395 | $16,157,062 | $19,087,390 | $19,094,057 | $19,100,724 | $19,107,391 | $19,114,058 | $19,120,725 | $19,127,388 | N/A |
| 3. Less: Accumulated Depreciation | $2,540,621 | $2,574,911 | $2,609,211 | $2,643,522 | $2,677,843 | $2,712,175 | $2,749,076 | $2,788,546 | $2,828,026 | $2,867,516 | $2,907,018 | $2,946,529 | $2,986,052 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $13,583,106 | $13,555,483 | $13,527,850 | $13,500,206 | $13,472,551 | $13,444,886 | $16,338,314 | $16,305,511 | $16,272,698 | $16,239,874 | $16,207,040 | $16,174,195 | $16,141,336 | N/A |
| 6. Average Net Investment | | $13,569,294 | $13,541,666 | $13,514,028 | $13,486,379 | $13,458,719 | $14,891,600 | $16,321,912 | $16,289,104 | $16,256,286 | $16,223,457 | $16,190,618 | $16,157,766 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $88,734 | $88,554 | $88,373 | $88,192 | $88,011 | $97,381 | $106,735 | $106,520 | $106,306 | $106,091 | $105,876 | $105,661 | $1,176,436 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $16,853 | $16,819 | $16,784 | $16,750 | $16,716 | $18,495 | $20,272 | $20,231 | $20,190 | $20,150 | $20,109 | $20,068 | $223,437 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $34,290 | $34,300 | $34,311 | $34,321 | $34,332 | $36,901 | $39,470 | $39,480 | $39,491 | $39,501 | $39,512 | $39,522 | $445,431 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $139,877 | $139,673 | $139,468 | $139,264 | $139,059 | $152,778 | $166,476 | $166,231 | $165,987 | $165,742 | $165,497 | $165,252 | $1,845,303 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $165,792 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $165,792 |
| b. Clearings to Plant | | $0 | $0 | $0 | $166,696 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $166,696 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $32,193,902 | $32,193,902 | $32,193,902 | $32,193,902 | $32,360,598 | $32,360,598 | $32,360,598 | $32,360,598 | $32,360,598 | $32,360,598 | $32,360,598 | $32,360,598 | $32,360,598 | N/A |
| 3. Less: Accumulated Depreciation | $7,968,586 | $8,038,340 | $8,108,093 | $8,177,847 | $8,247,781 | $8,317,895 | $8,388,010 | $8,458,125 | $8,528,239 | $8,598,354 | $8,668,469 | $8,738,583 | $8,808,698 | N/A |
| 4. CWIP - Non Interest Bearing | $904 | $904 | $904 | $904 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $24,226,220 | $24,156,466 | $24,086,713 | $24,016,959 | $24,112,817 | $24,042,703 | $23,972,588 | $23,902,473 | $23,832,359 | $23,762,244 | $23,692,129 | $23,622,015 | $23,551,900 | N/A |
| 6. Average Net Investment | | $24,191,343 | $24,121,589 | $24,051,836 | $24,064,888 | $24,077,760 | $24,007,645 | $23,937,531 | $23,867,416 | $23,797,301 | $23,727,187 | $23,657,072 | $23,586,958 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $158,196 | $157,740 | $157,284 | $157,369 | $157,453 | $156,995 | $156,536 | $156,078 | $155,619 | $155,161 | $154,702 | $154,244 | $1,877,374 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $30,046 | $29,959 | $29,872 | $29,889 | $29,905 | $29,817 | $29,730 | $29,643 | $29,556 | $29,469 | $29,382 | $29,295 | $356,564 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $69,753 | $69,753 | $69,753 | $69,934 | $70,115 | $70,115 | $70,115 | $70,115 | $70,115 | $70,115 | $70,115 | $70,115 | $840,111 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $257,995 | $257,452 | $256,909 | $257,192 | $257,472 | $256,927 | $256,381 | $255,836 | $255,290 | $254,744 | $254,199 | $253,653 | $3,074,050 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **25 - Pt. Everglades ESP Technology** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| d. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2. Plant-In-Service/Depreciation Base [a] | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 3. Less: Accumulated Depreciation | ($16,010,241) | ($14,676,055) | ($13,341,868) | ($12,007,681) | ($10,673,495) | ($9,339,308) | ($8,005,122) | ($6,670,935) | ($5,336,748) | ($4,002,562) | ($2,668,375) | ($1,334,188) | ($2) | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $16,010,241 | $14,676,055 | $13,341,868 | $12,007,681 | $10,673,495 | $9,339,308 | $8,005,122 | $6,670,935 | $5,336,748 | $4,002,562 | $2,668,375 | $1,334,188 | $2 | N/A |
| 6. Average Net Investment | | $15,343,148 | $14,008,961 | $12,674,775 | $11,340,588 | $10,006,402 | $8,672,215 | $7,338,028 | $6,003,842 | $4,669,655 | $3,335,468 | $2,001,282 | $667,095 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $100,334 | $91,610 | $82,885 | $74,160 | $65,435 | $56,711 | $47,986 | $39,261 | $30,537 | $21,812 | $13,087 | $4,362 | $628,180 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $19,056 | $17,399 | $15,742 | $14,085 | $12,428 | $10,771 | $9,114 | $7,457 | $5,800 | $4,143 | $2,486 | $829 | $119,308 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $1,334,187 | $16,010,240 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $1,453,577 | $1,443,195 | $1,432,814 | $1,422,432 | $1,412,050 | $1,401,668 | $1,391,286 | $1,380,905 | $1,370,523 | $1,360,141 | $1,349,759 | $1,339,378 | $16,757,728 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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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** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $45,283 | $45,485 | $45,688 | $45,890 | $46,092 | $46,294 | $46,496 | $46,698 | $46,900 | $47,102 | $47,304 | $47,506 | $47,708 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $70,163 | $69,961 | $69,759 | $69,557 | $69,355 | $69,153 | $68,951 | $68,749 | $68,547 | $68,345 | $68,143 | $67,941 | $67,739 | N/A |
| 6. Average Net Investment | | $70,062 | $69,860 | $69,658 | $69,456 | $69,254 | $69,052 | $68,850 | $68,648 | $68,446 | $68,244 | $68,042 | $67,840 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $458 | $457 | $456 | $454 | $453 | $452 | $450 | $449 | $448 | $446 | $445 | $444 | $5,411 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $87 | $87 | $87 | $86 | $86 | $86 | $86 | $85 | $85 | $85 | $85 | $84 | $1,028 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $202 | $2,424 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $747 | $746 | $744 | $742 | $741 | $739 | $738 | $736 | $735 | $733 | $731 | $730 | $8,863 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **31 - Clean Air Interstate Rule (CAIR) Compliance** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $191,186 | $191,186 | $191,186 | $191,186 | $191,186 | $191,186 | $191,186 | $191,186 | $191,186 | $191,186 | $191,186 | $2,103,046 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,103,046 | $2,103,046 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $526,362,444 | $526,362,444 | $526,362,444 | $526,362,444 | $526,362,444 | $526,362,444 | $526,362,444 | $526,362,444 | $526,362,444 | $526,362,444 | $526,362,444 | $526,362,444 | $528,465,490 | N/A |
| 3. Less: Accumulated Depreciation | $56,477,922 | $57,581,863 | $58,685,804 | $59,789,745 | $60,893,686 | $61,997,627 | $63,101,568 | $64,205,510 | $65,309,451 | $66,413,392 | $67,517,333 | $68,621,274 | $69,727,493 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $191,186 | $382,372 | $573,558 | $764,744 | $955,930 | $1,147,116 | $1,338,302 | $1,529,488 | $1,720,674 | $1,911,860 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $469,884,522 | $468,780,581 | $467,867,826 | $466,955,071 | $466,042,315 | $465,129,560 | $464,216,805 | $463,304,050 | $462,391,295 | $461,478,540 | $460,565,785 | $459,653,030 | $458,737,996 | N/A |
| 6. Average Net Investment | | $469,332,551 | $468,324,203 | $467,411,448 | $466,498,693 | $465,585,938 | $464,673,183 | $463,760,428 | $462,847,673 | $461,934,917 | $461,022,162 | $460,109,407 | $459,195,513 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $3,069,133 | $3,062,539 | $3,056,570 | $3,050,601 | $3,044,633 | $3,038,664 | $3,032,695 | $3,026,726 | $3,020,757 | $3,014,788 | $3,008,820 | $3,002,843 | $36,428,770 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $582,911 | $581,659 | $580,525 | $579,391 | $578,258 | $577,124 | $575,990 | $574,857 | $573,723 | $572,590 | $571,456 | $570,321 | $6,918,805 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,103,941 | $1,103,941 | $1,103,941 | $1,103,941 | $1,103,941 | $1,103,941 | $1,103,941 | $1,103,941 | $1,103,941 | $1,103,941 | $1,103,941 | $1,106,219 | $13,249,572 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $4,755,985 | $4,748,139 | $4,741,036 | $4,733,934 | $4,726,831 | $4,719,729 | $4,712,627 | $4,705,524 | $4,698,422 | $4,691,319 | $4,684,217 | $4,679,384 | $56,597,147 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **33 - MATS Project** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $354,320 | $354,320 | $354,320 | $354,320 | $354,320 | $354,320 | $354,320 | $354,320 | $354,320 | $354,320 | $872,067 | $4,415,267 |
| b. Clearings to Plant | | $0 | $0 | $708,640 | $354,320 | $354,320 | $354,320 | $354,320 | $354,320 | $354,320 | $354,320 | $354,320 | $872,067 | $4,415,267 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $107,220,712 | $107,220,712 | $107,220,712 | $107,929,352 | $108,283,672 | $108,637,992 | $108,992,312 | $109,346,632 | $109,700,952 | $110,055,272 | $110,409,592 | $110,763,912 | $111,635,979 | N/A |
| 3. Less: Accumulated Depreciation | $15,787,827 | $16,020,045 | $16,252,263 | $16,485,248 | $16,719,385 | $16,954,290 | $17,189,962 | $17,426,402 | $17,663,610 | $17,901,585 | $18,140,329 | $18,379,839 | $18,620,679 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $354,320 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $91,432,885 | $91,200,667 | $91,322,770 | $91,444,104 | $91,564,287 | $91,683,703 | $91,802,350 | $91,920,230 | $92,037,342 | $92,153,687 | $92,269,264 | $92,384,073 | $93,015,300 | N/A |
| 6. Average Net Investment | | $91,316,776 | $91,261,719 | $91,383,437 | $91,504,196 | $91,623,995 | $91,743,026 | $91,861,290 | $91,978,786 | $92,095,515 | $92,211,475 | $92,326,668 | $92,699,687 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $597,153 | $596,793 | $597,589 | $598,379 | $599,162 | $599,940 | $600,714 | $601,482 | $602,245 | $603,004 | $603,757 | $606,196 | $7,206,414 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $113,415 | $113,347 | $113,498 | $113,648 | $113,797 | $113,945 | $114,092 | $114,238 | $114,383 | $114,527 | $114,670 | $115,133 | $1,368,692 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $232,218 | $232,218 | $232,985 | $234,137 | $234,905 | $235,672 | $236,440 | $237,208 | $237,975 | $238,743 | $239,511 | $240,839 | $2,832,852 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $942,786 | $942,358 | $944,073 | $946,164 | $947,864 | $949,558 | $951,246 | $952,928 | $954,604 | $956,274 | $957,938 | $962,169 | $11,407,958 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $33,427 | $33,839 | $34,251 | $34,662 | $35,074 | $35,486 | $35,898 | $36,310 | $36,722 | $37,134 | $37,546 | $37,958 | $38,370 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $201,965 | $201,553 | $201,141 | $200,729 | $200,317 | $199,905 | $199,493 | $199,081 | $198,669 | $198,257 | $197,845 | $197,433 | $197,022 | N/A |
| 6. Average Net Investment | | $201,759 | $201,347 | $200,935 | $200,523 | $200,111 | $199,699 | $199,287 | $198,875 | $198,463 | $198,051 | $197,639 | $197,227 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $1,319 | $1,317 | $1,314 | $1,311 | $1,309 | $1,306 | $1,303 | $1,301 | $1,298 | $1,295 | $1,292 | $1,290 | $15,655 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $251 | $250 | $250 | $249 | $249 | $248 | $248 | $247 | $246 | $246 | $245 | $245 | $2,973 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $412 | $4,943 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $1,982 | $1,979 | $1,975 | $1,972 | $1,969 | $1,966 | $1,963 | $1,959 | $1,956 | $1,953 | $1,950 | $1,947 | $23,571 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | $17,407,593 | N/A |
| 3. Less: Accumulated Depreciation | $750,035 | $776,147 | $802,258 | $828,369 | $854,481 | $880,592 | $906,703 | $932,815 | $958,926 | $985,038 | $1,011,149 | $1,037,260 | $1,063,372 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $16,657,557 | $16,631,446 | $16,605,335 | $16,579,223 | $16,553,112 | $16,527,000 | $16,500,889 | $16,474,778 | $16,448,666 | $16,422,555 | $16,396,444 | $16,370,332 | $16,344,221 | N/A |
| 6. Average Net Investment | | $16,644,502 | $16,618,390 | $16,592,279 | $16,566,168 | $16,540,056 | $16,513,945 | $16,487,833 | $16,461,722 | $16,435,611 | $16,409,499 | $16,383,388 | $16,357,276 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $108,844 | $108,674 | $108,503 | $108,332 | $108,161 | $107,991 | $107,820 | $107,649 | $107,478 | $107,308 | $107,137 | $106,966 | $1,294,862 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $20,672 | $20,640 | $20,608 | $20,575 | $20,543 | $20,510 | $20,478 | $20,445 | $20,413 | $20,381 | $20,348 | $20,316 | $245,929 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $26,111 | $26,111 | $26,111 | $26,111 | $26,111 | $26,111 | $26,111 | $26,111 | $26,111 | $26,111 | $26,111 | $26,111 | $313,337 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $155,628 | $155,425 | $155,222 | $155,019 | $154,815 | $154,612 | $154,409 | $154,206 | $154,003 | $153,800 | $153,596 | $153,393 | $1,854,128 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **37 - DeSoto Next Generation Solar Energy Center** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $5,024 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $5,024 |
| b. Clearings to Plant | | $0 | $0 | $0 | $5,024 | $0 | $0 | $0 | $0 | $0 | $0 | ($20,537) | ($8,324) | ($23,837) |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($20,537) | ($8,324) | ($28,861) |
| d. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2. Plant-In-Service/Depreciation Base [a] | $153,654,009 | $153,654,009 | $153,654,009 | $153,654,009 | $153,659,033 | $153,659,033 | $153,659,033 | $153,659,033 | $153,659,033 | $153,659,033 | $153,659,033 | $153,638,496 | $153,630,171 | N/A |
| 3. Less: Accumulated Depreciation | $31,343,686 | $31,770,684 | $32,197,682 | $32,624,679 | $33,051,684 | $33,478,696 | $33,905,707 | $34,332,719 | $34,759,730 | $35,186,742 | $35,613,753 | $36,019,942 | $36,438,010 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $122,310,322 | $121,883,325 | $121,456,327 | $121,029,329 | $120,607,349 | $120,180,337 | $119,753,326 | $119,326,314 | $118,899,303 | $118,472,291 | $118,045,280 | $117,618,553 | $117,192,162 | N/A |
| 6. Average Net Investment | | $122,096,824 | $121,669,826 | $121,242,828 | $120,818,339 | $120,393,843 | $119,966,831 | $119,539,820 | $119,112,808 | $118,685,797 | $118,258,785 | $117,831,916 | $117,405,358 | N/A |
| a. Average ITC Balance | | $34,849,953 | $34,727,887 | $34,605,821 | $34,483,755 | $34,361,689 | $34,239,623 | $34,117,557 | $33,995,491 | $33,873,425 | $33,751,359 | $33,629,293 | $33,507,227 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $871,420 | $868,372 | $865,324 | $862,292 | $859,261 | $856,213 | $853,165 | $850,117 | $847,069 | $844,021 | $840,973 | $837,928 | $10,256,153 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $163,232 | $162,661 | $162,090 | $161,522 | $160,954 | $160,383 | $159,813 | $159,242 | $158,671 | $158,100 | $157,529 | $156,959 | $1,921,155 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $420,939 | $420,939 | $420,939 | $420,946 | $420,953 | $420,953 | $420,953 | $420,953 | $420,953 | $420,953 | $420,667 | $420,333 | $5,050,477 |
| b. Amortization [e] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Dismantlement [f] | | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $6,059 | $72,708 |
| 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 Expenses (Lines 7 & 8) | | $1,301,254 | $1,297,635 | $1,294,016 | $1,290,424 | $1,286,832 | $1,283,213 | $1,279,594 | $1,275,975 | $1,272,356 | $1,268,737 | $1,264,834 | $1,260,884 | $15,375,753 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **38 - Space Coast Next Generation Solar Energy Center** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | ($1,310) | $0 | $0 | $0 | $0 | $1,374 | $0 | $65 |
| c. Retirements | | $0 | $0 | $0 | $0 | $0 | ($1,310) | $0 | $0 | $0 | $0 | $0 | $0 | ($1,310) |
| d. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2. Plant-In-Service/Depreciation Base [a] | $70,657,104 | $70,657,104 | $70,657,104 | $70,657,104 | $70,657,104 | $70,657,104 | $70,655,794 | $70,655,794 | $70,655,794 | $70,655,794 | $70,655,794 | $70,657,169 | $70,657,169 | N/A |
| 3. Less: Accumulated Depreciation | $13,539,522 | $13,737,730 | $13,935,937 | $14,134,144 | $14,332,352 | $14,530,559 | $14,727,439 | $14,925,610 | $15,123,781 | $15,321,952 | $15,520,123 | $15,718,296 | $15,916,470 | N/A |
| 4. CWIP - Non Interest Bearing | $1,374 | $1,374 | $1,374 | $1,374 | $1,374 | $1,374 | $1,374 | $1,374 | $1,374 | $1,374 | $1,374 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $57,118,956 | $56,920,748 | $56,722,541 | $56,524,334 | $56,326,126 | $56,127,919 | $55,929,729 | $55,731,558 | $55,533,387 | $55,335,216 | $55,137,045 | $54,938,872 | $54,740,698 | N/A |
| 6. Average Net Investment | | $57,019,852 | $56,821,645 | $56,623,437 | $56,425,230 | $56,227,022 | $56,028,824 | $55,830,644 | $55,632,473 | $55,434,302 | $55,236,131 | $55,037,959 | $54,839,785 | N/A |
| a. Average ITC Balance | | $14,895,867 | $14,844,678 | $14,793,489 | $14,742,300 | $14,691,111 | $14,639,922 | $14,588,733 | $14,537,544 | $14,486,355 | $14,435,166 | $14,383,977 | $14,332,788 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $404,069 | $402,666 | $401,262 | $399,859 | $398,456 | $397,052 | $395,649 | $394,246 | $392,843 | $391,440 | $390,037 | $388,634 | $4,756,212 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $75,772 | $75,508 | $75,245 | $74,982 | $74,719 | $74,456 | $74,192 | $73,929 | $73,666 | $73,403 | $73,140 | $72,877 | $891,889 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $195,295 | $195,295 | $195,295 | $195,295 | $195,295 | $195,277 | $195,259 | $195,259 | $195,259 | $195,259 | $195,261 | $195,262 | $2,343,314 |
| b. Amortization [e] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Dismantlement [f] | | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $2,912 | $34,944 |
| 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 Expenses (Lines 7 & 8) | | $610,785 | $609,118 | $607,452 | $605,785 | $604,119 | $602,434 | $600,750 | $599,083 | $597,417 | $595,751 | $594,086 | $592,421 | $7,219,202 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $51,747 | $181,091 | $357,038 | $0 | $325,955 | $0 | $0 | $0 | $51,747 | $967,578 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $274,208 | $0 | $0 | $0 | $992,860 | $1,267,068 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $422,335,919 | $422,335,919 | $422,335,919 | $422,335,919 | $422,335,919 | $422,335,919 | $422,335,919 | $422,335,919 | $422,610,127 | $422,610,127 | $422,610,127 | $422,610,127 | $423,602,987 | N/A |
| 3. Less: Accumulated Depreciation | $66,117,050 | $67,310,169 | $68,503,289 | $69,696,408 | $70,889,527 | $72,082,647 | $73,275,766 | $74,468,885 | $75,662,382 | $76,856,255 | $78,050,128 | $79,244,002 | $80,439,240 | N/A |
| 4. CWIP - Non Interest Bearing | $299,490 | $299,490 | $299,490 | $299,490 | $351,237 | $532,328 | $889,366 | $889,366 | $941,113 | $941,113 | $941,113 | $941,113 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $356,518,359 | $355,325,239 | $354,132,120 | $352,939,001 | $351,797,628 | $350,785,600 | $349,949,519 | $348,756,399 | $347,888,858 | $346,694,985 | $345,501,111 | $344,307,238 | $343,163,746 | N/A |
| 6. Average Net Investment | | $355,921,799 | $354,728,680 | $353,535,560 | $352,368,315 | $351,291,614 | $350,367,559 | $349,352,959 | $348,322,629 | $347,291,921 | $346,098,048 | $344,904,175 | $343,735,492 | N/A |
| a. Average ITC Balance | | $102,723,505 | $102,379,707 | $102,035,909 | $101,692,111 | $101,348,313 | $101,004,515 | $100,660,717 | $100,316,919 | $99,973,121 | $99,629,323 | $99,285,525 | $98,941,727 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $2,542,630 | $2,534,107 | $2,525,585 | $2,517,232 | $2,509,471 | $2,502,708 | $2,495,354 | $2,487,896 | $2,480,436 | $2,471,909 | $2,463,381 | $2,455,019 | $29,985,727 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $476,210 | $474,614 | $473,018 | $471,454 | $470,002 | $468,741 | $467,366 | $465,972 | $464,578 | $462,981 | $461,383 | $459,818 | $5,616,137 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $1,164,272 | $1,164,272 | $1,164,272 | $1,164,272 | $1,164,272 | $1,164,272 | $1,164,272 | $1,164,649 | $1,165,026 | $1,165,026 | $1,165,026 | $1,166,392 | $13,976,026 |
| b. Amortization [e] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| c. Dismantlement [f] | | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $28,847 | $346,164 |
| 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 Expenses (Lines 7 & 8) | | $3,760,208 | $3,750,090 | $3,739,972 | $3,730,054 | $3,720,842 | $3,712,817 | $3,704,088 | $3,695,613 | $3,687,136 | $3,677,011 | $3,666,887 | $3,658,324 | $44,503,043 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | $7,284,092 | N/A |
| 3. Less: Accumulated Depreciation | $6,819,523 | $6,854,900 | $6,890,277 | $6,925,654 | $6,961,031 | $6,996,408 | $7,031,785 | $7,067,162 | $7,102,539 | $7,137,916 | $7,173,294 | $7,208,671 | $7,244,048 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $464,569 | $429,192 | $393,815 | $358,438 | $323,061 | $287,684 | $252,307 | $216,930 | $181,553 | $146,176 | $110,799 | $75,422 | $40,044 | N/A |
| 6. Average Net Investment | | $446,881 | $411,503 | $376,126 | $340,749 | $305,372 | $269,995 | $234,618 | $199,241 | $163,864 | $128,487 | $93,110 | $57,733 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $2,922 | $2,691 | $2,460 | $2,228 | $1,997 | $1,766 | $1,534 | $1,303 | $1,072 | $840 | $609 | $378 | $19,799 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $555 | $511 | $467 | $423 | $379 | $335 | $291 | $247 | $204 | $160 | $116 | $72 | $3,760 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $35,377 | $424,525 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $38,854 | $38,579 | $38,304 | $38,029 | $37,753 | $37,478 | $37,203 | $36,927 | $36,652 | $36,377 | $36,102 | $35,826 | $448,084 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **42 - Turkey Point Cooling Canal Monitoring Plan** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $30,000 | $0 | $0 | $0 | $104,911 | $0 | $0 | $0 | $90,485 | $0 | $0 | $7,118,412 | $7,343,808 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $8,941,833 | $8,971,833 | $8,971,833 | $8,971,833 | $8,971,833 | $9,076,744 | $9,076,744 | $9,076,744 | $9,076,744 | $9,167,229 | $9,167,229 | $9,167,229 | $16,285,641 | N/A |
| 3. Less: Accumulated Depreciation | $377,672 | $391,107 | $404,565 | $418,023 | $431,481 | $445,017 | $458,632 | $472,247 | $485,862 | $499,545 | $513,296 | $527,047 | $546,137 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $8,564,161 | $8,580,726 | $8,567,268 | $8,553,810 | $8,540,353 | $8,631,727 | $8,618,112 | $8,604,497 | $8,590,882 | $8,667,684 | $8,653,933 | $8,640,182 | $15,739,504 | N/A |
| 6. Average Net Investment | | $8,572,444 | $8,573,997 | $8,560,539 | $8,547,082 | $8,586,040 | $8,624,919 | $8,611,304 | $8,597,689 | $8,629,283 | $8,660,808 | $8,647,058 | $12,189,843 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $56,058 | $56,068 | $55,980 | $55,892 | $56,147 | $56,401 | $56,312 | $56,223 | $56,430 | $56,636 | $56,546 | $79,714 | $698,410 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $10,647 | $10,649 | $10,632 | $10,615 | $10,664 | $10,712 | $10,695 | $10,678 | $10,718 | $10,757 | $10,740 | $15,140 | $132,647 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $13,435 | $13,458 | $13,458 | $13,458 | $13,536 | $13,615 | $13,615 | $13,615 | $13,683 | $13,751 | $13,751 | $19,090 | $168,465 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $80,140 | $80,175 | $80,070 | $79,966 | $80,347 | $80,729 | $80,623 | $80,517 | $80,830 | $81,144 | $81,037 | $113,943 | $999,521 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **44 - Martin Plant Barley Barber Swamp Iron Mitigation** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $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] | $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 | N/A |
| 3. Less: Accumulated Depreciation | $15,655 | $15,944 | $16,232 | $16,520 | $16,809 | $17,097 | $17,385 | $17,673 | $17,962 | $18,250 | $18,538 | $18,826 | $19,115 | N/A |
| 4. CWIP - Non Interest Bearing | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $149,063 | $148,775 | $148,487 | $148,198 | $147,910 | $147,622 | $147,334 | $147,045 | $146,757 | $146,469 | $146,180 | $145,892 | $145,604 | N/A |
| 6. Average Net Investment | | $148,919 | $148,631 | $148,342 | $148,054 | $147,766 | $147,478 | $147,189 | $146,901 | $146,613 | $146,325 | $146,036 | $145,748 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $974 | $972 | $970 | $968 | $966 | $964 | $963 | $961 | $959 | $957 | $955 | $953 | $11,562 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $185 | $185 | $184 | $184 | $184 | $183 | $183 | $182 | $182 | $182 | $181 | $181 | $2,196 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $288 | $3,459 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $1,447 | $1,445 | $1,443 | $1,440 | $1,438 | $1,436 | $1,434 | $1,431 | $1,429 | $1,427 | $1,425 | $1,422 | $17,217 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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** | | | | | | | | | | | | | | |
| 1. Investments | | | | | | | | | | | | | | |
| a. Expenditures/Additions | | $0 | $0 | $0 | $332,940 | $81,389 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $414,329 |
| b. Clearings to Plant | | $0 | $0 | $0 | $80,400 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $414,329 | $494,729 |
| c. Retirements | | $0 | $0 | $0 | $0 | $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] | $214,453,082 | $214,453,082 | $214,453,082 | $214,453,082 | $214,533,482 | $214,533,482 | $214,533,482 | $214,533,482 | $214,533,482 | $214,533,482 | $214,533,482 | $214,533,482 | $214,947,811 | N/A |
| 3. Less: Accumulated Depreciation | $11,878,351 | $12,340,254 | $12,802,157 | $13,264,060 | $13,726,051 | $14,188,128 | $14,650,206 | $15,112,283 | $15,574,361 | $16,036,438 | $16,498,516 | $16,960,593 | $17,423,119 | N/A |
| 4. CWIP - Non Interest Bearing | $80,400 | $80,400 | $80,400 | $80,400 | $332,940 | $414,329 | $414,329 | $414,329 | $414,329 | $414,329 | $414,329 | $414,329 | $0 | N/A |
| 5. Net Investment (Lines 2 - 3 + 4) | $202,655,131 | $202,193,228 | $201,731,324 | $201,269,421 | $201,140,371 | $200,759,682 | $200,297,605 | $199,835,527 | $199,373,450 | $198,911,372 | $198,449,295 | $197,987,217 | $197,524,691 | N/A |
| 6. Average Net Investment | | $202,424,179 | $201,962,276 | $201,500,373 | $201,204,896 | $200,950,026 | $200,528,644 | $200,066,566 | $199,604,489 | $199,142,411 | $198,680,334 | $198,218,256 | $197,755,954 | N/A |
| 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [b][g] | | $1,323,724 | $1,320,703 | $1,317,683 | $1,315,751 | $1,314,084 | $1,311,328 | $1,308,307 | $1,305,285 | $1,302,263 | $1,299,242 | $1,296,220 | $1,293,197 | $15,707,787 |
| b. Debt Component (Line 6 x debt rate x 1/12) [c][g] | | $251,411 | $250,837 | $250,263 | $249,896 | $249,580 | $249,057 | $248,483 | $247,909 | $247,335 | $246,761 | $246,187 | $245,613 | $2,983,332 |
| 8. Investment Expenses | | | | | | | | | | | | | | |
| a. Depreciation [d] | | $461,903 | $461,903 | $461,903 | $461,990 | $462,077 | $462,077 | $462,077 | $462,077 | $462,077 | $462,077 | $462,077 | $462,526 | $5,544,769 |
| 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. Other | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9. Total System Recoverable Expenses (Lines 7 & 8) | | $2,037,038 | $2,033,444 | $2,029,850 | $2,027,637 | $2,025,741 | $2,022,462 | $2,018,867 | $2,015,271 | $2,011,676 | $2,008,080 | $2,004,484 | $2,001,336 | $24,235,887 |

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.4904% based on May 2015 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

[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 of 6.36% based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.89% based on the May 2015 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

JANUARY 2016 THROUGH DECEMBER 2016

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | ($18,368) | ($17,255) | ($16,142) | ($15,029) | ($13,916) | ($12,803) | ($11,690) | ($10,577) | ($9,464) | ($8,351) | ($7,238) | ($6,125) | ($5,012) | |
| 2. Total Working Capital | ($18,368) | ($17,255) | ($16,142) | ($15,029) | ($13,916) | ($12,803) | ($11,690) | ($10,577) | ($9,464) | ($8,351) | ($7,238) | ($6,125) | ($5,012) | |
| 3. Average Net Working Capital Balance | | ($17,811) | ($16,698) | ($15,585) | ($14,472) | ($13,359) | ($12,246) | ($11,133) | ($10,020) | ($8,907) | ($7,794) | ($6,681) | ($5,568) | |
| 4. Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| a. Equity Component grossed up for taxes [a] | | ($116) | ($109) | ($102) | ($95) | ($87) | ($80) | ($73) | ($66) | ($58) | ($51) | ($44) | ($36) | |
| b. Debt Component [b] | | ($22) | ($21) | ($19) | ($18) | ($17) | ($15) | ($14) | ($12) | ($11) | ($10) | ($8) | ($7) | |
| 5. Total Return Component [e] | | ($139) | ($130) | ($121) | ($113) | ($104) | ($95) | ($87) | ($78) | ($69) | ($61) | ($52) | ($43) | ($1,092) |
| 6. Expense Dr(Cr) | | | | | | | | | | | | | | |
| a. 411.800 Gains from Dispositions of Allowances | | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | |
| b. 411.900 Losses from Dispositions of Allowances | | $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 | |
| 7. Net Expense (Lines 6a + 6b + 6c) [f] | | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($1,113) | ($13,356) |
| 8. Total System Recoverable Expenses (Lines 5 + 7) | | ($1,252) | ($1,243) | ($1,234) | ($1,226) | ($1,217) | ($1,208) | ($1,200) | ($1,191) | ($1,182) | ($1,174) | ($1,165) | ($1,156) | |
| a. Recoverable Costs Allocated to Energy | | ($1,252) | ($1,243) | ($1,234) | ($1,226) | ($1,217) | ($1,208) | ($1,200) | ($1,191) | ($1,182) | ($1,174) | ($1,165) | ($1,156) | |
| b. Recoverable Costs Allocated to Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 9. Energy Jurisdictional Factor | | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | 94.88715% | |
| 10. Demand Jurisdictional Factor | | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | 94.67506% | |
| 11. Retail Energy-Related Recoverable Costs [c] | | ($1,188) | ($1,179) | ($1,171) | ($1,163) | ($1,155) | ($1,146) | ($1,138) | ($1,130) | ($1,122) | ($1,114) | ($1,105) | ($1,097) | |
| 12. Retail Demand-Related Recoverable Costs [d] | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 13. Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | ($1,188) | ($1,179) | ($1,171) | ($1,163) | ($1,155) | ($1,146) | ($1,138) | ($1,130) | ($1,122) | ($1,114) | ($1,105) | ($1,097) | ($13,709) |

[a] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8201% is based on May 2015 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[b] The Debt Component is 1.4904% based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

[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

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

Florida Power Light Company
Environmental Cost Recovery Clause
2016 Annual Capital Depreciation Schedule

FORM: 42-4P

| Project | | Class ID | Plant | Unit | Utility | Depreciation Rate / Amortization Period | Estimated Balance Dec-15 | Estimated Balance Dec-16 |
|---|---|---|---|---|---|---|---|---|
| 002-LOW NOX BURNER TECHNOLOGY | | 02 - Steam Generation Plant | Turkey Pt | Turkey Pt U1 | 31200 | 2.50% | 2,563,376 | 2,563,376 |
| **002-LOW NOX BURNER TECHNOLOGY** | **Total** | | | | | | **2,563,376** | **2,563,376** |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Manatee | Manatee Comm | 31200 | 2.60% | 65,605 | 186,181 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Manatee | Manatee U1 | 31100 | 2.10% | 56,430 | 56,430 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Manatee | Manatee U1 | 31200 | 2.60% | 640,630 | 640,630 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Manatee | Manatee U2 | 31100 | 2.10% | 56,333 | 56,333 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Manatee | Manatee U2 | 31200 | 2.60% | 740,318 | 740,318 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Martin | Martin Comm | 31200 | 2.60% | 31,632 | 31,632 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Martin | Martin Comm | 31650 | 20.00% | 58,207 | 58,207 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Martin | Martin Comm | 31670 | 14.29% | 66,897 | 66,897 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Martin | Martin U1 | 31100 | 2.10% | 36,811 | 36,811 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Martin | Martin U1 | 31200 | 2.60% | 533,645 | 533,645 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Martin | Martin U2 | 31100 | 2.10% | 36,845 | 36,845 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Martin | Martin U2 | 31200 | 2.60% | 529,520 | 529,520 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Scherer | Scherer U4 | 31200 | 2.60% | 515,653 | 515,653 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP - Comm | 31100 | 2.10% | 43,193 | 43,193 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP U1 | 31200 | 2.60% | 780 | 780 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP U2 | 31200 | 2.60% | 780 | 780 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Turkey Pt | Turkey Pt Comm | 31100 | 2.10% | 59,056 | 59,056 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Turkey Pt | Turkey Pt Comm | 31200 | 2.50% | 29,142 | 29,142 |
| 003-CONTINUOUS EMISSION MONITORING | | 02 - Steam Generation Plant | Turkey Pt | Turkey Pt U1 | 31200 | 2.50% | 382,004 | 382,004 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale Comm | 34100 | 3.50% | 58,860 | 58,860 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale Comm | 34500 | 3.40% | 34,502 | 34,502 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale GTs | 34300 | 2.90% | 10,225 | 10,225 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale U4 | 34300 | 4.30% | 487,395 | 487,395 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale U5 | 34300 | 4.20% | 498,340 | 498,340 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Ft Myers | FtMyers U2 | 34300 | 4.20% | 165,032 | 165,032 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Ft Myers | FtMyers U3 | 34300 | 5.20% | 2,283 | 2,283 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Manatee | Manatee U3 | 34300 | 4.30% | 87,691 | 87,691 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Martin | Martin U3 | 34300 | 4.20% | 421,385 | 421,385 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Martin | Martin U4 | 34300 | 4.20% | 413,986 | 413,986 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Martin | Martin U8 | 34300 | 4.30% | 13,693 | 13,693 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Sanford | Sanford U4 | 34300 | 4.80% | 171,843 | 171,843 |
| 003-CONTINUOUS EMISSION MONITORING | | 05 - Other Generation Plant | Sanford | Sanford U5 | 34300 | 4.20% | 134,809 | 134,809 |
| **003-CONTINUOUS EMISSION MONITORING** | **Total** | | | | | | **6,383,526** | **6,504,102** |
| 004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION | | 02 - Steam Generation Plant | Turkey Pt | Turkey Pt Comm | 31100 | 2.10% | 21,799 | 21,799 |
| **004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION** | **Total** | | | | | | **21,799** | **21,799** |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 02 - Steam Generation Plant | Manatee | Manatee Comm | 31100 | 2.10% | 3,111,263 | 3,111,263 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 02 - Steam Generation Plant | Manatee | Manatee Comm | 31200 | 2.60% | 174,543 | 174,543 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 02 - Steam Generation Plant | Manatee | Manatee U1 | 31200 | 2.60% | 104,845 | 104,845 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 02 - Steam Generation Plant | Manatee | Manatee U2 | 31200 | 2.60% | 127,429 | 127,429 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 02 - Steam Generation Plant | Martin | Martin Comm | 31100 | 2.10% | 1,110,450 | 1,110,450 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 02 - Steam Generation Plant | Martin | Martin Comm | 31200 | 2.60% | 94,329 | 94,329 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 02 - Steam Generation Plant | Martin | Martin U1 | 31100 | 2.10% | 261,417 | 261,417 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 02 - Steam Generation Plant | Martin | Martin U2 | 31100 | 2.10% | 85,078 | 85,078 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP - Comm | 31100 | 2.10% | 42,091 | 42,091 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP - Comm | 31200 | 2.60% | 2,292 | 2,292 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 02 - Steam Generation Plant | Turkey Pt | Turkey Pt Comm | 31100 | 2.10% | 87,560 | 87,560 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale Comm | 34200 | 3.80% | 898,111 | 898,111 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale GTs | 34200 | 2.60% | 584,290 | 584,290 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 05 - Other Generation Plant | Ft Myers | FtMyers GTs | 34200 | 2.70% | 133,479 | 133,479 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 05 - Other Generation Plant | Ft Myers | FtMyers U3 | 34200 | 3.80% | 18,616 | 18,616 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 05 - Other Generation Plant | Martin | Martin Comm | 34200 | 3.80% | 455,336 | 455,336 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 05 - Other Generation Plant | Pt Everglades | PtEverglades GTs | 34200 | 2.60% | 2,768,744 | 2,768,744 |
| 005-MAINTENANCE OF ABOVE GROUND FUEL TANKS | | 08 - General Plant | General Plant | General Plant | 39000 | 2.10% | 5,837,840 | 5,837,840 |
| **005-MAINTENANCE OF ABOVE GROUND FUEL TANKS** | **Total** | | | | | | **15,897,715** | **15,897,715** |
| 007-RELOCATE TURBINE LUBE OIL PIPING | | 03 - Nuclear Generation Plant | St Lucie | StLucie U1 | 32300 | 2.40% | 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 | 2.10% | 46,882 | 46,882 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Manatee | Manatee Comm | 31670 | 14.29% | 54,241 | 54,241 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Martin | Martin Comm | 31600 | 2.40% | 23,107 | 23,107 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Martin | Martin Comm | 31650 | 20.00% | 56,000 | 121,312 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Martin | Martin Comm | 31670 | 14.29% | 263,330 | 263,330 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Turkey Pt | Turkey Pt Comm | 31100 | 2.10% | 5,895 | 5,895 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 02 - Steam Generation Plant | Turkey Pt | Turkey Pt Comm | 31670 | 14.29% | 2,576 | 2,576 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale Comm | 34100 | 3.50% | 363,996 | 514,716 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 05 - Other Generation Plant | Ft Myers | FtMyers Comm | 34650 | 20.00% | 9,728 | - |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 05 - Other Generation Plant | Sanford | Sanford Comm | 34100 | 3.50% | 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 | 2.10% | 4,413 | 4,413 |
| 008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT | 08 - General Plant | General Plant | General Plant | 39190 | 33.33% | 8,552 | 6,398 |
| **008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total** | | | | | | **857,637** | **1,061,787** |
| 010-REROUTE STORMWATER RUNOFF | 03 - Nuclear Generation Plant | St Lucie | StLucie Comm | 32100 | 1.80% | 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 | 2.10% | 524,873 | 524,873 |
| 012-SCHERER DISCHARGE PIPELINE | 02 - Steam Generation Plant | Scherer | Scherer Comm | 31200 | 2.60% | 328,762 | 328,762 |
| 012-SCHERER DISCHARGE PIPELINE | 02 - Steam Generation Plant | Scherer | Scherer Comm | 31400 | 2.59% | 689 | 689 |
| **012-SCHERER DISCHARGE PIPELINE Total** | | | | | | **854,324** | **854,324** |
| 020-WASTEWATER/STORMWATER DISCH ELIMINATION | 02 - Steam Generation Plant | Martin | Martin U1 | 31200 | 2.60% | 367,906 | 367,906 |
| 020-WASTEWATER/STORMWATER DISCH ELIMINATION | 02 - Steam Generation Plant | Martin | Martin U2 | 31200 | 2.60% | 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 | 1.80% | 6,078,732 | 6,078,732 |
| **021-ST.LUCIE TURTLE NETS Total** | | | | | | **6,078,732** | **6,078,732** |
| 022-PIPELINE INTEGRITY MANAGEMENT | 02 - Steam Generation Plant | Manatee | Manatee Comm | 31100 | 2.10% | 601,217 | 601,217 |
| 022-PIPELINE INTEGRITY MANAGEMENT | 02 - Steam Generation Plant | Martin | Martin Comm | 31100 | 2.10% | 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 | 2.10% | 816,259 | 816,259 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Manatee | Manatee Comm | 31200 | 2.60% | 33,272 | 33,272 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Manatee | Manatee Comm | 31500 | 2.40% | 26,325 | 26,325 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Manatee | Manatee U1 | 31200 | 2.60% | 45,750 | 45,750 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Manatee | Manatee U2 | 31200 | 2.60% | 37,431 | 37,431 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Martin | Martin Comm | 31100 | 2.10% | 343,785 | 343,785 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Martin | Martin Comm | 31500 | 2.40% | 34,755 | 34,755 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 02 - Steam Generation Plant | Turkey Pt | Turkey Pt Comm | 31100 | 2.10% | 92,013 | 3,015,674 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 03 - Nuclear Generation Plant | St Lucie | StLucie U1 | 32300 | 2.40% | 712,225 | 712,225 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 03 - Nuclear Generation Plant | St Lucie | StLucie U1 | 32400 | 1.80% | 745,335 | 745,335 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 03 - Nuclear Generation Plant | St Lucie | StLucie U2 | 32300 | 2.40% | 552,390 | 552,390 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale Comm | 34100 | 3.50% | 189,219 | 189,219 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale Comm | 34200 | 3.80% | 1,480,169 | 1,480,169 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale Comm | 34300 | 6.00% | 28,250 | 28,250 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale GTs | 34100 | 2.20% | 92,727 | 92,727 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale GTs | 34200 | 2.60% | 513,250 | 513,250 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Ft Myers | FtMyers GTs | 34100 | 2.30% | 98,715 | 98,715 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Ft Myers | FtMyers GTs | 34200 | 2.70% | 629,983 | 629,983 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Ft Myers | FtMyers GTs | 34500 | 2.20% | 12,430 | 12,430 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Ft Myers | FtMyers U2 | 34300 | 4.20% | 49,727 | 49,727 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Ft Myers | FtMyers U3 | 34500 | 3.40% | 12,430 | 12,430 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Martin | Martin Comm | 34100 | 3.50% | 523,498 | 523,498 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Martin | Martin U8 | 34200 | 3.80% | 84,868 | 84,868 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Pt Everglades | PtEverglades Comm | 34200 | 3.30% | 1,607,728 | 1,607,728 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Pt Everglades | PtEverglades GTs | 34100 | 2.20% | 454,081 | 454,081 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Pt Everglades | PtEverglades GTs | 34200 | 2.60% | 1,835,190 | 1,835,190 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Pt Everglades | PtEverglades GTs | 34500 | 2.10% | 7,783 | 7,783 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 05 - Other Generation Plant | Sanford | Sanford Comm | 34100 | 3.50% | 288,383 | 288,383 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 06 - Transmission Plant - Electric | Distribution | Mass Distribution Plant | 36100 | 1.90% | - | - |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 06 - Transmission Plant - Electric | Radial | Radial | 35200 | 1.90% | 6,946 | 6,946 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35200 | 1.90% | 1,164,630 | 1,244,630 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35300 | 2.60% | 177,982 | 177,982 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35800 | 1.80% | 65,655 | 65,655 |
| 023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36100 | 1.90% | 3,143,351 | 3,143,351 |
| 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 | 2.10% | 146,691 | 146,691 |
| **023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES Total** | | | | | | **16,123,727** | **19,127,388** |
| 024-GAS REBURN | 02 - Steam Generation Plant | Manatee | Manatee U1 | 31200 | 2.60% | 16,687,312 | 16,853,104 |
| 024-GAS REBURN | 02 - Steam Generation Plant | Manatee | Manatee U2 | 31200 | 2.60% | 15,506,591 | 15,507,494 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **024-GAS REBURN Total** | | | | | | | **32,193,902** | **32,360,598** |
| 026-UST REPLACEMENT/REMOVAL | 08 - General Plant | General Plant | General Plant | 39000 | 2.10% | | 115,447 | 115,447 |
| **026-UST REPLACEMENT/REMOVAL Total** | | | | | | | **115,447** | **115,447** |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Manatee | Manatee Comm | 31100 | 2.10% | | 102,052 | 102,052 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Manatee | Manatee U1 | 31200 | 2.60% | | 20,059,060 | 20,059,060 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Manatee | Manatee U1 | 31400 | 2.60% | | 7,240,711 | 7,240,711 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Manatee | Manatee U2 | 31200 | 2.60% | | 20,461,529 | 20,461,529 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Manatee | Manatee U2 | 31400 | 2.60% | | 7,905,907 | 7,905,907 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin | Martin Comm | 31200 | 2.60% | | 518,275 | 518,275 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin | Martin Comm | 31400 | 2.60% | | 287,258 | 287,258 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin | Martin U1 | 31200 | 2.60% | | 19,504,077 | 19,504,077 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin | Martin U1 | 31400 | 2.60% | | 7,499,710 | 7,499,710 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin | Martin U2 | 31200 | 2.60% | | 20,248,975 | 20,248,975 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Martin | Martin U2 | 31400 | 2.60% | | 7,477,120 | 7,477,120 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer | Scherer U4 | 31100 | 2.10% | | 82,935,636 | 82,935,636 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer | Scherer U4 | 31200 | 2.60% | | 253,051,547 | 255,154,593 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer | Scherer U4 | 31400 | 2.60% | | 477,256 | 477,256 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer | Scherer U4 | 31500 | 2.40% | | 19,219,358 | 19,219,358 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer | Scherer U4 | 31600 | 2.40% | | 2,190,752 | 2,190,752 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | Scherer | Scherer U4 | 31670 | 14.29% | | 12,507 | 12,507 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP U1 | 31200 | 2.60% | | 27,750,108 | 27,750,108 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP U1 | 31500 | 2.40% | | 446,734 | 446,734 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP U1 | 31600 | 2.40% | | 9,138 | 9,138 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP U2 | 31200 | 2.60% | | 26,540,984 | 26,540,984 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP U2 | 31500 | 2.40% | | 426,220 | 426,220 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP U2 | 31600 | 2.40% | | 9,591 | 9,591 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | Ft Lauderdale | FtLauderdale GTs | 34300 | 2.90% | | 110,242 | 110,242 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | Ft Myers | FtMyers GTs | 34300 | 3.10% | | 57,855 | 57,855 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | Martin | Martin Comm | 34100 | 3.50% | | 763,350 | 763,350 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | Martin | Martin Comm | 34300 | 4.30% | | 244,343 | 244,343 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | Martin | Martin Comm | 34500 | 3.40% | | 292,499 | 292,499 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 05 - Other Generation Plant | Pt Everglades | PtEverglades GTs | 34300 | 3.40% | | 107,874 | 107,874 |
| 031-CLEAN AIR INTERSTATE RULE-CAIR | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36500 | 3.90% | | 411,775 | 411,775 |
| **031-CLEAN AIR INTERSTATE RULE-CAIR Total** | | | | | | | **526,362,444** | **528,465,490** |
| 033-CLEAN AIR MERCURY RULE-MATS | 02 - Steam Generation Plant | Scherer | Scherer U4 | 31100 | 2.10% | | 225,068 | 225,068 |
| 033-CLEAN AIR MERCURY RULE-MATS | 02 - Steam Generation Plant | Scherer | Scherer U4 | 31200 | 2.60% | | 106,958,839 | 111,374,106 |
| 033-CLEAN AIR MERCURY RULE-MATS | 02 - Steam Generation Plant | St Johns River Power Plant | SJRPP U1 | 31200 | 2.60% | | 36,805 | 36,805 |
| **033-CLEAN AIR MERCURY RULE-MATS** | | | | | | | **107,220,712** | **111,635,979** |
| 034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE | 03 - Nuclear Generation Plant | St Lucie | StLucie Comm | 32100 | 1.80% | | - | - |
| **034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE Total** | | | | | | | - | - |
| 035-MARTIN PLANT DRINKING WATER COMP | 02 - Steam Generation Plant | Martin | Martin Comm | 31100 | 2.10% | | 235,391 | 235,391 |
| **035-MARTIN PLANT DRINKING WATER COMP Total** | | | | | | | **235,391** | **235,391** |
| 036-LOW LEV RADI WSTE-LLW | 03 - Nuclear Generation Plant | St Lucie | StLucie Comm | 32100 | 1.80% | | 7,601,405 | 7,601,405 |
| 036-LOW LEV RADI WSTE-LLW | 03 - Nuclear Generation Plant | Turkey Pt | Turkey Pt Comm | 32100 | 1.80% | | 9,806,188 | 9,806,188 |
| **036-LOW LEV RADI WSTE-LLW Total** | | | | | | | **17,407,593** | **17,407,593** |
| 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 | 3.30% | | 4,502,770 | 4,502,770 |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto | Desoto Solar | 34300 | 3.30% | | 115,297,908 | 115,297,908 |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto | Desoto Solar | 34500 | 3.30% | | 26,746,266 | 26,746,266 |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto | Desoto Solar | 34600 | 3.30% | | 649,885 | 654,909 |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto | Desoto Solar | 34630 | 33.33% | | 20,537 | - |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto | Desoto Solar | 34650 | 20.00% | | 25,133 | 25,133 |
| 037-DE SOTO SOLAR PROJECT | 05 - Other Generation Plant | Desoto | Desoto Solar | 34670 | 14.29% | | 101,556 | 93,231 |
| 037-DE SOTO SOLAR PROJECT | 06 - Transmission Plant - Electric | Trans_Generator_Leads | TransGeneratorLead | 35300 | 2.60% | | 313,491 | 313,491 |
| 037-DE SOTO SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35200 | 1.90% | | 7,427 | 7,427 |
| 037-DE SOTO SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35300 | 2.60% | | 920,949 | 920,949 |
| 037-DE SOTO SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35310 | 2.90% | | 1,697,968 | 1,697,968 |
| 037-DE SOTO SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35500 | 3.40% | | 394,418 | 394,418 |
| 037-DE SOTO SOLAR PROJECT | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35600 | 3.20% | | 191,358 | 191,358 |
| 037-DE SOTO SOLAR PROJECT | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36100 | 1.90% | | 540,994 | 540,994 |
| 037-DE SOTO SOLAR PROJECT | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36200 | 2.60% | | 1,938,179 | 1,938,179 |
| 037-DE SOTO SOLAR PROJECT | 08 - General Plant | General Plant | General Plant | 39220 | 9.40% | | 28,426 | 28,426 |
| 037-DE SOTO SOLAR PROJECT | 08 - General Plant | General Plant | General Plant | 39720 | 14.29% | | 21,238 | 21,238 |
| **037-DE SOTO SOLAR PROJECT Total** | | | | | | | **153,654,009** | **153,630,171** |
| 038-SPACE COAST SOLAR PROJECT | 01 - Intangible Plant | Intangible Plant | Intangible Plant | 30300 | 0.00% | | 6,359,027 | 6,359,027 |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast | Space Coast Solar | 34100 | 3.30% | | 3,838,726 | 3,838,726 |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast | Space Coast Solar | 34300 | 3.30% | | 51,606,083 | 51,606,083 |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast | Space Coast Solar | 34500 | 3.30% | | 6,126,699 | 6,126,699 |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast | Space Coast Solar | 34600 | 3.30% | | 16,683 | 16,683 |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast | Space Coast Solar | 34630 | 33.33% | | 1,310 | - |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast | Space Coast Solar | 34650 | 20.00% | | 23,642 | 23,642 |
| 038-SPACE COAST SOLAR PROJECT | 05 - Other Generation Plant | Space Coast | Space Coast Solar | 34670 | 14.29% | | 51,560 | 51,560 |

Florida Power Light Company
Environmental Cost Recovery Clause
2016 Annual Capital Depreciation Schedule

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| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 038-SPACE COAST SOLAR PROJECT | | 06 - Transmission Plant - Electric | Trans_Generator_Leads | TransGeneratorLead | 35300 | 2.60% | 789,138 | 789,138 |
| 038-SPACE COAST SOLAR PROJECT | | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35300 | 2.60% | 139,391 | 139,391 |
| 038-SPACE COAST SOLAR PROJECT | | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35310 | 2.90% | 1,328,699 | 1,328,699 |
| 038-SPACE COAST SOLAR PROJECT | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36100 | 1.90% | 274,858 | 274,858 |
| 038-SPACE COAST SOLAR PROJECT | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36200 | 2.60% | 62,689 | 64,063 |
| 038-SPACE COAST SOLAR PROJECT | | 08 - General Plant | General Plant | General Plant | 39220 | 9.40% | 31,858 | 31,858 |
| 038-SPACE COAST SOLAR PROJECT | | 08 - General Plant | General Plant | General Plant | 39720 | 14.29% | 6,741 | 6,741 |
| **038-SPACE COAST SOLAR PROJECT** | **Total** | | | | | | **70,657,104** | **70,657,169** |
| 039-MARTIN SOLAR PROJECT | | 05 - Other Generation Plant | Martin | Martin U8 | 34300 | 4.30% | 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 | 3.30% | 20,746,646 | 20,746,646 |
| 039-MARTIN SOLAR PROJECT | | 05 - Other Generation Plant | Martin Solar | Martin Solar | 34300 | 3.30% | 395,164,560 | 396,431,628 |
| 039-MARTIN SOLAR PROJECT | | 05 - Other Generation Plant | Martin Solar | Martin Solar | 34500 | 3.30% | 4,125,204 | 4,125,204 |
| 039-MARTIN SOLAR PROJECT | | 05 - Other Generation Plant | Martin Solar | Martin Solar | 34600 | 3.30% | 1,299 | 1,299 |
| 039-MARTIN SOLAR PROJECT | | 05 - Other Generation Plant | Martin Solar | Martin Solar | 34650 | 20.00% | 11,178 | 11,178 |
| 039-MARTIN SOLAR PROJECT | | 05 - Other Generation Plant | Martin Solar | Martin Solar | 34670 | 14.29% | 11,896 | 11,896 |
| 039-MARTIN SOLAR PROJECT | | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35500 | 3.40% | 603,692 | 603,692 |
| 039-MARTIN SOLAR PROJECT | | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35600 | 3.20% | 364,159 | 364,159 |
| 039-MARTIN SOLAR PROJECT | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36400 | 4.10% | 9,282 | 9,282 |
| 039-MARTIN SOLAR PROJECT | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36660 | 1.50% | 94,476 | 94,476 |
| 039-MARTIN SOLAR PROJECT | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36760 | 2.60% | 2,728 | 2,728 |
| 039-MARTIN SOLAR PROJECT | | 08 - General Plant | General Plant | General Plant | 39220 | 9.40% | 25,193 | 25,193 |
| 039-MARTIN SOLAR PROJECT | | 08 - General Plant | General Plant | General Plant | 39240 | 11.10% | 399,176 | 399,176 |
| 039-MARTIN SOLAR PROJECT | | 08 - General Plant | General Plant | General Plant | 39290 | 3.50% | 114,262 | 114,262 |
| 039-MARTIN SOLAR PROJECT | | 08 - General Plant | General Plant | General Plant | 39420 | 14.29% | 18,993 | 18,993 |
| 039-MARTIN SOLAR PROJECT | | 08 - General Plant | General Plant | General Plant | 39720 | 14.29% | 3,204 | 3,204 |
| **039-MARTIN SOLAR PROJECT** | **Total** | | | | | | **422,335,919** | **423,602,987** |
| 041-MANATEE HEATING SYSTEM | | 02 - Steam Generation Plant | Pt Everglades | PtEverglades Comm | 31400 | CRS | 1,478,577 | 1,478,577 |
| 041-MANATEE HEATING SYSTEM | | 05 - Other Generation Plant | Cape Canaveral | CapeCanaveral Comm | 34300 | CRS | 4,042,459 | 4,042,459 |
| 041-MANATEE HEATING SYSTEM | | 06 - Transmission Plant - Electric | Transmission | Transmission Plant - Electric | 35300 | 2.60% | 276,404 | 276,404 |
| 041-MANATEE HEATING SYSTEM | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36100 | 1.90% | 73,267 | 73,267 |
| 041-MANATEE HEATING SYSTEM | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36200 | 2.60% | 472,661 | 472,661 |
| 041-MANATEE HEATING SYSTEM | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36400 | 4.10% | 225,952 | 225,952 |
| 041-MANATEE HEATING SYSTEM | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36500 | 3.90% | 307,599 | 307,599 |
| 041-MANATEE HEATING SYSTEM | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36660 | 1.50% | 221,326 | 221,326 |
| 041-MANATEE HEATING SYSTEM | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36760 | 2.60% | 168,995 | 168,995 |
| 041-MANATEE HEATING SYSTEM | | 07 - Distribution Plant - Electric | Distribution | Mass Distribution Plant | 36910 | CRS | 607 | 607 |
| 041-MANATEE HEATING SYSTEM | | 08 - General Plant | General Plant | General Plant | 39720 | 14.29% | 16,244 | 16,244 |
| **041-MANATEE HEATING SYSTEM** | **Total** | | | | | | **7,284,092** | **7,284,092** |
| 042-PTN COOLING CANAL MONITORING SYS | | 03 - Nuclear Generation Plant | Turkey Pt | Turkey Pt Comm | 32100 | 1.80% | 8,941,833 | 16,285,641 |
| **042-PTN COOLING CANAL MONITORING SYS** | **Total** | | | | | | **8,941,833** | **16,285,641** |
| 044-Barley Barber Swamp Iron Mitiga | | 02 - Steam Generation Plant | Martin | Martin Comm | 31100 | 2.10% | 164,719 | 164,719 |
| **044-Barley Barber Swamp Iron Mitiga** | **Total** | | | | | | **164,719** | **164,719** |
| 045-800 MW UNIT ESP PROJECT | | 02 - Steam Generation Plant | Manatee | Manatee Comm | 31200 | 2.60% | - | 494,729 |
| 045-800 MW UNIT ESP PROJECT | | 02 - Steam Generation Plant | Manatee | Manatee U1 | 31200 | 2.60% | 44,988,527 | 44,988,527 |
| 045-800 MW UNIT ESP PROJECT | | 02 - Steam Generation Plant | Manatee | Manatee U1 | 31500 | 2.40% | 4,409,692 | 4,409,692 |
| 045-800 MW UNIT ESP PROJECT | | 02 - Steam Generation Plant | Manatee | Manatee U1 | 31600 | 2.40% | 1,021,918 | 1,021,918 |
| 045-800 MW UNIT ESP PROJECT | | 02 - Steam Generation Plant | Manatee | Manatee U2 | 31200 | 2.60% | 51,927,967 | 51,927,967 |
| 045-800 MW UNIT ESP PROJECT | | 02 - Steam Generation Plant | Manatee | Manatee U2 | 31500 | 2.40% | 4,661,952 | 4,661,952 |
| 045-800 MW UNIT ESP PROJECT | | 02 - Steam Generation Plant | Manatee | Manatee U2 | 31600 | 2.40% | 1,051,553 | 1,051,553 |
| 045-800 MW UNIT ESP PROJECT | | 02 - Steam Generation Plant | Martin | Martin U1 | 31200 | 2.60% | 47,146,158 | 47,146,158 |
| 045-800 MW UNIT ESP PROJECT | | 02 - Steam Generation Plant | Martin | Martin U1 | 31500 | 2.40% | 4,322,420 | 4,322,420 |
| 045-800 MW UNIT ESP PROJECT | | 02 - Steam Generation Plant | Martin | Martin U1 | 31600 | 2.40% | 1,002,877 | 1,002,877 |
| 045-800 MW UNIT ESP PROJECT | | 02 - Steam Generation Plant | Martin | Martin U2 | 31200 | 2.60% | 53,920,018 | 53,920,018 |
| **045-800 MW UNIT ESP PROJECT** | **Total** | | | | | | **214,453,082** | **214,947,811** |
| 54-COAL COMBUSTION RESIDUALS | | 02 - Steam Generation Plant | Scherer | Scherer U4 | 31100 | 2.10% | - | - |
| 54-COAL COMBUSTION RESIDUALS | | 02 - Steam Generation Plant | Scherer | Scherer U4 | 31200 | 2.60% | - | - |
| **54-COAL COMBUSTION RESIDUALS** | **Total** | | | | | | **-** | **-** |
| **Grand Total** | | | | | | | **1,613,600,273** | **1,632,695,500** |

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Air Operating Permit Fees - O&M**

**Project No. 1**

**Project Description:**

The Clean Air Act Amendments of 1990, Public Law 101-549, and Florida Statutes 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. It is calculated by multiplying the applicable annual operation license fee factor by the tons of each air pollutant emitted by the unit during the previous year and regulated in each unit's air operating permit, up to a total of 4,000 tons per pollutant. The major regulated pollutants at the present time are sulfur dioxide (SO2), nitrogen oxides (NOx) and particulate matter. The fee covers FPL's units within the state of Florida, as well as Unit 4 of Plant Scherer located in Juliette, Georgia in which FPL owns a 76.36% share. The fees for FPL's units in Florida are paid to the Florida Department of Environmental Protection (FDEP) generally in February of each year, whereas FPL pays its share of the fees for Scherer Unit 4 to Georgia Power Company on a monthly basis.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Year 2014 air operating permit fees for the Florida facilities were calculated in the first quarter of 2015 utilizing 2014 air operating information. They were paid to the FDEP in March 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $284,412 or 101.3% higher than previously projected. Actual fuel consumption, and associated emissions, for both gas and oil for 2014 (used for 2015 projections) was significantly higher than original projections, which is the primary driver for the cost variance. Additionally, state required emissions fees for each ton emitted increased slightly.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $273,565.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Continuous Emission Monitoring Systems (CEMS) - O&M**

**Project No. 3a**

**Project Description:**

The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping, and reporting of SO2, NOx, Carbon Dioxide (CO2) 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.

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 and opacity. These systems continuously monitor and quantify emissions (as required) for each power plant stack and have automated data acquisition and reporting capability. Operation and maintenance of these systems in accordance with the provisions of 40 CFR Part 75 is an ongoing activity, which follow the CEMS Quality Assurance Program Manual.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Operation and maintenance of the CEMS continue to be performed according to requirements of the CEMS Quality Assurance (QA) Program Manual, 40 CFR Parts 60 & 75 regulations and all applicable state regulations, as well as local requirements. Relative Accuracy Tests and Linearity Tests continue to be performed as scheduled for quality assurance and as needed for diagnostic or recertification requirements. QA/QC 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 has been replaced as recommended by OEMs. CEMS analyzer calibration gases are purchased as needed to meet required daily and QA calibrations. 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 Babcock & Wilcox / KVB-Enertec (CEMS NETDAHS) 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 or changes made by the EPA, State and Local Agencies. Training on the operation and maintenance of the system, as well as rule/regulation changes continue as needed.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures are estimated to be $37,541 or 5.4% higher than previously projected. The variance is primarily due to the replacement of the Ft. Myers CEMS umbilicals on the combined cycle and bypass stacks. This was partially offset by lower than expected costs for oil sample analyses at the Martin and Manatee 800 MW units that resulted from lower than projected oil use.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $591,966.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks - O&M**

**Project No. 5a**

**Project Description:**

Florida Administrative Code (F.A.C.) Chapter 62-761, previously 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Work continued on miscellaneous maintenance of above ground fuel storage tanks and piping systems. All required API 653 external inspections will be completed for this year and all 2015 tank registration fees have been paid. In 2015 we performed two API internal inspection (TPE tanks 901 & 902), scheduled one (PMR Unit 2 Metering Tank for September, and executed four API external (in-service) inspections on PFM Tanks 1 & 2, PTF 5 L/O Tank & PMT Unit 1 Metering Tank which were due for external inspection. Additionally, external coating system replacement/ repair was performed on PFM Tanks 1 & 2, PMT Tanks 1371/A &B, PMT Units 1 &2 Metering & L/O start up tanks, and TPE tank 902. The Manatee Terminal Tanks 1271/A&B painting is scheduled for August, 2015 and will be completed by November, 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $71,024 or 3.2% higher than previously projected. The variance is primarily due to the API internal inspection of the Martin Unit 2 metering tank, which was not originally budgeted. FPL is implementing the use of a new work management system to improve the budgeting process in order to avoid reoccurrences of similar issues. In addition, work performed in 2014 at the Manatee Terminal was inadvertently charged to the SPCC project. A correcting entry was made in February of 2015.

Project increases were partially offset by lower than projected costs resulting from competitive bidding associated with the painting of the tanks at Ft. Myers Units 1 and 2. The increase was also partially offset by lower than projected costs associated with the API internal inspection of Tank 902 at the Port Everglades plant. Costs associated with tank cleaning were included as part of lease termination activities and therefore were not incurred as part of inspection costs.

**Project Projections**:

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $213,583.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: RCRA Corrective Action - O&M**

**Project No. 13**

**Project Description:**

Under the Hazardous and Solid Waste Amendments of 1984 (amending the Resource Conservation and Recovery Act, or RCRA), the U.S. EPA has the authority to require hazardous waste treatment facilities to investigate whether there have been releases of hazardous waste or constituents from non-regulated units on the facility site. If contamination is found to be present at levels that represent a threat to human health or the environment, the facility operator would be required to undertake "corrective action" to remediate the contamination. In April 1994, the U.S. EPA advised FPL that it intended to initiate RCRA Facility Assessments (RFAs) at FPL's nine former hazardous waste treatment facility sites. The RFA is the first step in the RCRA Corrective Action process. At a minimum, FPL will be responding to the agency's requests for information concerning the operation of these power plants, their waste streams, their former hazardous waste treatment facilities, and their non-regulated Solid Waste Management Units (SWMUs). FPL may also conduct assessments of human health risks resulting from possible releases from the SWMU's in order to demonstrate that any residual contamination does not represent an undue threat to human health or the environment. Other response actions could include a voluntary clean-up or compliance with the agency's imposition of the full gamut of RCRA Corrective Action requirements, including RCRA Facility Investigation, Corrective Measures Study, and Corrective Measures Implementation.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

The FDEP issued a letter to FPL on June 20, 2013, allowing the closure of the turbine lube oil and transformer spill sites as well as the diesel fuel spill sites at St. Lucie. The deed restrictions for the Turbine Lube Oil and Transformer spill sites have been approved and recorded with the State of Florida. FPL is now waiting on the site rehabilitation completion order (SRCO) to be prepared by the FDEP. The SRCO is expected by the end of 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

No expenditures have been incurred in 2015.

**Project Projection:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $0.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: NPDES Permit Fees – O&M**

**Project No. 14**

**Project Description:**

In compliance with State of Florida Rule 62-4.052, FPL is required to pay annual regulatory program and surveillance fees for any permits it requires to discharge wastewater to surface waters under the National Pollution Discharge Elimination System (NPDES). These fees implement the Florida legislature's intent that the Florida Department of Environmental Protection's (FDEP) costs for administering the NPDES program be borne by the regulated parties, as applicable. The fees for each permit type are as set forth in the rule, with an effective date of May 1, 1995, for their implementation.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

The NPDES permit fees were paid to FDEP for power generation operating plants and nuclear plants. The payment is due in January of each year, and the payment for 2015 was done on time.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures are estimated to be on target.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $69,200.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Disposal of Noncontainerized Liquid Waste - O&M**

**Project 17a**

**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, 2015 to December 31, 2015)

Required routine maintenance has been performed in 2015, and only minimal work is planned for the remainder of the year due to low oil burning.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $62,369 or 96.0% lower than previously projected. The variance is primarily due to lower than projected processing of ash at the Martin site, resulting from reduced operation at Units 1 and 2.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $5,000.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Substation Pollutant Discharge Prevention & Removal - O&M**

**Project No. 19a, 19b**

**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. Florida Statute Chapter 403 states it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. This project includes the prevention and removal of pollutant discharges at FPL substations and will prevent further environmental degradation.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

During 2015, the equipment leak repair and regasketing work continues. Arsenic remediation work continues to be addressed at five (5) substations located in Miami-Dade County. Arsenic-impacted soils have been remediated at all the substations, except for Cutler Substation. An engineering control is currently under design for the recently identified arsenic soil impacts at the Cutler Substation, which were identified during the Cutler Power Plant decommissioning work. We anticipate the engineering control plan and covenant for Cutler Substation will be submitted to the county by end of 2015. Arsenic groundwater treatment systems have been operating successfully at the University, Coconut Grove and Princeton Substations. An arsenic groundwater treatment system for the Lawrence Substation has been proposed to Dade County for persistent arsenic at property boundary and we expect an approval by end of September 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

19a. Project expenditures are estimated to be $705,847 or 38.9% higher than previously projected. The variance is primarily due to obtaining equipment clearances (i.e., de-energize equipment) than expected, which in turn facilitated a higher than projected number of transformers being repaired during 2015.

19b. Project expenditures are estimated to be $554,316 or 29.9% lower than previously projected. The variance is primarily due to delays in obtaining equipment clearances (i.e., de-energize equipment), which in turn resulted in a lower than projected number of transformers being repaired in 2015.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are:

19a $2,734,611

19b $1,006,105

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: St. Lucie Turtle Net – O&M**

**Project No. 21**

**Project Description:**

FPL is limited in the number of lethal turtle takings permitted at its St. Lucie Power Plant by the Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on May 4, 2001 by the National Marine Fisheries Service (NMFS). The number of lethal takings permitted in a given year is calculated by taking one percent of the total number of loggerhead and green turtles captured in that year. The Incidental Take Statement separately limits the number of lethal takings of Kemp's Ridley turtles to two per year over the next ten years, and the number of lethal takings of either Hawksbill or Leatherback turtles to one of those species every two years over the next ten years.

In October 2009, the 5-inch primary barrier net failed due to influxes of algae that entered the canal and created a blockage of approximately 80% of the net. A new turtle net was installed in January 2015 that has a more robust barrier structure that can withstand significant algae events and similar environmental challenges.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Inspections and cleaning were performed on the net in order to remove algae and jellyfish buildup to maintain the effectiveness of the net in avoiding sea turtle fatalities.

**Project Fiscal Expenditures:**

(January 1, 2015 – December 31, 2015)

Project expenditures were $110,000 or 100% higher than previously projected. The variance is due to costs incurred for inspections and cleaning to remove algae and jellyfish buildup on the net that caused water velocity increases. An increase in water velocity can trap turtles on the net, cause injury and impair their safety.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $110,000.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Pipeline Integrity Management (PIM) – O&M**

**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, 2015 to December 31, 2015)

The ongoing integrity assessments were undertaken for the corporate liquid pipelines, along with associated evaluations and appropriate countermeasures. Inline inspection of TMR 30" and 18" pipelines along with TMT 16" pipeline were completed in 2015. The Final Inspection report on the 18" pipeline was provided by PII/GE (PII Solutions/General Electric) and 10 inspection/repair digs were identified. As part of the 180-day repair condition issued by the DOT, digs are required to be completed by October 14, 2015. Currently, the reports on inspections for the TMR 30" and TMT 16" pipelines have not been released by the Inline Inspection vendor.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $466,270 or 120.0% higher than previously projected. The variance is primarily due to deferral of planned smart pig inspections of both Martin pipelines from 2014 to 2015 due to the following:

- To pig the 18" pipeline, FPL needs approximately 200,000 bbls of excess room at the plant tank to accommodate oil used during pigging. Due to the lower price of natural gas versus the price of No. 6 oil, the plant did not burn oil and as a result, there was insufficient capacity available at the plant tank to support pigging the line.
- For the Martin 30" pipeline, there was a delay in the completion of port construction activities by the Port Authority, which resulted in delaying dock unloading pit work at the Port of Palm Beach required to allow vessels to unload fuel oil. Without the ability to receive a vessel, the Martin terminal 30" pipeline could not be online for planned inline inspection which was scheduled in 2014 and was rescheduled in 2015.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Projections**:

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $196,500.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: SPCC (Spill Prevention, Control, and Countermeasures) - O&M**
**Project No. 23**

**Project Description:**

The EPA first established the SPCC Program in 1973 when the agency 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). The purpose of the regulation was to prevent discharges of oil from reaching the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation 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. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

- has a combined aboveground oil storage capacity of more than 1,320 gallons, or a total underground oil storage capacity exceeding 42,000 gallons (Note: the underground storage capacity does not apply to those tanks subject to all of the technical requirements of the federal underground storage tank rule found in 40 CFR 280 or a State approved program); and
- due to its location, could be reasonably expected to discharge oil in quantities that may be harmful into or upon the navigable waters of the United States or adjoining shorelines.

In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of aboveground tanks within the framework of existing legislative authority. The result was the EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required the EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002. A deficiency was found at the Turkey Point Unit 3 Emergency Diesel Generator and Unit 4 Auxiliary Transformer areas. In order to meet compliance regulations, Engineering is currently evaluating project alternatives which will meet compliance regulations for secondary containment systems. Based on these analyses, the Station will construct facilities which will meet or exceed requirements to catch any spilled fuel and oil upon delivery, in these areas.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

FPL is continually updating a massive SPCC plan that contains 622+ facilities. The updates are required to maintain SPCC compliance when oil-filled equipment is relocated, removed, upgraded, or added to a substation. All substation inspections, required by regulations, are being performed on a quarterly basis and all information is being captured via electronic means. The information is directly uploaded from the field location into a complex database. This process has improved efficiency and data accuracy. FPL continues

to use an innovative perimeter oil barrier material that allows rainwater to flow through but solidifies when in contact with petroleum liquids. This material has proven effective to allow rainwater to flow off the property, and conversely prevents oil from migrating.

FPL is continually updating the Facility Response Plans for all electrical power plants and terminals. These updates incorporate changes to equipment, drainage systems, and containment throughout the year including Biodiesel Fuel Tank at Martin Terminal; Fuel Oil Fill Line modification at Turkey Point; and Storm Surge Protection at Cape Canaveral, Riviera Beach, Fort Myers, and Manatee Terminal. The Martin Plant completed installation of the Electrostatic Precipitators and associated equipment, stormwater management, wastewater management, and secondary containment systems. Engineering evaluated alternatives for secondary containment improvements and repairs at Martin Plant and West County Energy Center that will be implemented in 2016. Ongoing construction activities at Port Everglades Energy Center continue through early 2016.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $281,195 or 23.3% lower than expected, because work associated with the Maintenance of Stationary Above Ground Fuel Storage Tanks project was inadvertently charged to the SPCC project in 2014. A correcting entry was made in February 2015. Additionally, there was a staffing reduction of one full time and one part time position and an open position has not been filled.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $975,871.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Manatee Reburn – O&M**

**Project No. 24**

**Project Description:**

This project involves installation of reburn technology in Manatee Units 1 and 2. Reburn is an advanced nitrogen oxides (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 local concerns about 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. The FDEP and FPL agreed that reburn technology was the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Limited replacement of burner gas valves has begun in 2014 with the remainder to complete in 2015. The Unit #1 Burner component inspection and repairs is scheduled for the fall of 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $16,777 or 4.8% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $191,795.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Lowest Quality Water Source (LQWS) – O&M**

**Project No. 27**

**Project Description:**

The LQWS Project is required in order to comply with permit conditions in the Consumptive Use Permits (CUPs) 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 permit conditions therefore "apply to electric utilities and are designed to protect the environment" as contemplated by section 366.8255. 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 CUPs. For the Sanford facility, Condition 15 of CUP No. 9202, issued in June 2000, requires the lowest quality of water to be used that is feasible to meet the needs of the facility. The LQWS project at Sanford Plant is currently operational.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

The project at the Sanford Plant is currently operational. For 2015, our water treatment system operator, MPW, will bill us according to the cost of running the system, chemicals included, based on amount of water processed from the cooling pond.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $26,443 or 16.3% lower than previously projected. The variance is primarily due to reduced water supply from our source due to pump issues and the inability to run the water treatment system during unit reliability outages of Sanford Unit 4 and 5 that required switchgear de-energizations needed for preventative maintenance. LQWS usage is anticipated to increase in the coming months due to improvements to that system and as a result of increased water usage in the summer months due to increased unit dispatch. Use of the LQWS, when feasible, is required as a condition of the Water Use Permit in compliance with St Johns Water Management District rules. Cooling pond water at the Sanford Plant is considered LQWS and it use is required to the extent possible, rather than aquifer water. The purpose of the permit limitations for use of aquifer water are for the conservation of higher quality water taken from the environment.

**Project Projections**:

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $144,000.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: CWA 316(b) Phase II Rule – O&M**

**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 2 million gallons per day (MGD) or more of water from rivers, streams, lakes, reservoirs, estuaries, oceans or other Waters of the United States (WOTUS) 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 (CWIS) to minimize adverse environmental impacts. The Florida Department of Environmental Protection (FDEP) 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.

In the 316 (b) Rule, the EPA approved seven (7) impingement mortality (IM) control options, rather than requiring facilities to meet unrealistic numeric IM reduction limits that were contained in the proposed Rule. Offshore velocity caps and closed cycle cooling (cooling towers and cooling ponds) are pre-approved options. This means St. Lucie Plant, which has offshore velocity caps and Manatee, Martin, Sanford, SJRPP and Scherer Plants, which have cooling towers or cooling ponds, should have minimal expenditures required to comply with the IM standards. All facilities that withdraw 125 million gallons per day will undertake Entrainment Mortality (EM) studies that will determine if additional technology is required at any of these facilities to meet the EM BTA standards. Cape Canaveral, Ft. Myers, Lauderdale, Port Everglades, Riviera and St. Lucie will be required to undertake these EM studies. Requirements for additional EM controls to demonstrate BTA are determined on a site-by-site basis by comparing the benefits (i.e. value of organisms "saved" by EM additional EM controls) to cost of those controls.

In addition, through the process of understanding the final 316 (b) Rule, FPL, in conversations with the EPA and the DEP, became aware that horseshoe crabs, which are collected in large numbers at Cape Canaveral and were disposed of, are considered to be "shellfish" and therefore actions must be taken to reduce IM mortality associated with their presence in the plant's intake.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

A contractor was selected via a bidding process to assist FPL in developing a strategy for compliance with the 316 (b) Rule as well as the development and execution of studies required by the 316 (b) Rule to determine the appropriate BTA for minimizing IM and EM mortality at all of FPL's affected facilities. This work was begun in June of 2015 and will continue through the 2021 timeframe.

In addition, modifications were made to the temporary underwater horseshoe crab exclusion fence which was installed in late 2014 at the entrance to the cooling water intake of the Cape Canaveral Plant. This fence was designed to deter horseshoe crabs from entering the intake area and then getting impinged on the course screens located in front of the individual unit cooling water intake areas. A program was put in place to manually return any horseshoe crabs that are impinged on the plant intake to the Indian River. FPL held several meetings with the Florida Freshwater Fish and Wildlife Conservation Commission (FWC), the FDEP, and the National Marine Fisheries Service to discuss the results of horseshoe crab mortality reduction and relocation effort. Based on the outcome of these meetings, permitting and engineering was begun in 2015 and will likely continue into 2016 for the construction of a permanent horseshoe crab barrier further east of the current fence. It is possible, based on the effectiveness evaluation of this new barrier, that a return system will also be constructed at a later date.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $453,555 or 40.3% lower than previously projected. The variance is primarily due to the Florida Department of Environmental Protection's decision to delay the initiation of the compliance requirement until the beginning of the 2015 NPDES permit cycles. Actual compliance-related activities (i.e. strategy development, agency meetings and required studies) commenced for all plants in June 2015. Original estimates assumed that many of the plants' studies would commence in 2014.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $520,780**.**

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: SCR Consumables - O&M**

**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 SCRs on each of the plants' four Heat Recovery System Generators (HRSG) for the control of nitrogen oxide (NOx) emissions. The Florida Department of Environmental Protection (FDEP) made the determination that the SCR system is considered Best Available Control Technology (BACT) for these types of units, with concurrence from the U.S. Environmental Protection Agency (EPA). The operation of the SCRs caused FPL to incur O&M costs for certain products that are consumed in the SCRs. These include anhydrous ammonia, calibration gases, and equipment wear parts requiring periodic replacement such as controllers, ammonia detectors, heaters, pressure relief valves, dilution air blower components, NOX control analyzers, catalyst and components.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Manatee Unit 3 completed the required 5-yr Process Hazard Analysis for RMP (Risk Management Plan). For the Martin plant, an internal tank inspection was completed in February of 2015. PSM RMP (Process Safety Management Plan) (Risk Management Plan) Audit was completed in March of 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $10,972 or 1.9% higher than previously projected.

**Project Projections**:

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $476,279.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Hydrobiological Monitoring Program (HBMP) - O&M**

**Project No. 30**

**Project Description:**

The Hydrobiological Monitoring Program is required by the Southwest Florida Water Management District (SFWMD) in the Conditions of Certification for Manatee Unit 3. The program involves the data collection of river chemistry, flow and vegetation conditions to demonstrate that the plant's withdrawals do not impact the environment in and along the river. The Hydrobiological Monitoring Program is a 10 year study, which started in 2003 during the construction phase of Unit 3 and was completed in 2013.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

An Interpretive report was submitted in August. The SFWMD may agree to discontinue vegetative mapping, aerial photography and ground mapping, along with data and Interpretive reports. Continue with river monitoring, calibration, maintenance and data collection to report any effects of time spent on the Emergency Diversion Schedule. Data acquisition and analysis, along with a report to SWFWMD is required any time the Emergency Diversion Schedule is used. An annual fee of $24,000 will be incurred for this work in 2015. In 2015, we replaced the gauges at each station on the Little Manatee River.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $5,000 or 22.2% higher than previously projected. The variance is primarily associated with replacement of gauges at each station on the Little Manatee River, which was not included in original projections.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $27,500.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: CAIR – O&M**

**Project No. 31**

**Project Description:**

In response to the EPA Clean Air Interstate Rule (CAIR), FPL initiated the CAIR Project to implement strategies to comply with Annual and Ozone Season NOx and SO2 emissions requirements. The CAIR project to date has included the Black & Veatch (B&V) study of FPL's control and allowance management options, an engineering study conducted by Aptech for the reliable cycling of the 800 MW units, the costs for the operation of SCRs constructed on SJRPP Units 1 and 2, costs for the operation of the Scrubber and SCR being installed on Scherer Unit 4, and the installation of CEMS for the peaking gas turbine units. The 800 MW Cycling Project was added to CAIR after 2006 submittal. Aptech Engineering provided engineering services for the first phase of a multiphase scope of work that will assure that the operating reliability is maintained in a cycling mode. The study costs to Aptech Engineering have been paid and a significant portion of the work has been completed on the Martin and Manatee 800 MW units. Several countermeasures were prioritized and scheduled for implementation in 2008 – 2011. The CEMS installation on the Gas Turbine Peaking Units has been completed with ongoing maintenance expenses for their operation. On December 3, 2008 Georgia EPD promulgated the GA Multi-Pollutant rule requiring installation of SCR and a Scrubber on Scherer Unit 4.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

800MW Cycling Project O&M activities in 2015 were primarily related to water demineralization and us of chemicals for treatment of biological fouling of condenser tubes.

Scherer project O&M includes routine maintenance of the SCR and scrubber and associated limestone sorbent costs for removal of SO2 within the scrubber and ammonia costs for control of NOx emissions within the SCR. SJRPP CAIR O&M includes routine maintenance of the SCR and the purchase of ammonia for use in the SCR to reduce NOx emissions.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $209,864 or 4.3% lower than previously projected. This was primarily the result of anticipated but not incurred legal and consultant expenses to challenge the provisions of the EPA's Cross State Air Pollution Rule (1 CSAPR). Following the U.S. Court of Appeals' July 28, 2015 decision to remand to the EPA the portions of the rule that affect Florida, FPL did not challenge the CSAPR and therefore did not or will not incur in 2015 any associated expenses. Additionally, costs associated with the Martin 800 MW Cycling Project were lower than projected as a result of lower than anticipated water treatment costs.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $7,168,062.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: MATS Project – O&M**

**Project No. 33**

**Project Description:**

The Clean Air Mercury Rule (CAMR) was promulgated by the Environmental Protection Agency (EPA) on March 15, 2005, imposing nation-wide 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. The rule is implemented in two phases with an initial compliance date of 2010 for Phase I and the final required reductions of Phase II in 2018. The State of Florida has begun the implementation of the requirements for reduction of Hg through rule making process. Plant St. John's River Power Park (SJRPP) Units 1 and 2, in which FPL has 20% ownership shares, are affected units under this rule and will require the installation of Hg controls and HgCEMS. Similarly, the State of Georgia has also begun their rule making process to implement the federal rule, which will affect FPL's ownership share of Plant Scherer Unit 4, also requiring the installation of HgCEMS and Hg controls. On June 29, 2015 the Supreme Court issued an opinion remanding the MATS rule back to the DC Circuit Court of Appeals deciding that the EPA could ignore costs when deciding to regulate power plants. The EPA has requested that the DC Circuit not vacate the rule and instead allow it to submit by April 2016 a cost-benefit analysis showing that the rule was appropriate and necessary. FPL must continue with the rule requirements until a decision to vacate the rule is issued by the Court, and regardless of that decision, must comply with the Georgia Multi-Pollutant rule at Scherer Unit 4.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

For Scherer, the baghouse continues operating per the requirements of the State of Georgia Multi Pollutant Rule. For SJRPP, the plant is investigating use of calcium bromide to ensure consistent emission compliance.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $275,909 or 11.6% higher than previously projected. The variance is primarily due to higher than originally estimated consumption of powder-activated carbon due to increased unit operation. This is partially offset by less than originally estimated environmental/legal support services required for MATS compliance.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $3,018,075.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Martin Plant Water System – O&M**

**Project No. 35**

**Project Description:**

The Martin Drinking Water System (DWS) is required to comply with the requirements the Florida Department of Environmental Protection (FDEP) regulation's rules for drinking water systems. The FDEP determined the system must be brought into compliance with newly imposed drinking water rules for trihalomethanes (TTHM) and Haleo Acetic Acid (HAA5). The upgrades to the potable water system caused FPL to incur capital costs for major component upgrades to the system in order to comply with the new requirements. These include nano filtration, air stripping, carbon and multimedia filtration. The operation of the potable system will cause FPL to incur O&M costs for certain products that are consumed during the water treatment process. These include carbon and multimedia bed media and nano filtration media.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

The system will continue to run throughout 2015. O&M dollars were expended on filter maintenance.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $38,609 or 146.2% higher than previously projected. The variance is primarily due to the Nano filtration membrane which includes housing, end caps and retaining ring needing to be replaced in 2015 rather than 2016 as originally projected. In addition, there was an increase in vendor charges for monthly cleaning and yearly carbon change-out not previously forecasted.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $35,800.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: DeSoto Next Generation Solar Energy Center – O&M**

**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 generating facility, which will convert sunlight directly into electric power. The facility utilizes tracking arrays that are designed to follow the sun as it traverses through the sky. In addition to the tracking arrays, this facility utilizes cutting edge solar panel technology. The project uses solar PV panels, the associated tracking system, and the electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid. The warranty period has expired and a spare parts strategy and store room was created by site personnel.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Through the end of June, 2015, Desoto's net energy production was 27,302 MWh. The five year master drive fan replacement and tracker assembly boot replacement was performed. A study is being performed to evaluate alternative methods of managing the vegetation beneath the panels. New servers were installed to replace outdated models and for updated monitoring capability. Site personnel continue to develop PV inverter maintenance procedures and long term site maintenance strategies.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $27,246 or 2.5% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $897,458.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Space Coast Next Generation Solar Energy Center – O&M**

**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 solar photovoltaic (PV) generating facility which converts sunlight directly into electric power. The facility utilizes a fixed PV array oriented to capture the maximum amount of electricity from the sun over the entire year. The project 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. The warranty period has expired and a spare parts strategy and store room at Desoto Solar was created.

The Space Coast project also includes building a 900 KW solar PV facility at the Kennedy Space Center (KSC) industrial area. This 900 KW solar site will be built and 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, 2015 to December 31, 2015)

Through end of June, 2015, Space Coast Solar's net energy production was 9,442 MWh. New servers were installed to replace outdated models and for updated monitoring capability.

The Kennedy Space Center site operated well. A new server was installed to replace an outdated model. The HVAC condenser for the inverter container was replaced. Through end of June, 2014, net energy production was 822 MWHs. Quarterly Operation and Maintenance reports are submitted to NASA in accordance with the lease agreement between NASA and FPL.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $17,136 or 6.0% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $288,893.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Martin Next Generation Solar Energy Center - O&M**

**Project No. 39**

**Project Description:**

The Martin Next Generation Solar Energy Center (Martin 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 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 will be 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 and track the sun to maintain the optimum angle to collect solar radiation. The collectors concentrate the sun's energy on heat collection elements located in the focal line of the parabolic reflectors. These heat collection elements contain a heat transfer fluid that is heated by the concentrated solar radiation to approximately 750 degrees Fahrenheit. The heat transfer fluid is then circulated to heat exchangers that will produce up to 75 MW of steam routed to the existing natural gas-fired combined cycle Unit 8 heat recovery steam generators.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

2015 Martin Solar accomplishments:

- Completed the installation of two micro-pumps at the HTF Main pump to increase the fluid flow to the pump seals.
- Completed the installation of 4 Leslie Valve cages to increase the Solar Feed water flow capacity.
- Completed the installation of 2 control valves to automatically vent gases from the HTF pump system
- Installed a new SCA Drive Unit in solar field three.
- Repaired several items on 27 Solar Loops to increase reliability
- Replaced 4 HTF Pump Seal sets

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $143,212 or 4.1% higher than previously projected. The variance is a result of the unplanned installation of support brackets at the ball joint locations within the Solar Field Loops. The Martin Solar Team identified that a design modification of the ball joints to include a new support bracket would reduce the stress on the joints and is projected to avoid a majority of the mechanical failures of the joints.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $3,754,487.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Greenhouse Gas Reduction Program - O&M**

**Project No. 40**

**Project Description:**

The purpose of FPL's proposed Electric Utility Greenhouse Gas (GHG) Reduction Program is to comply with the EPA policies that require reductions in emissions of GHGs from electric generating units. The first requirement from EPA was the mandatory GHG Reporting Rule promulgated on October 30, 2009. The EPA's Mandatory (GHG) Reporting Rule requires electric utilities to record emissions of GHGs, primarily CO2 from the combustion of fossil fuels, and report actual data in a 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. In 2014 the EPA proposed its GHG performance standards for new and existing power plants, referred to as the Clean Power Plan (CPP). The draft CPP rule proposed that all of FPL's existing fossil fuel fired power plants would be subject to the rule requirements with the exception of its peaking combustion turbines. On August 3, 2015 the EPA issued its final CPP rule for existing sources along with a proposed Federal Implementation Plan (FIP) and Model Trading rules. FPL would then need to comply with final rule requirements when they become effective.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Project accomplishments for 2015 include the training of employees responsible for use of the system and OEM software maintenance. The implementation included the installation and use of a GHG reporting system and the training of those employees responsible for imputing required data.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $8,852 or 12.6% higher than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $79,000.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Manatee Temporary Heating System – O&M**

**Project No. 41**

**Project Description:**

FPL is subject to specific and continuing legal requirements to provide warm water refuges for the endangered manatee at its Port Everglades (PPE), Ft. Myers (PFM), Lauderdale (PFL), Riviera (PRV) and Cape Canaveral Plants (PCC). FPL undertook the design, engineering, purchase, and installation of temporary manatee heating systems for PCC, PRV and PPE ("the Project ") while these plants were being "modernized". The Project was required pursuant to PRV's, PCC's and PPE's Manatee Protection Plans (MPP), as part of the State Industrial Wastewater Facility Permit Numbers: PRV FL0001546, Specific Condition 13, issued on February 16, 1998, PCC- FL0001473, Specific Condition 9, issued on August 10, 2005, and PPE – FL0001538, Specific Condition 7, approved by the FDEP on August 13, 1999. FPL's installation of a manatee temporary heating system at each site was intended to be implemented to provide warm water until each site completed the planned modernization of the existing power generation units and of the warm water flow from the generating unit cooling water returned. Additional environmental and biological monitoring requirements were required by the Power Plant Siting Act Conditions of Certification associated operation of the heaters during and following plant shut-downs associated with the modernizations. The modernization projects have been completed at PCC and PRV.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Following the completion of PRV's modernization, the temporary heater system was no longer required and was removed from service. For PCC, the site is operational; the heating system will serve as an emergency backup in the case that the entire Unit 3 block needs to be taken down for outage during the future manatee seasons. However, due to requirements of the U.S. Fish and Wildlife Service to reduce the possibility of impinging dead or severely compromised manatees on the PCC intake screens, PCC is undertaking a project in the 2015-16 (and possibly 2017) time frame to relocate the manatee heating area further from the plant intakes.

For PCC, the annual Florida Fish and Wildlife Conservation Commission (FWC) telemetry monitoring expense will be completed in 2015, and will not continue thereafter. PPE will continue project expenditures related to biological and environmental monitoring and survey reporting costs during the 2015-2016 manatee season. The manatee heating system for PPE will be removed after the 2015-2016 season as it will no longer be required when the facility enters commercial operation.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $35,902 or 10.8% lower than previously projected. The variance is primarily due to lower than originally projected costs for removal of the manatee thermal barrier wall that was installed as part of the Port Everglades Energy Center Manatee Heater project.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for January 2016 through December 2016 are $1,886,820.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Turkey Point Cooling Canal Monitoring Plan - O&M**

**Project No. 42**

**Project Description:**

Pursuant to Conditions IX and X of the Florida Department of Environmental Protection's (FDEP) Final Order Approving Site Certification, filed October 29, 2008, FPL submitted its initial draft of the proposed Cooling Canal Monitoring Plan associated with FPL's Turkey Point Uprate Project to the South Florida Water Management District (SFWMD). This plan requires an assessment of baseline conditions to provide information on the vertical and horizontal extent of the hypersaline groundwater plume and effect of that plume on ground and surface water quality, if any. Comments, concerns and requests for revisions or action items were received from the SFWMD as well as the FDEP. Miami-Dade Department of Environmental Resource Management (DERM) has incorporated into the current draft the proposed monitoring plan, dated July 16, 2009.

The TP CCM Plan was finalized by FPL and the agencies on October 14, 2009. The objective of FPL's TP CCM Plan is to implement the Conditions of Certification IX and X, which state that "the Revised Plan shall be designed to be in concurrence with other existing and ongoing monitoring efforts in the area and shall include but not necessarily be limited to surface water, groundwater and water quality monitoring, and ecological monitoring to delineate the vertical and horizontal extent of the hyper-saline plume that originates from the cooling canal system and to characterize the water quality including salinity and temperature impacts of this plume for the baseline condition; determine the extent and effect of the groundwater plume on surface water quality as a baseline condition; and detect changes in the quantity and quality of surface and groundwater over time due to the cooling canal system associated with the Uprate Project. The Revised Plan includes installation and monitoring of an appropriate network of wells and surface water stations.

Based on the data FPL has collected pursuant to the CCS monitoring plan, the FDEP, in consultation with the SFWMD and Miami Dade County (MDC), issued a final administrative order (AO) on December 23, 2014; well after FPL had filed its 2015 ECRC projections on August 22, 2014. The AO directs FPL to achieve a substantial reduction in 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 the FDEP outlining how it will do so. Under the AO, measures to achieve salinity reduction include: a) delivering new sources of water to the CCS to reduce hyper-salinity, and b) conducting CCS sediment removal activities to restore CCS design conditions that will assist in managing salinity.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

FPL continued to conduct the monitoring and reporting requirements of the TP CCM Plan, including data collection and publication of periodic reports. Additionally, FPL undertook water projects to deliver new sources of water to the CCS and sediment removal activities to restore design conditions. During 2015 four

water projects were completed. Three water wells (PW-1, SW-1, and SW-2) were developed and installed to provide additional water to reduce the salinity of the CCS. Pumps and pipelines were also installed to deliver excess stormwater from L-31 under an Emergency Order from the SFWMD. CCS sediment removal was conducted to redistribute CCS flows more evenly, to improve heat exchange efficiency. This results in a lower overall CCS temperature, and therefore a lower evaporation rate contributing to a lower CCS salinity. The sediment removal also improves the hydraulic connection between the CCS and underlying groundwater, an important element of the overall salinity-reduction effort.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $39,906,782 higher than previously projected. These costs are the result of multiple activities related to monitoring and addressing salinity issues within the Cooling Canal System ("CCS") and surrounding groundwater at Turkey Point. The variance is primarily due to costs that are being incurred in 2015 related to compliance with requirements to manage the hypersaline condition that has occurred in the system in recent years. FPL did not have enough information to project these compliance costs in 2014, when the 2015 projections for this project were prepared.

Based on the data FPL has collected pursuant to the CCS monitoring plan, the FDEP, in consultation with the South Florida Water Management District ("SFWMD") and Miami Dade County ("MDC"), issued a final administrative order ("AO") on December 23, 2014; well after FPL had filed its 2015 ECRC projections on August 22, 2014. The AO directs FPL to achieve a substantial reduction in 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 the FDEP outlining how it will do so. Under the AO, measures to achieve salinity reduction include: a) delivering new sources of water to the CCS to reduce hyper-salinity, and b) conducting CCS maintenance activities to restore CCS design conditions that will assist in managing salinity. Administrative challenges to the AO are presently pending and so FPL has not yet submitted its SMP. However, owing to the short period of time that FPL will have to achieve the required salinity reductions once the challenges are resolved, FPL has begun taking actions to deliver new sources of water to the CCS and restore the CCS design conditions, two measures that will play a core role in the SMP. FPL does not believe that it could meet the AO's timetable without getting started now (in 2015) with implementation of those measures.

In order to deliver new sources of water to the CCS, FPL is incurring costs for monitoring saline water wells, costs for re-installation and permitting of a piping system to deliver local excess storm water (i.e., continuation of the L31-E Canal activity that was also conducted in 2014), and costs related to pursuing authorizations for six Upper Floridan Aquifer ("UFA") wells authorized by an FDEP Site Certification Modification issued December 23, 2014. It should be noted that the Site Certification for the UFA wells is also under administrative challenge. Costs in this category account for $6,906,782 (or 17%) of the $39.9 million variance.

In order to restore CCS design conditions, FPL is conducting maintenance dredging in the CCS. This dredging will restore design flow distribution and connectivity between the CCS and surrounding groundwater. Modeling performed for FPL to evaluate its AO compliance strategy shows that restoring the design flow distribution, thereby reducing overall CCS temperatures and evaporation rates, and re-establishing connectivity between the CCA and groundwater are essential to creating conditions in which the lower salinity levels required by the AO are realistically achievable. Moreover, the dredging will enable the CCS to better manage salinity during low rainfall periods, thereby allowing FPL to maintain the targeted annual average salinity level required by the AO when rainfall is low. Costs in this category account for the remaining $33.0 million (or 83%) of the $39.9 million variance.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $28,001,800.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: 800MW Unit ESP Project – O&M**

**Project No. 45**

**Project Description:**

On December 21, 2011, the Environmental Protection Agency issued the final Mercury and Air Toxics Standard (MATS) rule as required under Section 112 of the Clean Air Act for regulation of Hazardous Air Pollutants (HAPs). This has the effect of requiring Electrostatic Precipitators (ESPs) for the 800 MW oil-fired units. Specifically, the final MATS rule established numerical emission limits for particulate material (PM) as a surrogate for all toxic metals, along with emission limits for acid gasses (hydrochloric and hydrofluoric acids). The numerical particulate emission limits require that FPL install particulate emission control devices on its Martin and Manatee 800 MW oil-fired units in order to retain its flexibility regarding the operation of those units on 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 will install ESPs on Manatee Units 1 and 2 and Martin Units 1 and 2. As discussed in the project progress report for Project 33, the Supreme Court has remanded the rule to the DC Circuit. Unless the Court vacates the EPA's MATS rule FPL must continue to comply with applicable rule requirements. However, regardless of the Court's decision regarding the MATS rule, FPL must still comply with the particulate emission limits within its operating permit that require operation of the ESPs during oil operation.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

The installation of ESPs on units 1 and 2 at Martin were completed and placed in service in 2014. The systems will continue to run through 2015 with O&M costs for preventative maintenance. These costs will continue each year in order to operate and maintain the system.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $313,393 or 22.5% lower than previously projected. The variance is primarily due to lower than projected run time on fuel oil than originally planned at the Manatee plant. At the Martin plant, the original budget included four employees charging the project for the entire year but only two employees are currently charging the project and the other two employees were hired in July. This reduces the payroll forecast for 2015. In addition, there was a reduction in maintenance costs because of new equipment and warranty coverage.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $1,205,861.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: St. Lucie Cooling Water Discharge Monitoring Project - O&M**

**Project No. 46**

**Project Description:**

In conjunction with the St. Lucie Plant extended power uprates (EPUs) and a Florida Department of Environmental Protection (FDEP) permit modification authorizing a 2 degrees Fahrenheit increase to the plant's discharge temperature limitations, the St. Lucie Plant Industrial Wastewater Facility Permit requires FPL to perform biological and thermal monitoring in the Atlantic Ocean, in the vicinity of FPL's St. Lucie Plant, in accordance with an FDEP Administrative Order (AO). The purpose of this monitoring project (biological and thermal monitoring) is to evaluate potential effects of the EPUs on the plant's indigenous ocean biological species and to ensure that the St. Lucie Plant remains in compliance with Florida environmental permits and regulations applicable to the discharge of heated water to an open ocean environment.

The Biological Plan of Study (BPOS) is required to collect data pre- and post- uprate completion, for no less than 24 months after completion of the uprates. Twelve post-EPU biological sampling events are currently scheduled to complete the BPOS. Following the last sampling event, a Biological Report will be submitted to the Florida Department of Environmental Protection (FDEP) for their review and approval.

The HWPOS is required to be performed for no less than 24 months following its commencement. A total of nine servicing/maintenance events are currently planned for data collection, followed by demobilization/final data collection and submittal of a Heated Water Report to the FDEP for their review and approval.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

The BPOS was completed in January 2015. The Heated Water Plan of Study (HWPOS) was completed in December of 2014. Both final reports were submitted to the FDEP in January of 2015. As of this time the reports are still under review by the FDEP, thus we have not received an official response from the Department acknowledging that the reports are acceptable. The BPOS and the HWPOS were conducted in accordance with requirements stipulated in the St. Lucie Industrial Waste Water Facility Permit.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures for 2015 are projected to be $158,823 or 58.4% lower than previously projected. The FDEP did not require St. Lucie to perform the last round of data collection, which resulted in lower than originally projected fieldwork and project management costs.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $25,000.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: NPDES Permits Project (National Pollutant Discharge Elimination System) – O&M**
**Project No. 47**

**Project Description:**

The Federal Clean Water Act requires all point source discharges into navigable waters from industrial facilities to obtain permits under the NPDES program. See 33 U.S.C. Section 1342. Pursuant to the EPA's delegation of authority, FDEP 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. In April 2009, the FDEP amended Rule 62-620.620 (3), F.A.C. requiring all new or renewed wastewater discharge permits for major facilities, including power plants, to 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 the NDPES permits are renewed. The purpose of the SWPPP is to identify possible pollutant sources that can affect the water quality of stormwater and to require best management practices (BMPs) that, when implemented, will reduce or eliminate any possible pollution impacts to stormwater. FPL had several NPDES permits renewed in 2011 and 2012, and all of FPL's NPDES permits have been renewed since this project was instituted. In late September of 2012, the St. Lucie Plant received a final NPDES permit which contained a requirement to conduct a total residual oxidant plan of study (TROPOS) that will demonstrate that the discharges from the St. Lucie cooling water system meet the State's Class III total residual oxidant water quality standard of 0,01 mg/l. The cost for the TROPOS was added to this project in 2014.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

- WET Testing – WET testing was conducted at Cape Canaveral, Lauderdale, Ft. Myers
- Riviera and St. Lucie Plants in 2015
- SWPPP Development - No SWPPP's were written by contractors in 2015
- TROPOS – The TROPOS was completed in 2015

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $1,320 or 1.9% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project O&M expenditures for the period January 2016 through December 2016 are $57,898.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Industrial Boiler MACT Project – O&M**

**Project No. 48**

**Project Description:**

40 CFR Part 63 Subpart JJJJJ Final Rule for National Emission Standards for Hazardous Air Pollutants (HAPS) for Area Sources: Industrial, Commercial, and Institutional Boilers was published on March 21, 2011. In the 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's boilers and heaters that are subject to the requirements of the rule must complete energy audits, inspections, boiler tune-ups and recordkeeping requirements.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

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 will have completed all required energy audits at its Ft Myers, Lauderdale, Martin, and West County facilities this year.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $4,496, or 74.9% higher than previously projected. The variance is a result of boiler tuning that was conducted earlier than originally planned.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project O&M expenditures for the period January 2016 through December 2016 are $52,500.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Thermal Discharge Standards Project – O&M**

**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. This rule is implemented through the National Pollutant Discharge Elimination System (NPDES) program. See 33 U.S.C. Section 1342. Pursuant to the U.S. Environmental Protection Agency's (EPA) approval, the Florida Department of Environmental Protection (FDEP) 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.

Facilities that cannot meet the FDEP 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.

Prior to 2008, 316(a) variance determinations were conducted using draft guidance from the EPA that was developed in 1977. If a variance from the state water quality standard for temperature was previously granted, facilities were not required to provide additional information regarding thermal discharges in their renewal application unless changes had been made to the thermal loading in the plant discharge. In 2008, the EPA issued additional guidance on this topic and, with the new guidance the EPA has taken a much more active role in granting variances resulting in requests for expanded biological and thermal modeling/monitoring studies to justify the variances.

In addition, many plants that have once-through cooling water systems that discharge heated effluent and were originally deemed compliant with Chapter 62-302.520 (1) (a) (c) have been under scrutiny by the FDEP. Oversight of these facilities is also implemented via the NPDES permitting process. During recent permit renewals, the FDEP, much like the EPA with the 316(a) variances, has taken a more stringent approach to the required demonstration that substantial damage to aquatic organisms is not occurring in the receiving water bodies.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

The Riviera Plan of Study was completed and demonstrated that the post-modernization impact of the plant's thermal discharge was minimal. No further action was required by the FDEP. At the Cape Canaveral Plant, the requirements of the approved Plan of Study were completed and indicated that the issuance of the 316

(a) variance for Cape Canaveral is very well justified and there is no need for further data collection at this time. The completed study was submitted as part of the Cape Canaveral NPDES permit renewal application process. FPL has not yet received a reply from the FDEP stating their concurrence with our conclusion.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $29,357 or 72.4% higher than previously projected. The variance is primarily due to the delayed submittal of the Thermal Plans of Study for both the Cape Canaveral and Riviera Beach plants. The delays for submitting both studies to the FDEP were attributable to a lack of agency funding for subcontractors and project support for the agencies. As a result of the delays, some expenses projected to be incurred in 2014 were instead incurred in 2015.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

There are no projected O&M expenditures for the January 2016 through December 2016 period.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Steam Electric Guidelines Revised Rule - O&M**

**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 current version of the rule was published in the Federal Register on November 19, 1982. On September 15, 2009, the EPA announced that they would undertake rulemaking to revise the rule because, "current regulations, which were issued in 1982, have not kept pace with changes that have occurred in the electric power industry over the last three decades." The EPA published a draft rule on June 7, 2013, with a final rule expected to be issued by September 25, 2015.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

The operating agent for Plant Scherer conducted various studies which looked at a number of possible technology solutions in an attempt to determine the costs for various methods of complying with the Steam Electric Guidelines Revised Rule under various assumptions presented in the proposed rule.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $395,234, whereas no expenditures were projected. The variance is primarily due to invoices associated with FPL's portion of the cost of studies conducted by Georgia Power Company for Plant Scherer to assess compliance costs that will be incurred in anticipation of the implementation of the Steam Electric guidelines Revisions. This revised rule is anticipated to be released in September 2015. The operating agent did not provide FPL with a cost estimate for these studies until the fourth quarter of 2014 after FPL had filed its 2015 projections.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

There are no projected O&M expenditures for the January 2016 through December 2016 period.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Gopher Tortoise Relocation Project – O&M**

**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 (PMR), Manatee (PMT) and Sanford (PSN) power plants over time, as well as in the oil tank farm embankments at PMR and PMT. 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 (i.e., 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, 2015 to December 31, 2015)

In 2015, gopher tortoise burrows were discovered at PSN and PMT as well as the PMT Fuel Oil Storage Terminal embankments that could compromise the embankments' integrity. In order to fill the burrows, the gopher tortoises were relocated by an authorized gopher tortoise agent.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project expenditures were $35,000 or 145.8% higher than previously projected. The increase was due to higher than projected gopher tortoise relocations at the Manatee sites.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project O&M expenditures for the period January 2016 through December 2016 are $24,000.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Numeric Nutrient Criteria – O&M**

**Project No. 52**

**Project Description:**

The EPA was under a federal court order to implement numeric nutrient criteria (NNC) for the reduction of total nitrogen and total phosphorus discharges and load in Florida freshwaters and estuarine and coastal waters to comply with the Federal Clean Water Act. The FDEP drafted its own NNC rule and on June 28, 2013, the EPA accepted the state numeric and narrative standards for freshwaters statewide. On September 26, 2013, the EPA accepted FDEP NNC standards for Florida's estuaries. The FDEP NNC rule will be implemented through NPDES Industrial Waste Water permit renewals to achieve the reduction of total nitrogen (TN) and total phosphorus (TP) discharges and loading in Florida freshwaters, estuarine and coastal waters.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

The Environmental Resource Council for the State of Florida adopted the proposed NNC for estuarine and coastal waters on December 1, 2014. The FDEP submitted the final coastal criteria to the EPA in May of 2015 with an anticipation of approval by the end of summer. This action will allow the FDEP to implement state numeric and narrative nutrient standards as approved by the EPA. In 2015, a consultant was retained to verify that the Ft. Myers and Cape Canaveral facilities TN and TP discharges would comply with the newly established NNC.

**Project Fiscal Expenditures**:

(January 1, 2015 to December 31, 2015)

Project expenditures were $38,000, whereas no expenditures were projected. The variance is due to additional expenditures for the Ft. Myers plant due to the FDEP revisiting the Total Maximum Daily Load (TMDL) for the Caloosahatchee River, as well as the commencement of implementation of the NNC for fresh waters. Additionally, consulting expenditures for assistance in verification of compliance with existing Waste Load Allocations for the plant as part of the Indian River Lagoon TMDL were incurred at FPL's Cape Canaveral Plant. NPDES permit applications for both plants are due in 2015 and this information is being submitted as part of the renewal process.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

There are no projected O&M expenditures for the January 2016 through December 2016 period.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Low NOx Burner Technology – Capital**

**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 NOx emissions by implementing Reasonably Available Control Technology (RACT). The Dade, Broward and Palm Beach county areas were classified as "moderate non-attainment" by the State of Florida and the EPA. FPL has six units in this affected area that require implementation of RACT for NOx emission reductions.

The Florida DEP designated Low NOx Burner Technology (LNBT) as RACT determining that it meets the requirement to reduce NOx emissions. Reductions are achieved by delaying the mixing of the fuel and air at the burner and creating a staged combustion process along the length of the flame. NOx formation is reduced because peak flame temperatures and availability of oxygen for combustion is reduced in the initial stages.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

All activities are complete.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $232 or 0.2% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $100,923.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Continuous Emission Monitoring System (CEMS) – Capital**

**Project No. 3b**

**Project Description:**

The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping, and reporting of SO2, NOx, CO, Carbon Dioxide emissions, as well as opacity data from affected air pollution sources. FPL has 57 units, which are affected and which have installed CEMS to comply with these requirements.

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 and opacity. These systems continuously extract and analyze gaseous samples for each power plant stack and have automated data acquisition and reporting capability. Operation and maintenance of these systems in accordance with the provisions of 40 CFR Part 75 is an ongoing activity, which follow the Title IV CEMS Quality Assurance Program Manual.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

This is an ongoing project. No new additions to plants for 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $36,329 or 6.8% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $507,575.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Clean Closure Equivalency – Capital**

**Project No. 4b**

**Project Description:**

In compliance with 40 CFR 270.1(c)(5) and (6), FPL developed Closure Equivalency Determinations (COEDS) for nine FPL power plants to demonstrate to the U.S. 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.

To demonstrate clean closure, soil sampling and ground water monitoring plans, implementation schedules and related reports must be submitted to the EPA. Capital costs are for the installation of monitoring wells (typically four per site) necessary to collect ground water samples for analysis.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

All activities are complete.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $17, or 1.4% higher than previously projected.

**Project Projections**:

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $1,131.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks – Capital**

**Project No. 5b**

**Project Description:**

Florida Administrative Code (F.A.C.) Chapter 62-761, previously 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

There were no capital expenditures associated with Above Ground Fuel Storage Tanks in 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $38,710 or 2.7% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $1,546,673.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

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

**Project No. 7**

**Project Description:**

In accordance with criteria contained in Chapter 62-762 of the Florida Administrative Code (F.A.C.) for storage of pollutants, FPL initiated the replacement of underground turbine lube oil piping to above ground installations at the St. Lucie Nuclear Power Plant.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

All activities are complete.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $15 or 1.0% higher than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $1,239.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Oil Spill Cleanup/Response Equipment – Capital**

**Project No. 8b**

**Project Description:**

The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five 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, 2015 to December 31, 2015)

All equipment is being maintained and replaced as necessary to maintain compliance with regulatory guidelines for response readiness. In 2015, FPL intends to replace three (3) oil spill response trailers and purchase two (2) additional trailer mounted motorized boom reels as part of the Corporate Oil Spill Response equipment.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment were $23,712 or 15.4% lower than previously projected. The variance is primarily due to greater than anticipated retirement of corporate oil spill response equipment at the Manatee site and less than anticipated new equipment needing to be purchased.

**Project Projections**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $148,938.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Relocate Storm Water Runoff – Capital**

**Project No. 10**

**Project Description:**

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

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

All activities are complete.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $124 or 1.6% higher than previously projected.

**Project Projections**:

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $7,258.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Scherer Discharge Pipeline- Capital**
**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 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 new facility discharge limitations to Berry Creek. As a result of these new 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, 2015 to December 31, 2015)
All activities are complete.

**Project Fiscal Expenditures**:
(January 1, 2015 to December 31, 2015)
Project depreciation and return on investment are estimated to be $712 or 1.4% higher than previously projected.

**Project Projections**:
(January 1, 2016 to December 31, 2016)
Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $47,125.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Wastewater Discharge Elimination & Reuse – Capital**

**Project No. 20**

**Project Description:**

Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants, and the Dade County DERM 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, 2015 to December 31, 2015)

All activities are complete.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $750 or 0.9% higher than previously projected.

**Project Projections**:

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $76,974.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: St. Lucie Turtle Net – Capital**

**Project No. 21**

**Project Description:**

FPL is limited in the number of lethal turtle takings permitted at its St. Lucie Power Plant by the Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on May 4, 2001 by the National Marine Fisheries Service (NMFS). The number of lethal takings permitted in a given year is calculated by taking one percent of the total number of loggerhead and green turtles captured in that year. The Incidental Take Statement separately limits the number of lethal takings of Kemp's Ridley turtles to two per year over the next ten years, and the number of lethal takings of either hawksbill or leatherback turtles to one of those species every two years over the next ten years. An effective 5-inch primary barrier net is vital to limiting the number of lethal turtle takes per year. In 2002, the existing net became deformed due to the influxes of jellyfish and algae entering the canal. With the Commission approval, a replacement and enhancement of the net system was performed. In 2007, the antifoulant and protective coating on the existing 5-inch net deteriorated and was experiencing UV damage. With Commission approval, FPL purchased and installed a new 5-inch net in 2009.

In October 2009, the 5-inch primary barrier net failed due to influxes of algae that entered the canal and created a blockage of approximately 80% of the net. A new turtle net was installed in January 2015 that has a more robust barrier structure that can withstand significant algae events and similar environmental challenges.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

The turtle net barrier construction was completed in January 2015. The design includes a bridge structure, net structure, turtle net lifting device, a backup replacement net as well as north and south debris handling station.

**Project Fiscal Expenditures:**

(January 1, 2015 – December 31, 2015)

Project depreciation and return on investment are estimated to be $107,088 or 12.2% lower than previously projected. The variance is primarily attributed to lower vendor implementation costs than originally projected due to favorable contractual terms.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $783,701.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Pipeline Integrity Management (PIM) – Capital**

**Project No. 22**

**Project Description:**

FPL is required to develop 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, 2015 to December 31, 2015)

There were no capital expenditures associated with this project in 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment were $41,498 or 11.6% lower than previously projected. The initial projection included the depreciation and return on investment for the replacement of TMR 18" pipeline block valve actuators as part of the Pipeline Integrity Management Project. Subsequently, it was determined that the original actuators were part of the base pipeline project and thus the costs for the replacement of the valve actuators, and associated depreciation and return on investment, should be treated consistently (base rate capital).

**Project Projections**:

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $307,123.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: SPCC (Spill Prevention, Control, and Countermeasures) – Capital**

**Project No. 23**

**Project Description:**

The EPA first established the SPCC Program in 1973 when the agency 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). The purpose of the regulation was to prevent discharges of oil from reaching into the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation 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. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

- has a combined aboveground oil storage capacity of more than 1320 gallons, or a total underground oil storage capacity exceeding 42,000 gallons (Note: the underground storage capacity does not apply to those tanks subject to all of the technical requirements of the federal underground storage tank rule found in 40 CFR 280 or a State approved program); and
- due to its location, could be reasonably expected to discharge oil in quantities that may be harmful into or upon the navigable waters of the United States or adjoining shorelines.

In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of above ground tanks within the framework of existing legislative authority. The result was EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required the EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002. A deficiency was found at the Turkey Point Unit 3 Emergency Diesel Generator and Unit 4 Auxiliary Transformer areas. In order to meet compliance regulations, Engineering is evaluating project alternatives which will meet compliance regulations for secondary containment systems. Based on these analyses, the station will construct facilities which will meet or exceed requirements to catch any spilled fuel and oil upon delivery in these areas.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Engineering is evaluating secondary containment systems for Turkey Point.

- Construction of the unloading dock at the Cape Canaveral Energy Center (CCEC) has been completed.
- Construction of stormwater detention basins at and stormwater box trenches at CCEC has been completed.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

- The Port Everglades Plant was demolished in 2013 and the new Port Everglades Energy Center (PEEC) is being constructed while the Gas Turbine Power Park remains available to operate.
- Modification of the Gas Turbine non-contact stormwater area and detention berm and installation of a new weir structure have been completed at the future PEEC.
- Installation of heat Transfer Fluid over-pressurization and containment system at Martin Solar Energy Center (MSEC) has been completed.
- The oil water separators at Martin Plant Units 3, 4, and 8 as well as MSEC have been completed.
- Demolition of natural gas equipment at the north gas regulating yard at Martin Plant has been completed.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment were $171,900 or 10.3% lower than previously projected. The variance is primarily attributed to a change in the in-service dates of the collection basin being installed at Turkey Point. The collection basin which was originally expected to be in service in December 2015 has been changed to June 2016.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $1,845,303.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Manatee Reburn – Capital**

**Project No. 24**

**Project Description:**

This project involves installation of reburn technology at Manatee Units 1 and 2. Reburn is an advanced nitrogen oxides (NOx) control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers. The process is a proven advanced technology, with applications of a reburn-like flue gas incineration technique dating back to the late 1960s, and developments for applications to large coal-fired power plants in the United States dating back to the early to mid-1980s.

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. The reburning zone is operated under conditions where NOx from the main combustion zone is converted to elemental nitrogen (which makes up 79% of the atmosphere).

In the 1996-97 time period, FPL invested a considerable effort evaluating the Manatee units for the application of reburn technology. FPL has recently reviewed the reburn system designs previously proposed for the Manatee units and concluded that a design for either oil or gas reburn would require very similar characteristics. This will require reburn fuel injectors to be located at the elevation of the present top row of burners, with reburn injectors on the boiler front and rear walls. For the present application the injectors will be required to have dual fuel (oil and gas) capability. In order to provide adequate residence time for the reburn process, it is proposed to locate the reburn overfire air (OFA) ports between the boiler wing walls and to angle them slightly to provide better mixing with the boiler flow. Because of the complexity of the boiler flow field and the port location, it was determined that OFA booster fans would be required to assist the air-fuel mixing and complete the burnout process. Installation of reburn technology for Manatee Units 1 and 2 offers the potential to reduce NOx emissions through a “pollution prevention” approach that does not require the use of reagents, catalysts, and pollution reduction or removal equipment. The FDEP and FPL agree that reburn technology is the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Capital project scheduled for 2015 includes replacement of the failing PMT1 Reburn EJ2 Fabric Expansion Joint. In addition, for 2016 we’re planning to install a burner deck platform above the 4th burner deck on both PMT1 and PMT2.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

Project depreciation and return on investment are estimated to be $29,810 or 0.9% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $3,074,050.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Pt. Everglades ESP (Electrostatic Precipitators) Technology – Capital**

**Project No. 25**

**Project Description:**

The requirements of the Clean Air Act direct the Environmental Protection Agency (EPA) to develop health-based standards for certain “criteria pollutants”. i.e. ozone (O3), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter (PM), nitrogen oxides (NOx), an lead (Pb). The EPA developed standards for the criteria pollutants and regulates the emissions of those pollutants from major sources by way of the Title V permit program. Florida has been granted authority by the EPA to administer its own Title V program, which is at least as stringent as the EPA requirements. Florida is able to issue, renew and enforce Title V air operating permits for sources within the state via 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the DEP. The Title V program addresses the six criteria pollutants mentioned earlier, and includes hazardous air pollutants (HAP). The EPA sets the limits of emissions of Hazardous Air Pollutants through the Maximum Achievable Control Technology (MACT).

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

No Power Generation plant additions occurred.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $10,477 or 0.1% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $16,757,728.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: UST Replacement/Removal – Capital**

**Project No. 26**

**Project Description:**

The Florida Administrative Code (FAC) Chapter 62-761.500, dated July 13, 1998, requires the removal or replacement of existing Category-A and Category-B storage tank systems with systems meeting the standards of Category-C storage tank systems by December 31, 2009. UST Category-A tanks are single-walled tanks or underground single-walled piping with no secondary containment that wwere 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, 2015 to December 31, 2015)

There were no activities in 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $1,262 or 11.6% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $8,863.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: CAIR Compliance – Capital**

**Project No. 31**

**Project Description:**

In response to the EPA's Clean Air Interstate Rule (CAIR), FPL initiated the CAIR Project to implement strategies to comply with Annual and Ozone Season NOx and SO2 emissions requirements. The CAIR project to date has included the Black & Veatch (B&V) study of FPL's control and allowance management options, an engineering study conducted by Aptech for the reliable cycling of the 800 MW units, the costs for the operation of SCRs constructed on SJRPP Units 1 and 2, costs for the operation of the scrubber and SCR installed on Scherer Unit 4, and the installation of CEMS for the peaking gas turbine units. The 800 MW Cycling Project was added to CAIR after the 2006 submittal. Aptech Engineering provided engineering services for the first phase of a multiphase scope of work that will assure that the operating reliability is maintained in a cycling mode. The study costs to Aptech Engineering have been paid and a significant portion of the work has been completed on the Martin and Manatee 800 MW units. The CEMS installation on the gas turbine peaking Units has been completed with ongoing maintenance expenses for their operation. On December 3, 2008 Georgia Environmental Protection Division promulgated the GA Multi-Pollutant rule requiring installation of SCR and a scrubber on Scherer Unit 4. On July 6, 2010, the EPA proposed the Transport Rule, which will leave requirements to comply with the CAIR regulations in place until 2012 when a new program will be implemented to further reduce SO2 and NOx emissions from fossil power plants.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

800MW Cycling - Completed the implementation of the major 800MW cycling countermeasures for Manatee Unit 1 and Martin Unit 2 during the first half of 2010.SJRPP Units 1 and 2 SCRs are now in operation and construction was completed on the Scherer FGD and SCR in May 2012. Performance guarantee testing of the SCR was completed in June 2012 and it is now in operation. Performance guarantee testing of the FGD was completed in September 2012 and it is now in operation.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment were $655,691 or 1.1% lower than previously projected. The variance is primarily due to a reduction in the allocation of Plant Scherer costs for common facility equipment capital additions to Unit 4.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $56,597,147.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: MATS Project – Capital**

**Project No. 33**

**Project Description:**

The Clean Air Mercury Rule (CAMR) was promulgated by the Environmental Protection Agency (EPA) on March 15, 2005, imposing nation-wide 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 December 2012 EPA finalized its replacement rule for CAMR as the Mercury and Air Toxics Standards (MATS). The MATS rule replaces and supersedes the requirements of CAMR. Plant St. John's River Power Park (SJRPP) Units 1 and 2, in which FPL has 20% ownership shares, are affected units under this rule and will require the reductions of acid gasses and HgCEMS. Similarly, the rule also requires that Plant Scherer evaluate its monitoring for pollutants regulated under the rule. On June 29, 2015 the Supreme Court issued an opinion remanding the MATS rule back to the DC Circuit Court of Appeals deciding that the EPA could ignore costs when deciding to regulate power plants. The EPA has requested that the DC Circuit not vacate the rule and instead allow it to submit by April 2016 a cost-benefit analysis showing that the rule was appropriate and necessary. FPL must continue with the rule requirements until a decision to vacate the rule is issued by the Court, and regardless of that decision, must comply with the Georgia Multi-Pollutant rule at Scherer Unit 4.

**Project Accomplishments:**

**(January 1, 2015 to December 31, 2015)**

The Scherer Unit 4 baghouse was placed into service April 4, 2010 meeting the Georgia Multi-Pollutant Rule requirements. The baghouse passed all performance guarantee tests in May 2010 and is now in continuous operation. SJRPP is conducting calcium bromide testing for MATS compliance which may result in addition of a permanent injection system.

**Project Fiscal Expenditures:**

**(January 1, 2015 to December 31, 2015)**

Project depreciation and return on investment were $52,986 or 0.5% lower than previously projected. The variance is primarily due to a reduction in the allocation of Plant Scherer costs for common facility equipment to Unit 4.

**Project Projections:**

**(January 1, 2016 to December 31, 2016)**

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $11,407,958.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

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

**Project No. 34**

**Project Description:**

The purpose of the proposed St. Lucie Plant Cooling Water System Inspection and Maintenance Project (the "Project") is to inspect and, as necessary, maintain the cooling water system (the "Cooling System") at FPL's St. Lucie nuclear 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 "ESA") The St. Lucie Plant is an electric generating station on Hutchinson Island in St. Lucie County, Florida. The plant consists of two nuclear-fueled 1,025 and 1,032 net MW units, both of which use the Atlantic Ocean as a source of water for once-through condenser cooling. This cooling water is supplied to the units via the Cooling System. The St. Lucie plant cannot operate without the Cooling System. Compliance with the ESA is a condition to the operation of the St. Lucie plant. Inspection and cleaning of the intake pipes is an "environmental compliance cost" under section 366.8255, Florida Statutes. The specific "environmental law or regulation" requiring inspection and cleaning of the intake pipes are terms and conditions that will be imposed pursuant to a Biological Opinion (BO) that is to be issued by the National Oceanic and Atmospheric Administration (NOAA) pursuant to section 7 of the ESA. The NOAA finalized the BO in early 2015. FPL is awaiting a copy of the BO that contains the terms and conditions. The NOAA sent the Nuclear Regulatory Commission (NRC) a letter dated December 19, 2006, confirming its intent to issue the BO and stating the requirements that will be imposed pursuant to the BO with respect to inspection and cleaning of the intake pipes. FPL is currently working with the NOAA to develop take limits, as well as testing, monitoring and remediation plans upon completion of the cooling system turtle Excluder device construction.

**Project Accomplishments:**

(January 1, 2015 thru December 31, 2015)

Engineering commenced in the fourth quarter of 2014 to develop a test turtle tank to ensure that the installation of a turtle excluder device will conform to the requirements of the BO. The tank is scheduled to be completed in 2015 allowing the biologist team to monitor captured turtles. Upon successful completion of the monitoring period at the end of 2016, the construction of the offshore turtle excluder device is scheduled to begin in the first half of 2017.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

No current expenditures in 2015.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are $0.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Martin Plant Drinking Water System Compliance – Capital**

**Project No. 35**

**Project Description:**

The Martin Drinking Water System (DWS) is required to comply with the requirements the Florida Department of Environmental regulations rules for drinking water systems. The Florida Department of Environmental Protection (FDEP) determined the system must be brought into compliance with newly imposed drinking water rules for trihalomethanes (TTHM) and Haleo Acetic Acid (HAA5). The upgrades to the potable water system will cause FPL to incur capital costs for major component upgrades to the system in order to comply with the new requirements. These include nano filtration, air stripping, carbon and multimedia filtration. The operation of the potable system will cause FPL to incur O&M costs for certain products that are consumed during the water treatment process. These include carbon and multimedia bed media and nano filtration media.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

The system is in service in 2008 and operating as designed. No changes.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return are estimated to be $106 or 0.4% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $23,571.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Low Level Radioactive Waste – Capital**

**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, 2008The 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 Plant (PSL). Turkey Point (PTN) will be implementing a similar project; however the PTN project will start later than the PSL project since PTN has some limited existing LLW storage capacity. Where practical, this project will be implemented as part of a fleet approach. The objective at PSL and PTN 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 PSL and PTN nuclear units until an alternate solution becomes available. The LLW on site storage facilities at PSL and PTN 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, 2015 to December 31, 2015)

The St. Lucie and Turkey Point facility is currently in use at this time.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $39,383 or 2.1% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are $1,854,128.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: DeSoto Next Generation Solar Energy Center – Capital**

**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 generating facility, which converts sunlight directly into electric power. The facility utilizes a tracking array that is designed to follow the sun as it traverses through the sky. In addition to the tracking array this facility utilizes cutting edge solar panel technology. The project involves the installation of the solar PV panels, tracking system and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

No plant additions are projected for 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return were $46,871 or 0.3% higher than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are $15,375,753.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Space Coast Next Generation Solar Energy Center – Capital**

**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 solar photovoltaic (PV) generating facility, which converts sunlight directly into electric power. The facility utilizes a fixed PV array oriented to capture the maximum amount of electricity from the sun over the entire year. The project involves the installation of the solar PV panels and 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.

The Space Coast project also includes building a 1000 KW solar PV facility at the Kennedy Space Center (KSC) industrial area. This 1000 KW 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, 2015 to December 31, 2015)

No plant additions were projected this year.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return were $28,381 or 0.4% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are $7,219,202.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Martin Next Generation Solar Energy Center – Capital**

**Project No. 39**

**Project Description:**

The Martin Next Generation Solar Energy Center ("Martin 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 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 involves the installation of parabolic trough solar collectors that concentrate solar radiation. The collectors track the sun to maintain the optimum angle to collect solar radiation. The collectors concentrate the sun's energy on heat collection elements located in the focal line of the parabolic reflectors. These heat collection elements contain a heat transfer fluid which is heated by the concentrated solar radiation to approximately 750 degrees Fahrenheit. The heat transfer fluid is then circulated to heat exchangers that will produce up to 75 MW of steam that will be routed to the existing natural gas-fired combined cycle Unit 8 heat recovery steam generators.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

2015 YTD Martin Solar accomplishments:

- Started construction on Solar HTF Pump VFD building HVAC to improve cooling capacity.
- Installed 8" actuator valves to improve control of system.
- Completed new power block containment area seal coating around pre-heaters.
- Completed solar field thermal camera programming to monitor solar field for HTF fluid leaks.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment were $288,268 or 0.6% lower than previously projected. The variance is primarily due to the result of placing the pre-heaters into service in 2014 and the unitization/retirements of that project occurring in January 2015 upon final close-out of the work order. The retirement unit was not identified until close out of the work order resulting in timing differences.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $44,503,043.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Manatee Temporary Heating System Project – Capital**

**Project No. 41**

**Project Description:**

FPL is subject to specific and continuing legal requirements to provide a warm water refuge for endangered manatees at its Riviera (PRV), Cape Canaveral (PCC) and Port Everglades (PPE) Plants. FPL has undertaken the design, engineering, purchase, and installation of a temporary manatee heating system at PRV, PCC, and PPE ("the Project"). The Project is required pursuant to PRV's, PCC's, and PPE's Manatee Protection Plans (MPP), as part of the State Industrial Wastewater Facility Permit Numbers FL0001546, Specific Condition 13, issued on February 16, 1998, FL0001473, Specific Condition 9, issued on August 10,2005, and FL0001538, Specific Condition 10, issued on July 22, 2010, respectively. In order to comply with the respective MPPs; FPL's installation of a temporary manatee heating system at PRV, PCC, and PPE has been implemented to avoid potential adverse impacts to manatees congregating at PRV's, PCC's, and PPE's manatee embayment areas. Manatees currently gather at the plants during the annual period from November 15 to March 31 at PRV and PPE and the annual period of October 15 to March 31 at PCC. FPL's installation of the manatee temporary heating system at each site must be implemented to provide warm water until the site has completed the planned modernization of the existing power generation units and return of warm water flow from the generating unit cooling water will be provided by operation of the new units.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

All activities are complete.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $299 or .1% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are $448,084.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Turkey Point Cooling Canal Monitoring Plan – Capital**

**Project No. 42**

**Project Description:**

Pursuant to Conditions IX and X of the Florida Department of Environmental Protection's (FDEP) Final Order Approving Site Certification, filed October 29, 2008, FPL submitted its initial draft of the proposed Cooling Canal Monitoring Plan associated with FPL's Turkey Point Uprate Project to the South Florida Water Management District (SFWMD). This plan requires an assessment of baseline conditions to provide information on the vertical and horizontal extent of the hypersaline groundwater plume and effect of that plume on ground and surface water quality, if any.

The Turkey Point Cooling Canal Monitoring Plan (TP CCM) Plan was finalized by FPL and the agencies mentioned above on October 14, 2009. The objective of FPL's TP CCM Plan is to implement the Conditions of Certification IX and X, which state that "the Plan shall be designed to be in concurrence with other existing and ongoing monitoring efforts in the area and shall include but not necessarily be limited to surface water, groundwater and water quality monitoring, and ecological monitoring to delineate the vertical and horizontal extent of the hyper-saline plume that originates from the cooling canal system and to characterize the water quality including salinity and temperature impacts of this plume for the baseline condition; determine the extent and effect of the groundwater plume on surface water quality as a baseline condition; and detect changes in the quantity and quality of surface and groundwater over time due to the cooling canal system associated with the Uprate Project. The plan includes installation and monitoring of an appropriate network of wells and surface water stations.

Based on the data FPL has collected pursuant to the CCS monitoring plan, the FDEP, in consultation with the South Florida Water Management District (SFWMD) and Miami Dade County (MDC), issued a final administrative order (AO) on December 23, 2014, well after FPL had filed its 2015 ECRC projections on August 22, 2014. The AO directs FPL to achieve a substantial reduction in 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 the FDEP outlining how it will do so. Under the AO, measures to achieve salinity reduction include: a) delivering new sources of water to the CCS to reduce hyper-salinity, and b) conducting CCS sediment removal activities to restore CCS design conditions that will assist in managing salinity.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

FPL continued to conduct the monitoring and reporting requirements of the TP CCM Plan, including data collection and publication of periodic reports. Additionally, FPL undertook water projects to deliver new sources of water to the CCS and sediment removal activities to restore design conditions. During 2015 four water projects were completed. Three water wells (PW-1, SW-1, SW-2) were developed and installed to provide additional water to reduce the salinity of the CCS. Pumps and pipelines were also installed to deliver

excess stormwater from L-31 under an Emergency Order from the SFWMD. CCS sediment removal was conducted to redistribute CCS flows more evenly and remove sediment that had built up in certain canals, inhibiting efficient heat exchange. This results in a lower overall CCS temperature, and therefore a lower evaporation rate contributing to a lower CCS salinity. The sediment removal also improves the hydraulic connection between the CCS and underlying groundwater, an important element of the overall salinity-reduction effort.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment were $257,399 or 58.8% higher than previously projected. The variance is primarily attributed to the addition of two water wells that went into service in June 2015, and six monitoring wells and five monitoring stations expected to go into service in September 2015 that were not reflected in the original projection. This was partially offset by a change in the in-service dates of the Upper Floridan Aquifer (“UFA”) and saline water wells at Turkey Point. The UFA wells, which were originally expected to be in service in December 2015, have been delayed to 2016 pending the outcome of administrative challenge.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are $999,521.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Martin Plant Barley Barber Swamp Iron Mitigation Project – Capital**

**Project No. 44**

**Project Description:**

The project involves the engineering and installation of a siphon and a new discharge system to turn the existing flow away from the Barley Barber Swamp and back into the Martin Plant Cooling Pond.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

A new siphon and discharge system was engineered and installed. The system has been placed into service. The system continues to operate as engineered.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment are estimated to be $78 or 0.4% lower than previously projected.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are $17,217.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: 800MW Unit ESP Project – Capital**

**Project No. 45**

**Project Description:**

On December 21, 2011, the Environmental Protection Agency issued the final Maximum Achievable Control Technology (MACT) rule, which has the effect of requiring Electrostatic Precipitators (ESPs) for the 800 MW oil-fired units. Specifically, the final MACT rule established numerical emission limits for particulate material (PM) as a surrogate for all toxic metals, along with emission limits for acid gasses (hydrochloric and hydrofluoric acids). The numerical particulate emission limits require that FPL install particulate emission control devices on its Martin and Manatee 800 MW oil-fired units in order to retain its flexibility regarding the operation of those units on oil. ESPs are the most cost-effective form of particulate emission control for the 800 MW oil-fired units. As to the final MACT rule's limits on acid gasses, FPL has the compliance option of limiting the moisture content of the oil it burns in those units. To comply, FPL will install ESPs on Manatee Units 1 and 2 and Martin Units 1 and 2. As discussed in the project progress report for Project 33, the Supreme Court has remanded the rule to the DC Circuit. Unless the Court vacates the EPA's MATS rule FPL must continue to comply with applicable rule requirements. However, regardless of the Court's decision regarding the MATS rule, FPL must still comply with the particulate emission limits within its operating permit that require operation of the ESPs during oil operation.

**Project Accomplishments:**

(January 1, 2015 to December 31, 2015)

Work on Martin Unit 1 commenced on June 30, 2013 and mechanical completion was accomplished on March 18, 2014. The provisional acceptance was achieved on April 16, 2014. Martin Unit 2 outage began on March 24, 2014 with provisional acceptance planned for the first quarter of 2015.

**Project Fiscal Expenditures:**

(January 1, 2015 to December 31, 2015)

Project depreciation and return on investment were $569,690 or 2.4% higher than previously projected. The variance is primarily due to an actual in-service date for the Martin Unit 2 ESP in December 2014 vs. the originally estimated in-service date of February 2015. This earlier in-service date resulted in higher than estimated depreciation expense and return on investment.

**Project Projections:**

(January 1, 2016 to December 31, 2016)

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are $24,235,887.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ENERGY DEMAND ALLOCATION % BY RATE CLASS

FORM: 42-6P

JANUARY 2016 THROUGH DECEMBER 2016

| (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 | 61.852% | 59.178% | 59,217,744,919 | 10,929,287 | 11,423,224 | 1.07403231 | 1.05682939 | 62,583,053,240 | 11,738,407 | 12,268,911 | 54.20416% | 59.09185% | 57.85852% |
| GS1/GST1/WIES1 | 66.247% | 59.916% | 5,968,723,003 | 1,028,515 | 1,137,196 | 1.07403231 | 1.05682939 | 6,307,921,890 | 1,104,658 | 1,221,385 | 5.46339% | 5.56092% | 5.75989% |
| GSD1/GSDT1/HLFT1 | 73.676% | 69.259% | 25,780,251,707 | 3,994,442 | 4,249,185 | 1.07391916 | 1.05674326 | 27,243,107,232 | 4,289,708 | 4,563,281 | 23.59568% | 21.59465% | 21.51981% |
| OS2 | 91.626% | 14.373% | 10,815,996 | 1,348 | 8,591 | 1.06416126 | 1.02711572 | 11,109,280 | 1,434 | 9,142 | 0.00962% | 0.00722% | 0.04311% |
| GSLD1/GSLDT1/CS1/CST1/HLFT2 | 74.079% | 67.358% | 10,617,262,134 | 1,636,121 | 1,799,376 | 1.07248674 | 1.05568781 | 11,208,514,210 | 1,754,718 | 1,929,806 | 9.70787% | 8.83336% | 9.10071% |
| GSLD2/GSLDT2/CS2/CST2/HLFT3 | 88.522% | 82.000% | 2,553,194,139 | 329,253 | 355,439 | 1.06126026 | 1.04667484 | 2,672,364,067 | 349,423 | 377,213 | 2.31458% | 1.75902% | 1.77888% |
| GSLD3/GSLDT3/CS3/CST3 | 86.943% | 68.004% | 163,603,794 | 21,481 | 27,463 | 1.02151776 | 1.01703760 | 166,391,210 | 21,943 | 28,054 | 0.14411% | 0.11046% | 0.13230% |
| SST1T | 101.745% | 26.904% | 84,383,192 | 9,468 | 35,804 | 1.02151776 | 1.01703760 | 85,820,879 | 9,672 | 36,574 | 0.07433% | 0.04869% | 0.17248% |
| SST1D1/SST1D2/SST1D3 | 79.432% | 36.909% | 14,030,773 | 2,016 | 4,340 | 1.03475918 | 1.02711572 | 14,411,228 | 2,086 | 4,490 | 0.01248% | 0.01050% | 0.02118% |
| CILC D/CILC G | 88.215% | 85.693% | 2,774,212,820 | 359,001 | 369,563 | 1.05938613 | 1.04601130 | 2,901,857,958 | 380,321 | 391,510 | 2.51334% | 1.91456% | 1.84631% |
| CILC T | 92.778% | 85.467% | 1,352,648,209 | 166,431 | 180,669 | 1.02151776 | 1.01703760 | 1,375,694,088 | 170,012 | 184,557 | 1.19151% | 0.85585% | 0.87034% |
| MET | 72.219% | 64.980% | 90,613,286 | 14,323 | 15,919 | 1.03475918 | 1.02711572 | 93,070,330 | 14,821 | 16,472 | 0.08061% | 0.07461% | 0.07768% |
| OL1/SL1/PL1 | 581.721% | 49.036% | 637,607,559 | 12,512 | 148,434 | 1.07403231 | 1.05682939 | 673,842,408 | 13,438 | 159,423 | 0.58363% | 0.06765% | 0.75182% |
| SL2, GSCU1 | 99.882% | 98.740% | 114,374,076 | 13,072 | 13,223 | 1.07403231 | 1.05682939 | 120,873,885 | 14,040 | 14,202 | 0.10469% | 0.07068% | 0.06697% |
| Total | | | 109,379,465,607 | 18,517,270 | 19,768,423 | | | 115,458,031,906 | 19,864,682 | 21,205,020 | 100.00000% | 100.00000% | 100.00000% |

[a] Projected AVG 12 CP load factor based on 2012-2014 load research data and 2016 projections.

[b] Projected AVG 12 GCP load factor based on 2012-2014 load research data and 2016 projections.

[c] Projected KWH sales for the period January 2016 through December 2016.

[d] Calculated: (Col 4)/(8,760 * Col 2)

[e] Calculated: (Col 4)/8,760 * Col 3)

[f] Based on projected 2016 demand losses.

[g] Based on projected 2016 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

Note: There are currently no customers taking service on Schedules ISST1(D) or ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 Factor.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF ENVIRONMENTAL COST RECOVERY CLAUSE FACTORS

FORM: 42-7P

JANUARY 2016 THROUGH DECEMBER 2016

| (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 ($/KWH) [i] |
| RS1/RTR1 | 54.20416% | 59.09185% | 57.85852% | 45,578,425 | 108,331,215 | 1,820,083 | 155,729,724 | 59,217,744,919 | 0.00263 |
| GS1/GST1/WIES1 | 5.46339% | 5.56092% | 5.75989% | 4,593,978 | 10,194,652 | 181,192 | 14,969,821 | 5,968,723,003 | 0.00251 |
| GSD1/GSDT1/HLFT1 | 23.59568% | 21.59465% | 21.51981% | 19,840,801 | 39,588,783 | 676,959 | 60,106,543 | 25,780,251,707 | 0.00233 |
| OS2 | 0.00962% | 0.00722% | 0.04311% | 8,091 | 13,239 | 1,356 | 22,686 | 10,815,996 | 0.00210 |
| GSLD1/GSLDT1/CS1/CST1/HLFT2 | 9.70787% | 8.83336% | 9.10071% | 8,163,015 | 16,193,913 | 286,285 | 24,643,213 | 10,617,262,134 | 0.00232 |
| GSLD2/GSLDT2/CS2/CST2/HLFT3 | 2.31458% | 1.75902% | 1.77888% | 1,946,248 | 3,224,750 | 55,959 | 5,226,957 | 2,553,194,139 | 0.00205 |
| GSLD3/GSLDT3/CS3/CST3 | 0.14411% | 0.11046% | 0.13230% | 121,181 | 202,509 | 4,162 | 327,852 | 163,603,794 | 0.00200 |
| SST1T | 0.07433% | 0.04869% | 0.17248% | 62,502 | 89,258 | 5,426 | 157,186 | 84,383,192 | 0.00186 |
| SST1D1/SST1D2/SST1D3 | 0.01248% | 0.01050% | 0.02118% | 10,496 | 19,252 | 666 | 30,414 | 14,030,773 | 0.00217 |
| CILC D/CILC G | 2.51334% | 1.91456% | 1.84631% | 2,113,385 | 3,509,897 | 58,080 | 5,681,363 | 2,774,212,820 | 0.00205 |
| CILC T | 1.19151% | 0.85585% | 0.87034% | 1,001,900 | 1,569,006 | 27,379 | 2,598,285 | 1,352,648,209 | 0.00192 |
| MET | 0.08061% | 0.07461% | 0.07768% | 67,782 | 136,778 | 2,444 | 207,004 | 90,613,286 | 0.00228 |
| OL1/SL1/PL1 | 0.58363% | 0.06765% | 0.75182% | 490,751 | 124,019 | 23,650 | 638,420 | 637,607,559 | 0.00100 |
| SL2, GSCU1 | 0.10469% | 0.07068% | 0.06697% | 88,031 | 129,570 | 2,107 | 219,708 | 114,374,076 | 0.00192 |
| Total | | | | 84,086,585 | 183,326,841 | 3,145,748 | 270,559,175 | 109,379,465,607 | 0.00247 |

[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, Column 2
[e] Total CP Demand $ from Form 42-1P, Line 5, Column 3
[f] Total GCP Demand $ from Form 42-1P, Line 5, Column 4
[g] Col 5 + Col 6 + Col 7
[h] Projected KWH sales for the period January 2016 through December 2016.
[i] Col 8 / Col 9

Note: There are currently no customers taking service on Schedules ISST1(D) or ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 Factor.

Totals may not add due to rounding.

**FLORIDA POWER & LIGHT COMPANY**
**COST RECOVERY CLAUSES**

**Equity @ 10.50%**

**CAPITAL STRUCTURE AND COST RATES PER MAY 2015 EARNINGS SURVEILLANCE REPORT**

| | ADJUSTED RETAIL | RATIO | MIDPOINT COST RATES | WEIGHTED COST | PRE-TAX WEIGHTED COST |
|---|---|---|---|---|---|
| LONG_TERM_DEBT | 7,868,539,536 | 29.834% | 4.80% | 1.43% | 1.43% |
| SHORT_TERM_DEBT | 346,840,443 | 1.315% | 2.03% | 0.03% | 0.03% |
| PREFERRED_STOCK | 0 | 0.000% | 0.00% | 0.00% | 0.00% |
| CUSTOMER_DEPOSITS | 421,524,845 | 1.598% | 2.04% | 0.03% | 0.03% |
| COMMON_EQUITY | 12,106,290,409 | 45.901% | 10.50% | 4.82% | 7.85% |
| DEFERRED_INCOME_TAX | 5,629,438,935 | 21.344% | 0.00% | 0.00% | 0.00% |
| INVESTMENT_TAX_CREDITS | | | | | |
| ZERO COST | 0 | 0.000% | 0.00% | 0.00% | 0.00% |
| WEIGHTED COST | 2,138,560 | 0.008% | 8.25% | 0.00% | 0.00% |
| TOTAL | $26,374,772,728 | 100.00% | | 6.31% | 9.34% |

**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 | $7,868,539,536 | 39.39% | 4.796% | 1.889% | 1.889% |
| PREFERRED STOCK | 0 | 0.00% | 0.000% | 0.000% | 0.000% |
| COMMON EQUITY | 12,106,290,409 | 60.61% | 10.500% | 6.364% | 10.360% |
| TOTAL | $19,974,829,945 | 100.00% | | 8.253% | 12.250% |
| RATIO | | | | | |

| | |
|---|---|
| DEBT COMPONENTS: | |
| LONG TERM DEBT | 1.4309% |
| SHORT TERM DEBT | 0.0267% |
| CUSTOMER DEPOSITS | 0.0326% |
| TAX CREDITS -WEIGHTED | 0.0002% |
| TOTAL DEBT | **1.4904%** |
| EQUITY COMPONENTS: | |
| PREFERRED STOCK | 0.0000% |
| COMMON EQUITY | 4.8196% |
| TAX CREDITS -WEIGHTED | 0.0005% |
| TOTAL EQUITY | **4.8201%** |
| TOTAL | 6.3105% |
| PRE-TAX EQUITY | 7.8472% |
| PRE-TAX TOTAL | 9.3375% |

**Note:**

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

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Commission Forms 42-1P Through 42-8P**

**January 2016 - December 2016**
**Calculation of Projected Period Amount**

**Docket No. 150007-EI**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 9
PARTY: DUKE ENERGY FLORIDA, LLC
(DEF) – (DIRECT)
DESCRIPTION: Michael Delowery TGF-5

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

| 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) | $42,339,858 | $329,256 | $621,710 | $876,120 | $44,166,944 |
| b | Projected Capital Projects (Form 42-3P, Lines 7 through 9) | 22,049,877 | 0 | 1,414 | 3,176,702 | 25,227,993 |
| c | Total Jurisdictional Rev Req for the Projected Period (Lines 1a + 1b) | 64,389,735 | 329,256 | 623,124 | 4,052,822 | 69,394,937 |
| 2 | True-up for Estimated Over/(Under) Recovery for the Current Period January 2015 - December 2015 (Form 42-2E, Line 5 + 6 + 10) | (1,720,135) | (350,923) | 885,148 | 406,308 | (779,602) |
| 3 | Final True-up for the Period January 2014 - December 2014 (Form 42-1A, Line 3) | 1,428,470 | (98,371) | 4,238 | 84,706 | 1,419,043 |
| 4 | Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection Period January 2016 - December 2016 (Line 1 - Line 2 - Line 3) | 64,681,400 | 778,551 | (266,263) | 3,561,808 | 68,755,496 |
| 5 | Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072) | $64,727,970 | $779,111 | ($266,454) | $3,564,373 | $68,805,000 |

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**O&M Activities**
**(in Dollars)**

Form 42-2P

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)


| Line | Description | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | O&M Activities - System | | | | | | | | | | | | | |
| 1 | Transmission Substation Environmental Investigation, Remediation and Pollution Prevention | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $469,000 |
| 1a | Distribution Substation Environmental Investigation, Remediation and Pollution Prevention | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 621,000 |
| 2 | Distribution System Environmental Investigation, Remediation and Pollution Prevention | 3,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,000 |
| 3 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 51,723 | 51,723 | 51,723 | 51,723 | 695,676 |
| 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 | 8,824 | 8,824 | 10,978 | 8,657 | 9,562 | 9,661 | 9,921 | 9,934 | 9,931 | 8,793 | 7,740 | 8,223 | 111,050 |
| 5 | NOx Emissions Allowances Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 6 | Phase II Cooling Water Intake 316(b) - Base | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 250,000 |
| 6a | Phase II Cooling Water Intake 316(b) - Intm | 20,500 | 20,500 | 20,500 | 20,500 | 20,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 190,000 |
| 7.2 | CAIR/CAMR - Peaking | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 31,850 | 0 | 66,109 | 0 | 134,459 |
| 7.4 | CAIR/CAMR Crystal River - Base | 1,119,721 | 3,452,919 | 1,914,869 | 1,317,818 | 1,346,472 | 1,114,151 | 1,120,802 | 1,088,803 | 1,326,571 | 1,200,915 | 1,221,061 | 1,105,970 | 17,330,071 |
| 7.4 | CAIR/CAMR Crystal River - Energy | 1,421,824 | 1,336,488 | 1,001,927 | 1,382,142 | 1,426,980 | 1,465,949 | 1,456,055 | 1,483,137 | 1,483,419 | 1,514,175 | 1,311,791 | 1,499,939 | 16,783,826 |
| 7.4 | CAIR/CAMR Crystal River - A&G | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 141,192 |
| 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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Sea Turtle - Coastal Street Lighting - Distrib | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 50 | 50 | 50 | 0 | 0 | 450 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Energy | 0 | 0 | 18,232 | 0 | 4,290 | 7,500 | 0 | 0 | 18,232 | 0 | 4,290 | 7,500 | 60,044 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 48,283 | 48,283 | 43,283 | 43,283 | 529,400 |
| 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 | 266,003 | 266,003 | 406,003 | 542,253 | 366,003 | 266,003 | 302,253 | 266,003 | 266,003 | 302,253 | 266,003 | 266,003 | 3,780,792 |
| 18 | Coal Combustion Residual (CCR) Rule - Energy (C) | 150,333 | 75,333 | 75,333 | 294,083 | 294,083 | 294,083 | 294,083 | 75,333 | 75,333 | 75,333 | 50,333 | 50,333 | 1,804,000 |
| 2 | Total O&M Activities - Recoverable Costs | $3,512,115 | $5,718,478 | $3,994,753 | $4,087,364 | $3,989,901 | $3,716,858 | $3,717,624 | $3,457,671 | $3,766,426 | $3,631,555 | $3,452,362 | $3,488,005 | $46,533,115 |
| 3 | Recoverable Costs Allocated to Energy | 1,890,267 | 1,729,932 | 1,555,758 | 2,270,419 | 2,144,202 | 2,086,481 | 2,105,596 | 1,877,691 | 1,901,203 | 1,948,838 | 1,683,441 | 1,875,283 | 23,069,111 |
| | Recoverable Costs Allocated to Energy - NOx Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 4 | Recoverable Costs Allocated to Demand - Transm | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 469,000 |
| | Recoverable Costs Allocated to Demand - Distrib | 54,750 | 51,750 | 51,750 | 51,750 | 51,850 | 51,850 | 51,850 | 51,800 | 51,800 | 51,800 | 51,750 | 51,750 | 624,450 |
| | Recoverable Costs Allocated to Demand - Prod-Base | 1,132,221 | 3,465,419 | 1,952,369 | 1,330,318 | 1,358,972 | 1,151,651 | 1,133,302 | 1,101,303 | 1,364,071 | 1,213,415 | 1,233,561 | 1,143,470 | 17,580,071 |
| | Recoverable Costs Allocated to Demand - Prod-Intm | 81,598 | 81,598 | 81,598 | 81,598 | 81,598 | 73,598 | 73,598 | 73,598 | 64,223 | 64,223 | 64,223 | 64,223 | 885,676 |
| | Recoverable Costs Allocated to Demand - Prod-Peaking | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 31,850 | 0 | 66,109 | 0 | 134,459 |
| | Recoverable Costs Allocated to Demand - A&G | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 141,192 |
| 5 | Retail Energy Jurisdictional Factor | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | 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) | 1,849,176 | 1,689,187 | 1,529,691 | 2,220,389 | 2,084,201 | 2,025,099 | 2,037,318 | 1,812,034 | 1,837,596 | 1,884,537 | 1,627,322 | 1,831,640 | 22,428,190 |
| | Retail Energy Jurisdictional Factor - NOx Regulatory Asset (A) | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 8 | Jurisdictional Demand Recoverable Costs - Transm (B) | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 329,256 |
| | Jurisdictional Demand Recoverable Costs - Distrib (B) | 54,510 | 51,523 | 51,523 | 51,523 | 51,622 | 51,622 | 51,622 | 51,573 | 51,573 | 51,573 | 51,523 | 51,523 | 621,710 |
| | Jurisdictional Demand Recoverable Costs - Prod-Base (B) | 1,051,663 | 3,218,854 | 1,813,458 | 1,235,666 | 1,262,281 | 1,069,711 | 1,052,667 | 1,022,945 | 1,267,018 | 1,127,081 | 1,145,793 | 1,062,112 | 16,329,249 |
| | Jurisdictional Demand Recoverable Costs - Prod-Intm (B) | 59,324 | 59,324 | 59,324 | 59,324 | 59,324 | 53,508 | 53,508 | 53,508 | 46,692 | 46,692 | 46,692 | 46,692 | 643,912 |
| | Jurisdictional Demand Recoverable Costs - Prod-Peaking (B) | 0 | 35,012 | 0 | 0 | 0 | 0 | 0 | 0 | 30,552 | 0 | 63,414 | 0 | 128,978 |
| | Jurisdictional Demand Recoverable Costs - A&G (B) | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 131,616 |
| 9 | Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8) | $3,349,248 | $5,388,475 | $3,788,571 | $3,901,477 | $3,792,003 | $3,534,515 | $3,529,690 | $3,274,635 | $3,568,006 | $3,444,458 | $3,269,319 | $3,326,542 | $44,166,944 |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6
(C) As explained in the testimony of Garry Miller, $75K of 2015 temporary dust mitigation resulting from shift of permanent capital solution from October 2015 to October 2016 is included in Jan-16.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Capital Investment Projects-Recoverable Costs**
**(in Dollars)**

Form 42-3P

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)


| Line | Description | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investment Projects - System (A) | | | | | | | | | | | | | |
| 3.1 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| 4.1 | Above Ground Tank Secondary Containment - Peaking | 116,357 | 116,069 | 115,781 | 115,496 | 115,208 | 114,921 | 114,635 | 114,348 | 114,060 | 113,774 | 113,486 | 113,199 | 1,377,334 |
| 4.2 | Above Ground Tank Secondary Containment - Base | 24,937 | 24,911 | 24,885 | 24,858 | 24,832 | 24,806 | 24,780 | 24,754 | 24,728 | 24,702 | 24,676 | 24,649 | 297,518 |
| 4.3 | Above Ground Tank Secondary Containment - Intm | 2,700 | 2,696 | 2,691 | 2,687 | 2,683 | 2,678 | 2,674 | 2,669 | 2,664 | 2,660 | 2,655 | 2,650 | 32,107 |
| 5 | SO2/NOX Emissions Allowances - Energy | 90,075 | 87,387 | 84,690 | 81,995 | 79,305 | 76,610 | 73,915 | 71,217 | 68,521 | 65,828 | 63,146 | 60,466 | 903,155 |
| 7.1 | CAIR/CAMR Anclote- Intm | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.2 | CAIR/CAMR - Peaking | 18,804 | 18,775 | 18,745 | 18,711 | 18,684 | 18,651 | 18,622 | 18,590 | 18,558 | 18,531 | 18,499 | 18,468 | 223,638 |
| 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 | 42,190 | 43,219 | 43,666 | 44,115 | 44,563 | 45,007 | 45,456 | 45,904 | 46,348 | 46,797 | 47,246 | 47,692 | 542,203 |
| 7.4 | CAIR/CAMR Crystal River AFUDC - Energy | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 112,443 |
| 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 | 115 | 116 | 116 | 116 | 116 | 117 | 118 | 119 | 120 | 123 | 122 | 122 | 1,420 |
| 10.1 | Underground Storage Tanks - Base | 1,569 | 1,567 | 1,564 | 1,562 | 1,559 | 1,557 | 1,554 | 1,552 | 1,548 | 1,546 | 1,543 | 1,541 | 18,662 |
| 10.2 | Underground Storage Tanks - Intm | 733 | 731 | 730 | 728 | 726 | 725 | 722 | 721 | 720 | 717 | 716 | 714 | 8,683 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Intm | 154,003 | 153,692 | 153,383 | 153,073 | 152,763 | 152,453 | 152,143 | 151,833 | 151,523 | 151,214 | 150,903 | 150,593 | 1,827,576 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 37,668 | 37,612 | 37,555 | 37,499 | 37,443 | 37,386 | 37,330 | 37,273 | 37,217 | 37,160 | 37,103 | 37,047 | 448,291 |
| 17.1 | Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - | 1,430,070 | 1,427,963 | 1,425,857 | 1,423,751 | 1,421,646 | 1,419,540 | 1,417,433 | 1,415,327 | 1,413,221 | 1,411,115 | 1,409,009 | 1,406,902 | 17,021,828 |
| 17.2 | Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy | 246,827 | 250,632 | 257,005 | 262,083 | 263,275 | 279,122 | 278,455 | 277,789 | 277,122 | 276,456 | 275,790 | 275,123 | 3,219,684 |
| 18 | Coal Combustion Residual (CCR) Rule - Energy | (56,167) | 4,608 | 7,680 | 10,753 | 13,824 | 16,896 | 19,968 | 23,041 | 26,113 | 29,184 | 35,878 | 37,137 | 168,915 |
| 2 | Total Investment Projects - Recoverable Costs | $2,142,842 | $2,202,887 | $2,207,210 | $2,210,241 | $2,209,391 | $2,223,184 | $2,220,473 | $2,217,755 | $2,215,033 | $2,212,328 | $2,213,244 | $2,208,729 | $26,483,317 |
| 3 | Recoverable Costs Allocated to Energy | 1,757,843 | 1,817,572 | 1,822,157 | 1,825,451 | 1,824,863 | 1,838,924 | 1,836,471 | 1,834,017 | 1,831,564 | 1,829,113 | 1,830,296 | 1,826,045 | 21,874,316 |
| | Recoverable Costs Allocated to Distribution Demand | 115 | 116 | 116 | 116 | 116 | 117 | 118 | 119 | 120 | 123 | 122 | 122 | 1,420 |
| 4 | Recoverable Costs Allocated to Demand - Production - Base | 68,696 | 69,697 | 70,115 | 70,535 | 70,954 | 71,370 | 71,790 | 72,210 | 72,624 | 73,045 | 73,465 | 73,882 | 858,383 |
| | Recoverable Costs Allocated to Demand - Production - Intermediate | 181,027 | 180,658 | 180,296 | 179,932 | 179,566 | 179,201 | 178,837 | 178,471 | 178,107 | 177,742 | 177,376 | 177,013 | 2,148,226 |
| | Recoverable Costs Allocated to Demand - Production - Peaking | 135,161 | 134,844 | 134,526 | 134,207 | 133,892 | 133,572 | 133,257 | 132,938 | 132,618 | 132,305 | 131,985 | 131,667 | 1,600,972 |
| | Recoverable Costs Allocated to Demand - Production - Base (2012) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | Retail Energy Jurisdictional Factor | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | 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) | 1,719,630 | 1,774,762 | 1,791,627 | 1,785,225 | 1,773,798 | 1,784,825 | 1,776,920 | 1,769,887 | 1,770,287 | 1,768,762 | 1,769,281 | 1,783,548 | 21,268,554 |
| | Jurisdictional Demand Recoverable Costs - Distribution (B) | 114 | 115 | 115 | 115 | 115 | 116 | 117 | 118 | 119 | 122 | 121 | 121 | 1,414 |
| 8 | Jurisdictional Demand Recoverable Costs - Production - Base (C) | 63,808 | 64,738 | 65,126 | 65,516 | 65,906 | 66,292 | 66,682 | 67,072 | 67,457 | 67,848 | 68,238 | 68,625 | 797,309 |
| | Jurisdictional Demand Recoverable Costs - Production - Intermediate (C) | 131,612 | 131,344 | 131,081 | 130,816 | 130,550 | 130,285 | 130,020 | 129,754 | 129,489 | 129,224 | 128,958 | 128,694 | 1,561,825 |
| | Jurisdictional Demand Recoverable Costs - Production - Peaking (C) | 129,652 | 129,348 | 129,043 | 128,737 | 128,435 | 128,128 | 127,825 | 127,519 | 127,212 | 126,912 | 126,605 | 126,300 | 1,535,716 |
| | Jurisdictional Demand Recoverable Costs - Production - Base (2012) (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8) | $2,044,817 | $2,100,308 | $2,116,992 | $2,110,410 | $2,098,803 | $2,109,646 | $2,101,565 | $2,094,351 | $2,094,565 | $2,092,869 | $2,093,204 | $2,107,289 | $25,164,818 |

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, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
Page 5 of 45

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | |
| 3 | Less: Accumulated Depreciation | (777,505) | (783,149) | (788,793) | (794,437) | (800,081) | (805,725) | (811,369) | (817,013) | (822,657) | (828,301) | (833,945) | (839,589) | (845,233) | |
| 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) | $1,837,200 | $1,831,556 | $1,825,912 | $1,820,268 | $1,814,624 | $1,808,980 | $1,803,336 | $1,797,692 | $1,792,048 | $1,786,404 | $1,780,760 | $1,775,116 | $1,769,472 | |
| 6 | Average Net Investment | | $1,834,378 | $1,828,734 | $1,823,090 | $1,817,446 | $1,811,802 | $1,806,158 | $1,800,514 | $1,794,870 | $1,789,226 | $1,783,582 | $1,777,938 | $1,772,294 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 3,098 | 3,087 | 3,078 | 3,069 | 3,059 | 3,050 | 3,040 | 3,031 | 3,021 | 3,012 | 3,002 | 2,994 | 36,541 |
| | b. Equity Component Grossed Up For Taxes | | 12,742 | 12,701 | 12,663 | 12,624 | 12,584 | 12,544 | 12,507 | 12,466 | 12,428 | 12,388 | 12,349 | 12,311 | 150,307 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 67,728 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 25,284 |
| | e. Other (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| 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) | | 17,151 | 17,114 | 17,079 | 17,044 | 17,008 | 16,973 | 16,938 | 16,902 | 16,867 | 16,831 | 16,796 | 16,762 | 203,467 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $17,151 | $17,114 | $17,079 | $17,044 | $17,008 | $16,973 | $16,938 | $16,902 | $16,867 | $16,831 | $16,796 | $16,762 | $203,467 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | |
| 3 | Less: Accumulated Depreciation | (2,805,915) | (2,839,142) | (2,872,369) | (2,905,596) | (2,938,823) | (2,972,050) | (3,005,277) | (3,038,504) | (3,071,731) | (3,104,958) | (3,138,185) | (3,171,412) | (3,204,639) | |
| 4 | CWIP - Non-Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $8,495,889 | $8,462,662 | $8,429,435 | $8,396,208 | $8,362,981 | $8,329,754 | $8,296,527 | $8,263,300 | $8,230,073 | $8,196,846 | $8,163,619 | $8,130,392 | $8,097,165 | |
| 6 | Average Net Investment | | $8,479,275 | $8,446,048 | $8,412,821 | $8,379,594 | $8,346,367 | $8,313,140 | $8,279,913 | $8,246,686 | $8,213,459 | $8,180,232 | $8,147,005 | $8,113,778 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 14,317 | 14,261 | 14,205 | 14,148 | 14,093 | 14,037 | 13,980 | 13,924 | 13,867 | 13,812 | 13,755 | 13,699 | 168,098 |
| | b. Equity Component Grossed Up For Taxes | | 58,896 | 58,664 | 58,432 | 58,204 | 57,971 | 57,740 | 57,511 | 57,280 | 57,049 | 56,818 | 56,587 | 56,356 | 691,508 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 398,724 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 119,004 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $116,357 | $116,069 | $115,781 | $115,496 | $115,208 | $114,921 | $114,635 | $114,348 | $114,060 | $113,774 | $113,486 | $113,199 | $1,377,334 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $116,357 | $116,069 | $115,781 | $115,496 | $115,208 | $114,921 | $114,635 | $114,348 | $114,060 | $113,774 | $113,486 | $113,199 | $1,377,334 |
| 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) | | 111,614 | 111,338 | 111,062 | 110,788 | 110,512 | 110,237 | 109,962 | 109,687 | 109,411 | 109,137 | 108,860 | 108,585 | 1,321,194 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $111,614 | $111,338 | $111,062 | $110,788 | $110,512 | $110,237 | $109,962 | $109,687 | $109,411 | $109,137 | $108,860 | $108,585 | $1,321,194 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | 100,001 | 96,969 | 93,937 | 90,905 | 87,873 | 84,841 | 81,809 | 78,777 | 75,745 | 72,713 | 69,681 | 66,649 | 63,617 | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | $2,499,040 | $2,496,008 | $2,492,976 | $2,489,944 | $2,486,912 | $2,483,880 | $2,480,848 | $2,477,816 | $2,474,784 | $2,471,752 | $2,468,720 | $2,465,688 | $2,462,656 | |
| 6 | Average Net Investment | | $2,497,524 | $2,494,492 | $2,491,460 | $2,488,428 | $2,485,396 | $2,482,364 | $2,479,332 | $2,476,300 | $2,473,268 | $2,470,236 | $2,467,204 | $2,464,172 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 4,217 | 4,212 | 4,207 | 4,201 | 4,196 | 4,191 | 4,186 | 4,181 | 4,177 | 4,171 | 4,166 | 4,161 | 50,266 |
| | b. Equity Component Grossed Up For Taxes | | 17,347 | 17,326 | 17,305 | 17,284 | 17,263 | 17,242 | 17,221 | 17,200 | 17,178 | 17,158 | 17,137 | 17,115 | 206,776 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 36,384 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 4,092 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $24,937 | $24,911 | $24,885 | $24,858 | $24,832 | $24,806 | $24,780 | $24,754 | $24,728 | $24,702 | $24,676 | $24,649 | $297,518 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $24,937 | $24,911 | $24,885 | $24,858 | $24,832 | $24,806 | $24,780 | $24,754 | $24,728 | $24,702 | $24,676 | $24,649 | $297,518 |
| 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) | | 23,163 | 23,139 | 23,114 | 23,089 | 23,065 | 23,041 | 23,017 | 22,993 | 22,969 | 22,944 | 22,920 | 22,895 | 276,350 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $23,163 | $23,139 | $23,114 | $23,089 | $23,065 | $23,041 | $23,017 | $22,993 | $22,969 | $22,944 | $22,920 | $22,895 | $276,350 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | (60,186) | (60,711) | (61,236) | (61,761) | (62,286) | (62,811) | (63,336) | (63,861) | (64,386) | (64,911) | (65,436) | (65,961) | (66,486) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | $230,112 | $229,587 | $229,062 | $228,537 | $228,012 | $227,487 | $226,962 | $226,437 | $225,912 | $225,387 | $224,862 | $224,337 | $223,812 | |
| 6 | Average Net Investment | | $229,849 | $229,324 | $228,799 | $228,274 | $227,749 | $227,224 | $226,699 | $226,174 | $225,649 | $225,124 | $224,599 | $224,074 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 388 | 387 | 386 | 385 | 385 | 384 | 383 | 382 | 381 | 380 | 379 | 378 | 4,598 |
| | b. Equity Component Grossed Up For Taxes | | 1,596 | 1,593 | 1,589 | 1,586 | 1,582 | 1,578 | 1,575 | 1,571 | 1,567 | 1,564 | 1,560 | 1,556 | 18,917 |
| | 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) | | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 2,292 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |
| 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) | | 1,963 | 1,960 | 1,956 | 1,954 | 1,951 | 1,947 | 1,944 | 1,940 | 1,937 | 1,934 | 1,930 | 1,927 | 23,343 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $1,963 | $1,960 | $1,956 | $1,954 | $1,951 | $1,947 | $1,944 | $1,940 | $1,937 | $1,934 | $1,930 | $1,927 | $23,343 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0158150 $SO_2$ Emission Allowance Inventory | | $3,333,608 | $3,324,785 | $3,315,961 | $3,304,982 | $3,296,584 | $3,287,013 | $3,277,343 | $3,267,414 | $3,257,471 | $3,247,532 | $3,238,730 | $3,230,982 | $3,222,750 | $3,222,750 |
| | b. 0254020 Auctioned $SO_2$ Allowance | | (4,039) | (4,039) | (4,039) | (4,039) | (4,298) | (4,289) | (4,281) | (4,272) | (4,264) | (4,256) | (4,247) | (4,239) | (4,230) | (4,230) |
| | c. 0158170 NOx Emission Allowance Inventory | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Other (A) | | 7,258,313 | 6,955,883 | 6,653,453 | 6,351,024 | 6,048,594 | 5,746,164 | 5,443,735 | 5,141,305 | 4,838,875 | 4,536,446 | 4,234,016 | 3,931,586 | 3,629,156 | 3,629,156 |
| 2 | Total Working Capital | | $10,587,882 | $10,276,629 | $9,965,375 | $9,651,967 | $9,340,880 | $9,028,888 | $8,716,797 | $8,404,447 | $8,092,083 | $7,779,722 | $7,468,499 | $7,158,329 | $6,847,676 | $6,847,676 |
| 3 | Average Net Investment | | | $10,432,255 | $10,121,002 | $9,808,671 | $9,496,424 | $9,184,884 | $8,872,843 | $8,560,622 | $8,248,265 | $7,935,902 | $7,624,110 | $7,313,414 | $7,003,003 | |
| 4 | Return on Average Net Working Capital Balance (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 17,615 | 17,089 | 16,562 | 16,035 | 15,509 | 14,982 | 14,455 | 13,927 | 13,400 | 12,873 | 12,349 | 11,825 | 176,621 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 72,460 | 70,298 | 68,128 | 65,960 | 63,796 | 61,628 | 59,460 | 57,290 | 55,121 | 52,955 | 50,797 | 48,641 | 726,534 |
| 5 | Total Return Component (C) | | | $90,075 | $87,387 | $84,690 | $81,995 | $79,305 | $76,610 | $73,915 | $71,217 | $68,521 | $65,828 | $63,146 | $60,466 | 903,155 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0509030 $SO_2$ Allowance Expense | | | $8,824 | $8,824 | $10,978 | $8,399 | $9,571 | $9,670 | $9,929 | $9,943 | $9,940 | $8,802 | $7,748 | $8,232 | 110,858 |
| | b. 0407426 Amortization Expense | | | 0 | 0 | 0 | 259 | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | 191 |
| | 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) | | | 8,824 | 8,824 | 10,978 | 8,657 | 9,562 | 9,661 | 9,921 | 9,934 | 9,931 | 8,793 | 7,740 | 8,223 | 111,050 |
| 8 | Amortization of NOx CAIR Emission Allowances (A) | | | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | 3,629,156 |
| 9 | Total System Recoverable Expenses (Lines 5 + 7) | | | $401,328 | $398,641 | $398,098 | $393,082 | $391,297 | $388,701 | $386,265 | $383,581 | $380,882 | $377,051 | $373,316 | $371,119 | |
| | a. Recoverable Costs Allocated to Energy | | | 98,899 | 96,211 | 95,668 | 90,652 | 88,867 | 86,271 | 83,836 | 81,151 | 78,452 | 74,621 | 70,886 | 68,689 | |
| | b. Recoverable Costs Allocated to Energy - NOx CAIR Emisssion Allowances (A) | | | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | |
| 10 | a. Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | b. NOx Regulatory Asset Energy Factor (12/2014) (A) | | | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | |
| 11 | Retail Energy-Related Recoverable Costs (E) | | | $96,749 | $93,945 | $94,065 | $88,654 | $86,381 | $83,733 | $81,117 | $78,314 | $75,828 | $72,159 | $68,523 | $67,091 | 986,559 |
| 12 | Retail Demand-Related Recoverable Costs (F) | | | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 13 | Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | | $ 392,918 | $ 390,114 | $ 390,235 | $ 384,824 | $ 382,550 | $ 379,903 | $ 377,287 | $ 374,483 | $ 371,997 | $ 368,329 | $ 364,692 | $ 363,260 | $ 4,540,592 |

Notes:

(A) Unusable NOx emission allowances due expiration of Clean Air Interstate Rule (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 conisistent with Order No. PSC-11-0553-FOF-EI.

(B) Line 3 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) Line 5 is reported on Capital Schedule

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

(E) Line 9a x Line 10a

(F) Line 9b x Line 10b

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
Page 10 of 45

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | |
| 3 | Less: Accumulated Depreciation | (346,416) | (349,966) | (353,516) | (357,066) | (360,616) | (364,166) | (367,716) | (371,266) | (374,816) | (378,366) | (381,916) | (385,466) | (389,016) | |
| 4 | CWIP - Non-Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $1,589,692 | $1,586,142 | $1,582,592 | $1,579,042 | $1,575,492 | $1,571,942 | $1,568,392 | $1,564,842 | $1,561,292 | $1,557,742 | $1,554,192 | $1,550,642 | $1,547,092 | |
| 6 | Average Net Investment | | $1,587,917 | $1,584,367 | $1,580,817 | $1,577,267 | $1,573,717 | $1,570,167 | $1,566,617 | $1,563,067 | $1,559,517 | $1,555,967 | $1,552,417 | $1,548,867 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 2,680 | 2,675 | 2,670 | 2,662 | 2,658 | 2,651 | 2,646 | 2,639 | 2,632 | 2,629 | 2,621 | 2,614 | 31,777 |
| | b. Equity Component Grossed Up For Taxes | | 11,029 | 11,005 | 10,980 | 10,954 | 10,931 | 10,905 | 10,881 | 10,856 | 10,831 | 10,807 | 10,783 | 10,759 | 130,721 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 42,600 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 18,540 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $18,804 | $18,775 | $18,745 | $18,711 | $18,684 | $18,651 | $18,622 | $18,590 | $18,558 | $18,531 | $18,499 | $18,468 | 223,638 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $18,804 | $18,775 | $18,745 | $18,711 | $18,684 | $18,651 | $18,622 | $18,590 | $18,558 | $18,531 | $18,499 | $18,468 | 223,638 |
| 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) | | 18,038 | 18,010 | 17,981 | 17,948 | 17,922 | 17,891 | 17,863 | 17,832 | 17,802 | 17,776 | 17,745 | 17,715 | 214,523 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $18,038 | $18,010 | $17,981 | $17,948 | $17,922 | $17,891 | $17,863 | $17,832 | $17,802 | $17,776 | $17,745 | $17,715 | $214,523 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
Page 11 of 45

**Return on Capital Investments, Depreciation and Taxes**
**For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $713,122 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | |
| 3 | Less: Accumulated Depreciation | (106,469) | (114,097) | (121,725) | (129,353) | (136,981) | (144,609) | (152,237) | (159,865) | (167,493) | (175,121) | (182,749) | (190,377) | (198,005) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 59,427 | 118,854 | 178,281 | 237,707 | 297,134 | 356,561 | 415,988 | 475,415 | 534,842 | 594,268 | 653,695 | 713,122 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $3,844,399 | $3,896,197 | $3,947,996 | $3,999,795 | $4,051,594 | $4,103,393 | $4,155,192 | $4,206,990 | $4,258,789 | $4,310,588 | $4,362,387 | $4,414,186 | $4,465,985 | |
| 6 | Average Net Investment | | $3,870,298 | $3,922,097 | $3,973,896 | $4,025,694 | $4,077,493 | $4,129,292 | $4,181,091 | $4,232,890 | $4,284,689 | $4,336,487 | $4,388,286 | $4,440,085 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 6,649 | 6,850 | 6,938 | 7,026 | 7,114 | 7,199 | 7,288 | 7,376 | 7,462 | 7,550 | 7,638 | 7,725 | 86,815 |
| | b. Equity Component Grossed Up For Taxes | | 27,352 | 28,180 | 28,539 | 28,900 | 29,260 | 29,619 | 29,979 | 30,339 | 30,697 | 31,058 | 31,419 | 31,778 | 357,120 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 91,536 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (D) | | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 6,732 |
| | e. Other | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $42,190 | $43,219 | $43,666 | $44,115 | $44,563 | $45,007 | $45,456 | $45,904 | $46,348 | $46,797 | $47,246 | $47,692 | 542,203 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $42,190 | $43,219 | $43,666 | $44,115 | $44,563 | $45,007 | $45,456 | $45,904 | $46,348 | $46,797 | $47,246 | $47,692 | 542,203 |
| 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) | | 39,188 | 40,144 | 40,559 | 40,976 | 41,392 | 41,805 | 42,222 | 42,638 | 43,050 | 43,467 | 43,884 | 44,299 | 503,625 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $39,188 | $40,144 | $40,559 | $40,976 | $41,392 | $41,805 | $42,222 | $42,638 | $43,050 | $43,467 | $43,884 | $44,299 | $503,625 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**Schedule of Amortization and Return**
**For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-Products)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0154401 Ammonia Inventory | | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | 185,206 |
| | b. 0154200 Limestone Inventory | | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 |
| 2 | Total Working Capital | | $1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 |
| 3 | Average Net Investment | | | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | |
| 4 | Return on Average Net Working Capital Balance (A) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | $21,989 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 90,454 |
| 5 | Total Return Component (B) | | | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 112,443 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0502010 Ammonia Expense | | | 455,485 | 425,538 | 297,964 | 432,747 | 455,824 | 459,359 | 470,739 | 467,246 | 474,561 | 484,937 | 413,592 | 472,009 | 5,310,002 |
| | b. 0502040 Limestone Expense | | | 447,356 | 418,943 | 294,169 | 428,890 | 452,848 | 457,804 | 470,373 | 468,108 | 476,919 | 488,404 | 417,340 | 476,024 | 5,297,179 |
| | c. 0502050 Dibasic Acid Expense | | | 0 | 0 | 22,000 | 0 | 0 | 22,000 | 0 | 22,000 | 0 | 0 | 0 | 22,000 | 88,000 |
| | d. 0502070 Gypsum Disposal/Sale | | | 101,740 | 99,311 | 99,311 | 123,599 | 102,010 | 106,867 | 85,008 | 99,311 | 99,311 | 99,311 | 99,311 | 99,311 | 1,214,400 |
| | e. 0502040 Hydrated Lime Expense | | | 392,243 | 367,696 | 263,483 | 371,906 | 391,298 | 394,918 | 404,935 | 401,472 | 407,628 | 416,522 | 356,548 | 405,595 | 4,574,245 |
| | f. 0502300 Caustic Expense | | | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 300,000 |
| 7 | Net Expense (C) | | | 1,421,824 | 1,336,488 | 1,001,927 | 1,382,142 | 1,426,980 | 1,465,949 | 1,456,055 | 1,483,137 | 1,483,419 | 1,514,175 | 1,311,791 | 1,499,939 | 16,783,826 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | | $1,431,194 | $1,345,858 | $1,011,298 | $1,391,513 | $1,436,350 | $1,475,319 | $1,465,425 | $1,492,507 | $1,492,790 | $1,523,545 | $1,321,161 | $1,509,309 | $16,896,268 |
| | a. Recoverable Costs Allocated to Energy | | | 1,431,194 | 1,345,858 | 1,011,298 | 1,391,513 | 1,436,350 | 1,475,319 | 1,465,425 | 1,492,507 | 1,492,790 | 1,523,545 | 1,321,161 | 1,509,309 | 16,896,268 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | 1,400,082 | 1,314,159 | 994,353 | 1,360,849 | 1,396,157 | 1,431,917 | 1,417,906 | 1,440,318 | 1,442,847 | 1,473,276 | 1,277,119 | 1,474,184 | 16,423,168 |
| 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) | | | $ 1,400,082 | $ 1,314,159 | $ 994,353 | $ 1,360,849 | $ 1,396,157 | $ 1,431,917 | $ 1,417,906 | $ 1,440,318 | $ 1,442,847 | $ 1,473,276 | $ 1,277,119 | $ 1,474,184 | $ 16,423,168 |

Notes:

(A) Line 3 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $150 | $150 | $150 | $150 | $150 | $0 | $0 | $0 | $750 |
| | b. Clearings to Plant | | 300 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 750 | 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 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 12,374 | 12,374 | 12,374 | 12,374 | |
| 3 | Less: Accumulated Depreciation | (2,655) | (2,684) | (2,714) | (2,744) | (2,774) | (2,804) | (2,834) | (2,864) | (2,894) | (2,924) | (2,956) | (2,988) | (3,020) | |
| 4 | CWIP - Non-Interest Bearing | 300 | 0 | 0 | 0 | 0 | 150 | 300 | 450 | 600 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $8,969 | $8,940 | $8,910 | $8,880 | $8,850 | $8,970 | $9,090 | $9,210 | $9,330 | $9,450 | $9,418 | $9,386 | $9,354 | |
| 6 | Average Net Investment | | $8,954 | $8,925 | $8,895 | $8,865 | $8,910 | $9,030 | $9,150 | $9,270 | $9,390 | $9,434 | $9,402 | $9,370 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component 2.03% | | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 16 | 16 | 16 | 16 | 16 | 185 |
| | b. Equity Component Grossed Up For Taxes 8.33% | | 62 | 62 | 62 | 62 | 62 | 63 | 64 | 64 | 65 | 66 | 65 | 65 | 762 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) 3.0658% | | 29 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 32 | 32 | 32 | 365 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/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) 0.009035 | | 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) | | $115 | $116 | $116 | $116 | $116 | $117 | $118 | $119 | $120 | $123 | $122 | $122 | 1,420 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $115 | $116 | $116 | $116 | $116 | $117 | $118 | $119 | $120 | $123 | $122 | $122 | 1,420 |
| 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) | | 114 | 115 | 115 | 115 | 115 | 116 | 117 | 118 | 119 | 122 | 121 | 121 | 1,414 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $114 | $115 | $115 | $115 | $115 | $116 | $117 | $118 | $119 | $122 | $121 | $121 | $1,414 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | (35,344) | (35,640) | (35,936) | (36,232) | (36,528) | (36,824) | (37,120) | (37,416) | (37,712) | (38,008) | (38,304) | (38,600) | (38,896) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $133,597 | $133,301 | $133,005 | $132,709 | $132,413 | $132,117 | $131,821 | $131,525 | $131,229 | $130,933 | $130,637 | $130,341 | $130,045 | |
| 6 | Average Net Investment | | | $133,449 | $133,153 | $132,857 | $132,561 | $132,265 | $131,969 | $131,673 | $131,377 | $131,081 | $130,785 | $130,489 | $130,193 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 225 | 225 | 224 | 224 | 223 | 223 | 222 | 222 | 221 | 221 | 220 | 220 | 2,670 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 927 | 925 | 923 | 921 | 919 | 917 | 915 | 913 | 910 | 908 | 906 | 904 | 10,988 |
| | 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) | | | $1,569 | $1,567 | $1,564 | $1,562 | $1,559 | $1,557 | $1,554 | $1,552 | $1,548 | $1,546 | $1,543 | $1,541 | 18,662 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $1,569 | $1,567 | $1,564 | $1,562 | $1,559 | $1,557 | $1,554 | $1,552 | $1,548 | $1,546 | $1,543 | $1,541 | 18,662 |
| 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) | | | 1,457 | 1,456 | 1,453 | 1,451 | 1,448 | 1,446 | 1,443 | 1,442 | 1,438 | 1,436 | 1,433 | 1,431 | 17,334 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $1,457 | $1,456 | $1,453 | $1,451 | $1,448 | $1,446 | $1,443 | $1,442 | $1,438 | $1,436 | $1,433 | $1,431 | $17,334 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | (21,785) | (21,988) | (22,191) | (22,394) | (22,597) | (22,800) | (23,003) | (23,206) | (23,409) | (23,612) | (23,815) | (24,018) | (24,221) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $54,221 | $54,018 | $53,815 | $53,612 | $53,409 | $53,206 | $53,003 | $52,800 | $52,597 | $52,394 | $52,191 | $51,988 | $51,785 | |
| 6 | Average Net Investment | | | $54,120 | $53,917 | $53,714 | $53,511 | $53,308 | $53,105 | $52,902 | $52,699 | $52,496 | $52,293 | $52,090 | $51,887 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 91 | 91 | 91 | 90 | 90 | 90 | 89 | 89 | 89 | 88 | 88 | 88 | 1,074 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 376 | 374 | 373 | 372 | 370 | 369 | 367 | 366 | 365 | 363 | 362 | 360 | 4,417 |
| | 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) | | | $733 | $731 | $730 | $728 | $726 | $725 | $722 | $721 | $720 | $717 | $716 | $714 | 8,683 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $733 | $731 | $730 | $728 | $726 | $725 | $722 | $721 | $720 | $717 | $716 | $714 | 8,683 |
| 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) | | | 533 | 531 | 531 | 529 | 528 | 527 | 525 | 524 | 523 | 521 | 521 | 519 | 6,313 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $533 | $531 | $531 | $529 | $528 | $527 | $525 | $524 | $523 | $521 | $521 | $519 | $6,313 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | |
| 3 | Less: Accumulated Depreciation | | (431,137) | (467,033) | (502,929) | (538,825) | (574,721) | (610,617) | (646,513) | (682,409) | (718,305) | (754,201) | (790,097) | (825,993) | (861,889) | |
| 4 | CWIP - Non-Interest Bearing | | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $12,463,374 | $12,427,478 | $12,391,582 | $12,355,686 | $12,319,790 | $12,283,894 | $12,247,998 | $12,212,102 | $12,176,206 | $12,140,310 | $12,104,414 | $12,068,518 | $12,032,622 | |
| 6 | Average Net Investment | | | $12,445,426 | $12,409,530 | $12,373,634 | $12,337,738 | $12,301,842 | $12,265,946 | $12,230,050 | $12,194,154 | $12,158,258 | $12,122,362 | $12,086,466 | $12,050,570 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 21,014 | 20,953 | 20,893 | 20,832 | 20,772 | 20,711 | 20,650 | 20,590 | 20,529 | 20,469 | 20,408 | 20,347 | 248,168 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 86,443 | 86,193 | 85,944 | 85,695 | 85,445 | 85,196 | 84,947 | 84,697 | 84,448 | 84,199 | 83,949 | 83,700 | 1,020,856 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.3333% | | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 430,752 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (D) | 0.009890 | | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 127,800 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $154,003 | $153,692 | $153,383 | $153,073 | $152,763 | $152,453 | $152,143 | $151,833 | $151,523 | $151,214 | $150,903 | $150,593 | 1,827,576 |
| | 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 | | | $154,003 | $153,692 | $153,383 | $153,073 | $152,763 | $152,453 | $152,143 | $151,833 | $151,523 | $151,214 | $150,903 | $150,593 | 1,827,576 |
| 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 - 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) | | | 111,965 | 111,739 | 111,514 | 111,289 | 111,063 | 110,838 | 110,613 | 110,387 | 110,162 | 109,937 | 109,711 | 109,486 | 1,328,703 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $111,965 | $111,739 | $111,514 | $111,289 | $111,063 | $110,838 | $110,613 | $110,387 | $110,162 | $109,937 | $109,711 | $109,486 | $1,328,703 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 1
(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 2014 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 2016 - December 2016**

Docket No. 150007-EI
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Witness: T. G. Foster
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | |
| 3 | Less: Accumulated Depreciation | | (47,336) | (53,873) | (60,411) | (66,948) | (73,486) | (80,023) | (86,561) | (93,098) | (99,636) | (106,173) | (112,710) | (119,248) | (125,785) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $3,617,607 | $3,611,069 | $3,604,532 | $3,597,994 | $3,591,457 | $3,584,919 | $3,578,382 | $3,571,845 | $3,565,307 | $3,558,770 | $3,552,232 | $3,545,695 | $3,539,157 | |
| 6 | Average Net Investment | | | $3,614,338 | $3,607,801 | $3,601,263 | $3,594,726 | $3,588,188 | $3,581,651 | $3,575,113 | $3,568,576 | $3,562,038 | $3,555,501 | $3,548,963 | $3,542,426 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 6,103 | 6,092 | 6,081 | 6,070 | 6,059 | 6,048 | 6,037 | 6,026 | 6,015 | 6,003 | 5,992 | 5,981 | 72,507 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 25,104 | 25,059 | 25,013 | 24,968 | 24,923 | 24,877 | 24,832 | 24,786 | 24,741 | 24,696 | 24,650 | 24,605 | 298,254 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | Blended | | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 78,449 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 6,241 |
| | 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) | | | $37,668 | $37,612 | $37,555 | $37,499 | $37,443 | $37,386 | $37,330 | $37,273 | $37,217 | $37,160 | $37,103 | $37,047 | 448,291 |
| | a. Recoverable Costs Allocated to Energy | | | 37,668 | 37,612 | 37,555 | 37,499 | 37,443 | 37,386 | 37,330 | 37,273 | 37,217 | 37,160 | 37,103 | 37,047 | 448,291 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $36,849 | $36,726 | $36,926 | $36,673 | $36,395 | $36,286 | $36,119 | $35,970 | $35,972 | $35,934 | $35,866 | $36,185 | $435,901 |
| 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) | | | $36,849 | $36,726 | $36,926 | $36,673 | $36,395 | $36,286 | $36,119 | $35,970 | $35,972 | $35,934 | $35,866 | $36,185 | $435,901 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | |
| 3 | Less: Accumulated Depreciation | | (5,824,679) | (6,068,599) | (6,312,519) | (6,556,439) | (6,800,359) | (7,044,279) | (7,288,199) | (7,532,119) | (7,776,039) | (8,019,959) | (8,263,879) | (8,507,799) | (8,751,719) | |
| 4 | CWIP - AFUDC Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $128,925,596 | $128,681,676 | $128,437,756 | $128,193,836 | $127,949,916 | $127,705,996 | $127,462,076 | $127,218,156 | $126,974,236 | $126,730,316 | $126,486,396 | $126,242,476 | $125,998,556 | |
| 6 | Average Net Investment | | | $128,803,636 | $128,559,716 | $128,315,796 | $128,071,876 | $127,827,956 | $127,584,036 | $127,340,116 | $127,096,196 | $126,852,276 | $126,608,356 | $126,364,436 | $126,120,516 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 217,485 | 217,073 | 216,661 | 216,249 | 215,838 | 215,426 | 215,014 | 214,602 | 214,190 | 213,778 | 213,366 | 212,954 | 2,582,636 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 894,636 | 892,941 | 891,247 | 889,553 | 887,859 | 886,165 | 884,470 | 882,776 | 881,082 | 879,388 | 877,694 | 875,999 | 10,623,810 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.1722% | | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 2,927,040 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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) | 0.007910 | | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 1,065,876 |
| | 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) | | | $1,430,070 | $1,427,963 | $1,425,857 | $1,423,751 | $1,421,646 | $1,419,540 | $1,417,433 | $1,415,327 | $1,413,221 | $1,411,115 | $1,409,009 | $1,406,902 | 17,021,828 |
| | a. Recoverable Costs Allocated to Energy | | | 1,430,070 | 1,427,963 | 1,425,857 | 1,423,751 | 1,421,646 | 1,419,540 | 1,417,433 | 1,415,327 | 1,413,221 | 1,411,115 | 1,409,009 | 1,406,902 | 17,021,828 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $1,398,982 | $1,394,329 | $1,401,967 | $1,392,377 | $1,381,864 | $1,377,778 | $1,371,470 | $1,365,837 | $1,365,940 | $1,364,555 | $1,362,038 | $1,374,159 | $16,551,296 |
| 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) | | | $1,398,982 | $1,394,329 | $1,401,967 | $1,392,377 | $1,381,864 | $1,377,778 | $1,371,470 | $1,365,837 | $1,365,940 | $1,364,555 | $1,362,038 | $1,374,159 | $16,551,296 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $600,000 | $600,000 | $1,000,000 | $300,000 | $100,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,600,000 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 4,965,495 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | (194,715) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $20,070,225 | 20,070,225 | 20,070,225 | 20,070,225 | 20,070,225 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | |
| 3 | Less: Accumulated Depreciation | | (491,482) | (553,365) | (615,248) | (677,131) | (739,014) | (800,897) | (878,090) | (955,283) | (1,032,476) | (1,109,669) | (1,186,862) | (1,264,055) | (1,341,248) | |
| 4 | CWIP - Non-Interest Bearing | | 2,560,209 | 2,965,495 | 3,565,495 | 4,565,495 | 4,865,495 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $22,138,952 | $22,482,354 | $23,020,471 | $23,958,588 | $24,196,705 | $24,234,822 | $24,157,629 | $24,080,436 | $24,003,243 | $23,926,050 | $23,848,857 | $23,771,664 | $23,694,471 | |
| 6 | Average Net Investment | | | $22,310,653 | $22,751,413 | $23,489,530 | $24,077,647 | $24,215,764 | $24,196,226 | $24,119,033 | $24,041,840 | $23,964,647 | $23,887,454 | $23,810,261 | $23,733,068 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 37,672 | 38,416 | 39,662 | 40,655 | 40,888 | 40,855 | 40,725 | 40,595 | 40,464 | 40,334 | 40,204 | 40,073 | 480,543 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 154,964 | 158,025 | 163,152 | 167,237 | 168,196 | 168,061 | 167,524 | 166,988 | 166,452 | 165,916 | 165,380 | 164,844 | 1,976,739 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.7000% | | 61,883 | 61,883 | 61,883 | 61,883 | 61,883 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 849,766 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | | 2,848 | 2,848 | 2,848 | 2,848 | 2,848 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 39,111 |
| | 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) | | | $246,827 | $250,632 | $257,005 | $262,083 | $263,275 | $279,122 | $278,455 | $277,789 | $277,122 | $276,456 | $275,790 | $275,123 | 3,219,684 |
| | a. Recoverable Costs Allocated to Energy | | | 246,827 | 250,632 | 257,005 | 262,083 | 263,275 | 279,122 | 278,455 | 277,789 | 277,122 | 276,456 | 275,790 | 275,123 | 3,219,684 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $241,462 | $244,729 | $252,699 | $256,308 | $255,908 | $270,911 | $269,426 | $268,076 | $267,851 | $267,335 | $266,597 | $268,720 | $3,130,022 |
| 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) | | | $241,462 | $244,729 | $252,699 | $256,308 | $255,908 | $270,911 | $269,426 | $268,076 | $267,851 | $267,335 | $266,597 | $268,720 | $3,130,022 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Return on Capital Investments, Depreciation and Taxes**
**For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Energy (Project 18)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $150,000 | $150,000 | $3,858,000 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,058,000 | 0 | 1,800,000 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | (1,600,000) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $1,600,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,058,000 | 2,058,000 | 3,858,000 | |
| 3 | Less: Accumulated Depreciation (A) | | (7,204) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (4,236) | (8,472) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 355,800 | 711,600 | 1,067,400 | 1,423,200 | 1,779,000 | 2,134,800 | 2,490,600 | 2,846,400 | 3,202,200 | 1,500,000 | 1,650,000 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $1,592,796 | $355,800 | $711,600 | $1,067,400 | $1,423,200 | $1,779,000 | $2,134,800 | $2,490,600 | $2,846,400 | $3,202,200 | $3,558,000 | $3,703,764 | $3,849,528 | |
| 6 | Average Net Investment | | | $974,298 | $533,700 | $889,500 | $1,245,300 | $1,601,100 | $1,956,900 | $2,312,700 | $2,668,500 | $3,024,300 | $3,380,100 | $3,630,882 | $3,776,646 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 1,645 | 901 | 1,502 | 2,103 | 2,703 | 3,304 | 3,905 | 4,506 | 5,107 | 5,707 | 6,131 | 6,377 | 43,891 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 6,767 | 3,707 | 6,178 | 8,650 | 11,121 | 13,592 | 16,063 | 18,535 | 21,006 | 23,477 | 25,219 | 26,232 | 180,547 |
| | c. Other (A) | | | (56,879) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (56,879) |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.4700% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4,236 | 4,236 | 8,472 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | 292 | 292 | 584 |
| | e. Other (A) | | | (7,700) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (7,700) |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | ($56,167) | $4,608 | $7,680 | $10,753 | $13,824 | $16,896 | $19,968 | $23,041 | $26,113 | $29,184 | $35,878 | $37,137 | 168,915 | |
| | a. Recoverable Costs Allocated to Energy | | (56,167) | 4,608 | 7,680 | 10,753 | 13,824 | 16,896 | 19,968 | 23,041 | 26,113 | 29,184 | 35,878 | 37,137 | 168,915 | |
| | b. Recoverable Costs Allocated to Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | | |
| 11 | Demand Jurisdictional Factor | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | ($54,946) | $4,499 | $7,551 | $10,516 | $13,437 | $16,399 | $19,321 | $22,235 | $25,239 | $28,221 | $34,682 | $36,273 | $163,427 | |
| 13 | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | ($54,946) | $4,499 | $7,551 | $10,516 | $13,437 | $16,399 | $19,321 | $22,235 | $25,239 | $28,221 | $34,682 | $36,273 | $163,427 | |

Notes:

(A) As explained in the testimony of Garry Miller, DEF has revised the permanent dust mitigation in-service date from October 2015 to October 2016 and determined vegetation management compliance can be achived without the 2015 capital investment. As a result, DEF has made these adjustments to ensure that the revenue requirement impact to customers is neutral.
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2nd Qtr end 2015, a total of 260 substation remediations are completed out of 279 slated for clean-up. DEF expects to remediate 3 more substations during the remainder of 2015.

**Project Fiscal Expenditures:**
2015 expenditures are estimated to be $405k lower than originally projected due to remediation work delays at the Consolidated Rock, Holder and Kenneth City substations.

**Project Progress Summary:**
DEF continues to remediate substation sites in accordance with the approved Substation Assessment and Remedial Action Plan (SARAP).

**Project Projections:**
2016 estimated expenditures are $1.1M.

**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:**
As of 2nd Qtr end 2015, there are 3 remaining Transformer Replacement and Inspection Program (TRIP) sites.

**Project Fiscal Expenditures:**
2015 expenditures are estimated to be $42k higher than originally projected due to costs to remove additional impacted soil at the three remaining sites.

**Project Progress Summary:**
This project is on schedule according to the approved Distribution System Investigation, Remediation and Pollution Prevention Program.

**Project Projections:**
2016 estimated expenditures are $3k.

**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) contains 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.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $19k higher than originally projected due to increased costs to comply with PIM regulations. No capital expenditures are estimated for 2015.

**Project Progress Summary:**
Ongoing regulatory compliance activities will continue until pipeline is sold or retired.

**Project Projections:**
2016 estimated O&M expenditures are $696k. No capital expenditures are expected in 2016.

**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 2015.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

**Project Projections:**
No project expenditures are expected in 2016.

**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 is treating its unused NOx costs as a regulatory asset amortizing it over 3 years, as approved by the Commission in Order No. PSC-11-0553-FOF-EI.

**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:**
2015 emission allowance expenditures are estimated to be $1.5M higher than originally projected due to unusable NOx emission allowances as a result of the expiration of the CAIR. CAIR was replaced by the CSAPR on 1/1/15. Consistent with Order No. PSC-11-0553-FOF-EI, DEF is treating costs associated with its unusable CAIR NOx emission allowances as a regulatory asset amortizing it over 3 years, beginning 1/1/15 until fully recovered by 12/31/17, with a return on the unamortized investment.

**Project Progress Summary:**
DEF continually evaluates the status of emission rules to maximize the cost effectiveness of its compliance strategy.

**Project Projections:**
2016 estimated expenditures are $111k. 2016 amortization of the CAIR NOx regulatory asset is approximately $3.6M.

**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.

**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 are under development to ensure compliance with all applicable requirements of the rule.

**Project Fiscal Expenditures:**
2015 project expenditures are estimated to be $43k lower than originally projected as methods used to allocate costs to analyze 316(b) compliance strategies at each affected Duke Energy station were adjusted to reflect present configurations and operations. DEF intends to implement a consistent approach across its entire fleet of regulated units to focus on full compliance with applicable 316(b) requirements through the development of facility specific strategic plans.

**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.

**Project Projections:**
2016 estimated O&M expenditures are $440k. No capital expenditures are expected in 2016.

**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 not 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)

**Project Accomplishments:**
The reclaimed water reuse system project was placed in-service in July 2015. This project will provide DEF with up to 1 1/2 million gallons per day of reclaimed water from the City of Crystal River to supplement well water use. This project has positive environmental impacts as it reduces aquifer use.

**Project Fiscal Expenditures:**
2015 estimated O&M expenditures are estimated to be $661k higher than originally projected due to a $710 decrease in CAIR Crystal River Project 7.4 - Base costs and $1.4 million increase in CAIR Crystal River Project 7.4 - Energy costs. The $710k is due to lower base routine project costs. The $1.4M is due to higher ammonia and hydrated lime costs offset by lower limestone and gypsum costs. 2015 estimated capital expenditures are expected to be $124k higher than originally projected due to a shift in spending from 2014 to 2015 in order to align with the City of Crystal River reclaimed water reuse project timeline.

**Project Progress Summary:**
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program.

**Project Projections:**
2016 estimated O&M and capital expenditures are $34.4M and $713k, 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 2015.

**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 2016.

**Project Title:** **Arsenic Groundwater Standard**
**Project No. 8**

**Project Description:**
On 1/22/01, the EPA adopted a new maximum contaminant level (MCL) for arsenic in drinking water replacing the previous standard of 0.050 mg/L (50ppb) with a new MCL of 0.010 mg/L (10ppb). 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 implications for land application and water reuse projects in Florida because the drinking water standard has been established as the groundwater standard by Rule 62-520.420(1), F.A.C. Lowering the arsenic standard will require new analytical methods for sampling groundwater at numerous DEF sites.

**Project Accomplishments:**
DEF has completed required monitoring as directed by the FDEP.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $23k higher than originally projected due to consultant costs to evaluate the source of arsenic exceedances and issue a summery report in compliance with FDEP Consent Order No. 09-3463C executed on 11/21/11. The Consent Order was issued by the FDEP for exceedance of the arsenic groundwater limit when the EPA lowered the arsenic maximum containment level from 50ppb to 10 ppb.

**Project Progress Summary:**
DEF is evaluating monitoring data and other options to achieve compliance in accordance to Consent Order.

**Project Projections:**
No project expenditures are expected in 2016.

**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:**
2015 capital expenditures are estimated to be $3k lower than originally projected. No new street lighting has been required in Franklin County, the City of Mexico Beach in Bay county or GULF County as DEF is in compliance with sea turtle ordinances. Also, the Don Cesar lighting project is delayed from 2014 to late 4th quarter 2015 due to scheduling conflicts.

**Project Progress Summary:**
DEF is on schedule with activities identified for this program.

**Project Projections:**
2016 estimated project O&M and capital expenditures are $450 and $750, 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

**Project Projections:**
No 2016 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 2015 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 2016 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. 060162-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 2015 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 180MWe 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 2016 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 2015 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 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
The mercury TMDL study concluded in 2012.

**Project Projections:**
No 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA during 2010.

**Project Projections:**
No 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA in September 2010.

**Project Projections:**
No 2016 expenditures are expected for this project.

**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 1/14/11, 2/14/11, 7/18/11,4/7/14 and 11/28/11, respectively. All facilities are required to meet new permitting conditions. In Docket No. 110007-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 thermal studies and whole effluent toxicity testing as required 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.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $54k lower than originally projected due to lower than expected 316(a) thermal study costs at the Anclote and Bartow stations. 2015 capital expenditures are expected to be $86k lower than originally projected due to a vendor reimbursement payment.

**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. DEF continues to work with FDEP to resolve the copper issue at the Suwannee station.

**Project Projections:**
2016 estimated O&M expenditures are $60k. No capital expenditures are expected in 2016.

**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-11-0553-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 the existing FGD and SCR systems as the primary MATS compliance measures. Additional monitoring and emissions reduction technologies will be installed in 2014 & 2015.

**Project Accomplishments:**
DEF installed ORP probes and particulate matter continuous emissions monitoring systems (PM CEMS) in 2014. In addition, a mercury characterization study was performed in late 2014, and temporary mercury re-emission control systems were installed in early 2015. DEF continues to monitor mercury emissions with Appendix K sorbent trap systems.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $153k higher than originally projected due to the addition of a temporary chemical injection system to control mercury emissions, and the cancellation of preliminary engineering for a fuel additive system to improve mercury oxidation. 2015 capital expenditures are expected to be $1.3M higher than originally projected driven by the installation of continuous emission monitoring systems (CEMS) for mercury monitoring, compliance demonstration and feedback to the re-emission control system.

**Project Progress Summary:**
Installation of mercury CEMS and permanent mercury re-emission control systems is scheduled in the third quarter of 2015. Certification and commissioning activities are expected to be completed by the end of the year.

**Project Projections:**
2016 estimated O&M is $529k. No capital expenditures are expected in 2016.

**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-12-0432-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:**
2015 capital expenditures are estimated to be $314k lower than originally projected due to earlier than expected completion of Unit 2 FD fan work in November 2013 versus December 2014. There are no recoverable O&M costs for this project.

**Project Progress Summary:**
This project is in-service.

**Project Projections:**
No 2016 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-14-0173-PAA-EI. DEF will make modifications to the electrostatic precipitators to improve particulate collection efficiency, as well as install reagent injection systems to reduce HCl and mercury emissions.

**Project Accomplishments:**
DEF finalized its CR1&2 MATS Compliance Plan in December 2013 and began implementation in early 2014.

**Project Fiscal Expenditures:**
2015 O&M expenditures are expected to be $51k lower than expected. Capital expenditures are estimated to be $4.2M higher than originally projected due to an additional project related to the Unit 1 electrostatic precipitator (ESP).

**Project Progress Summary:**
Implementation of the CR1&2 MATS Compliance Plan will be completed by April 2016.

**Project Projections:**
2016 estimated O&M and capital expenditures are $3.8M and $2.6M, respectively.

**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:**
DEF began defining and implementing of its CCR Rule compliance strategy.

**Project Fiscal Expenditures:**
2015 estimated O&M and capital expenditures are $391k and $1.6M, respectively.

**Project Progress Summary:**
Ash Landfill: Two engineering firms are studying Crystal River ash landfill stability and ash placement.
Temporary Gypsum Pad: Efforts are underway to address fugitive dust mitigation at the CCR gypsum stack-out.
FGD Blowdown Ponds: A definitive assessment and action plan is being developed.
Emergency Action Plan: A determination if the CCR requires an EPA for the FGD Blowdown Ponds is in process.
Vegetation Mgt & Inspection Work: More frequent mowing and inspection work is planned to comply with the CCR Rule.

**Project Projections:**
2016 estimated O&M and capital expenditures are $1.8M and $3.9M, respectively. See the August 31, 2015 direct testimony of Mr. Miller for 2015 CCR compliance strategy change.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of the Energy & Demand Allocation % by Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) Average 12CP Load Factor at Meter (%) | (2) Sales at Meter (mWh) | (3) Avg 12 CP at Meter (MW) (2)/(8784hrsx(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)/(8784hrs/(4)) | (9) mWh Sales at Source Energy Allocator (%) | (10) 12CP Demand Transmission Allocator (%) | (11) 12CP & 1/13 AD Demand Allocator (%) | (12) NCP Distribution Allocator (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | | | | | |
| **RS-1, RST-1, RSL-1, RSL-2, RSS-1** | | | | | | | | | | | | | |
| Secondary | 0.518 | 19,482,925 | 4,282.48 | 0.401 | 0.9463589 | 20,587,248 | 4,525.22 | 20,587,248 | 5,851.4 | 51.568% | 61.617% | 60.844% | 61.780% |
| **General Service Non-Demand** | | | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | | | |
| Secondary | 0.682 | 1,547,422 | 258.45 | 0.491 | 0.9463589 | 1,635,132 | 273.10 | 1,635,132 | 378.9 | 4.096% | 3.719% | 3.748% | 4.000% |
| Primary | 0.682 | 8,546 | 1.43 | 0.491 | 0.9766343 | 8,750 | 1.46 | 8,750 | 2.0 | 0.022% | 0.020% | 0.020% | 0.021% |
| Transmission | 0.682 | 3,571 | 0.60 | 0.491 | 0.9866343 | 3,619 | 0.60 | 0 | 0.0 | 0.009% | 0.008% | 0.008% | 0.000% |
| | | | | | | | | | | 4.127% | 3.747% | 3.776% | 4.021% |
| **General Service** | | | | | | | | | | | | | |
| **GS-2** Secondary | 1.000 | 161,981 | 18.44 | 1.000 | 0.9463589 | 171,162 | 19.49 | 171,162 | 19.5 | 0.429% | 0.265% | 0.278% | 0.206% |
| **General Service Demand** | | | | | | | | | | | | | |
| **GSD-1, GSDT-1** | | | | | | | | | | | | | |
| Secondary | 0.749 | 11,824,122 | 1,797.93 | 0.594 | 0.9463589 | 12,494,332 | 1,899.84 | 12,494,332 | 2,394.0 | 31.296% | 25.869% | 26.286% | 25.277% |
| Primary | 0.749 | 2,313,813 | 351.83 | 0.594 | 0.9766343 | 2,369,170 | 360.25 | 2,369,170 | 454.0 | 5.934% | 4.905% | 4.984% | 4.793% |
| Secondary Del/ Primary Mtr | 0.749 | 46,245 | 7.03 | 0.594 | 0.9766343 | 47,351 | 7.20 | 47,351 | 9.1 | 0.119% | 0.098% | 0.100% | 0.096% |
| Transm Del/ Primary Mtr | 0.749 | 1,419 | 0.22 | 0.594 | 0.9766343 | 1,453 | 0.22 | 0 | 0.0 | 0.004% | 0.003% | 0.003% | 0.000% |
| Transmission | 0.749 | 0 | 0.00 | 0.594 | 0.9866343 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| **SS-1** Primary | 1.166 | 5,602 | 0.55 | 0.093 | 0.9766343 | 5,736 | 0.56 | 5,736 | 7.0 | 0.014% | 0.008% | 0.008% | 0.074% |
| Transm Del/ Transm Mtr | 1.166 | 11,127 | 1.09 | 0.093 | 0.9866343 | 11,278 | 1.10 | 0 | 0.0 | 0.028% | 0.015% | 0.016% | 0.000% |
| Transm Del/ Primary Mtr | 1.166 | 3,474 | 0.34 | 0.093 | 0.9766343 | 3,557 | 0.35 | 0 | 0.0 | 0.009% | 0.005% | 0.005% | 0.000% |
| | | | | | | | | | | 37.404% | 30.902% | 31.403% | 30.240% |
| **Curtailable** | | | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, SS-3** | | | | | | | | | | | | | |
| Secondary | 1.305 | 0 | 0.00 | 0.456 | 0.9463589 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| Primary | 1.305 | 121,852 | 10.63 | 0.456 | 0.9766343 | 124,767 | 10.88 | 124,767 | 31.2 | 0.313% | 0.148% | 0.161% | 0.329% |
| **SS-3** Primary | 0.583 | 3,604 | 0.70 | 0.077 | 0.9766343 | 3,690 | 0.72 | 3,690 | 5.5 | 0.009% | 0.010% | 0.010% | 0.058% |
| | | | | | | | | | | 0.322% | 0.158% | 0.171% | 0.387% |
| **Interruptible** | | | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2** | | | | | | | | | | | | | |
| Secondary | 1.009 | 88,539 | 9.99 | 0.707 | 0.9463589 | 93,558 | 10.55 | 93,558 | 15.1 | 0.234% | 0.144% | 0.151% | 0.159% |
| Sec Del/Primary Mtr | 1.009 | 4,449 | 0.50 | 0.707 | 0.9766343 | 4,555 | 0.51 | 4,555 | 0.7 | 0.011% | 0.007% | 0.007% | 0.008% |
| Primary Del / Primary Mtr | 1.009 | 1,229,525 | 138.66 | 0.707 | 0.9766343 | 1,258,941 | 141.98 | 1,258,941 | 202.9 | 3.153% | 1.933% | 2.027% | 2.142% |
| Primary Del / Transm Mtr | 1.009 | 9,117 | 1.03 | 0.707 | 0.9866343 | 9,241 | 1.04 | 9,241 | 1.5 | 0.023% | 0.014% | 0.015% | 0.016% |
| Transm Del/ Transm Mtr | 1.009 | 222,224 | 25.06 | 0.707 | 0.9866343 | 225,234 | 25.40 | 0 | 0.0 | 0.564% | 0.346% | 0.363% | 0.000% |
| Transm Del/ Primary Mtr | 1.009 | 269,448 | 30.39 | 0.707 | 0.9766343 | 275,894 | 31.11 | 0 | 0.0 | 0.691% | 0.424% | 0.444% | 0.000% |
| **SS-2** Primary | 0.870 | 9,262 | 1.21 | 0.380 | 0.9766343 | 9,484 | 1.24 | 9,484 | 2.8 | 0.024% | 0.017% | 0.017% | 0.030% |
| Transm Del/ Transm Mtr | 0.870 | 92,038 | 12.05 | 0.380 | 0.9866343 | 93,285 | 12.21 | 0 | 0.0 | 0.234% | 0.166% | 0.171% | 0.000% |
| Transm Del/ Primary Mtr | 0.870 | 80,335 | 10.52 | 0.380 | 0.9766343 | 82,257 | 10.77 | 0 | 0.0 | 0.206% | 0.147% | 0.151% | 0.000% |
| | | | | | | | | | | 5.141% | 3.197% | 3.347% | 2.354% |
| **Lighting** | | | | | | | | | | | | | |
| **LS-1** (Secondary) | 5.506 | 381,551 | 7.89 | 0.479 | 0.9463589 | 403,178 | 8.34 | 403,178 | 95.8 | 1.010% | 0.114% | 0.182% | 1.012% |
| | | 37,922,191 | 6,969.01 | | | 39,922,874 | 7,344.16 | 39,226,296 | 9,471.2 | 100.000% | 100.000% | 100.000% | 100.000% |

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2015
(2) Projected kWh sales for the period January 2016 to December 2016
(3) Calculated: Column 2 / (8,784 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2015
(5) Based on system average line loss analysis for 2014
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,784 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 9 x 1/13 + Column 10 x 12/13
(12) Column 8/ Total Column 8

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) mWh Sales at Source Energy Allocator (%) | (2) 12CP Transmission Demand Allocator (%) | (3) 12CP & 1/13th AD Demand Allocator (%) | (4) NCP Distribution Allocator (%) | (5) Energy-Related Costs ($) | (6) Transmission Demand Costs ($) | (8) Production Demand Costs ($) | (7) Distribution Demand Costs ($) | (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 | 51.568% | 61.617% | 60.844% | 61.780% | $33,378,628 | $480,062 | $2,168,692 | ($164,617) | $35,862,765 | 19,482,925 | **0.184** |
| **General Service Non-Demand** | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 1,547,422 | **0.181** |
| Primary | | | | | | | | | | 8,461 | **0.179** |
| Transmission | | | | | | | | | | 3,500 | **0.177** |
| **TOTAL GS** | 4.127% | 3.747% | 3.776% | 4.021% | $2,671,137 | $29,191 | $134,590 | ($10,715) | $2,824,203 | **1,559,382** | |
| **General Service** | | | | | | | | | | | |
| **GS-2** Secondary | 0.429% | 0.265% | 0.278% | 0.206% | $277,510 | $2,067 | $9,905.12 | ($548.19) | $288,934 | 161,981 | **0.178** |
| **General Service Demand** | | | | | | | | | | | |
| **GSD-1, GSDT-1, SS-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 11,824,122 | **0.180** |
| Primary | | | | | | | | | | 2,346,847 | **0.178** |
| Transmission | | | | | | | | | | 10,904 | **0.176** |
| **TOTAL GSD** | 37.404% | 30.902% | 31.403% | 30.240% | $24,211,054 | $240,764 | $1,119,303 | ($80,575) | $25,490,546 | **14,181,874** | |
| **Curtailable** | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3** | | | | | | | | | | | |
| Secondary | | | | | | | | | | - | **0.173** |
| Primary | | | | | | | | | | 124,201 | **0.171** |
| Transmission | | | | | | | | | | - | **0.170** |
| **TOTAL CS** | 0.322% | 0.158% | 0.171% | 0.387% | $208,271 | $1,231 | $6,081 | ($1,030) | $214,553 | **124,201** | |
| **Interruptible** | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2, SS-2** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 88,539 | **0.175** |
| Primary | | | | | | | | | | 1,577,089 | **0.173** |
| Transmission | | | | | | | | | | 316,911 | **0.172** |
| **TOTAL IS** | 5.141% | 3.197% | 3.347% | 2.354% | $3,327,687 | $24,912 | $119,299 | ($6,274) | $3,465,624 | **1,982,539** | |
| **Lighting** | | | | | | | | | | | |
| **LS-1** Secondary | 1.010% | 0.114% | 0.182% | 1.012% | $653,683 | $884 | $6,503.57 | ($2,695.78) | $658,375 | 381,551 | **0.173** |
| | 100.000% | 100.000% | 100.000% | 100.000% | $64,727,970 | $779,111 | $3,564,373 | ($266,454) | $68,805,000 | 37,874,454 | **0.182** |

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 4 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
(8) Column 3 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 2016 to December 2016
(11) (Column 9/ Column 10)/10

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Capital Structure and Cost Rates**



| Class of Capital | | Retail Amount | Ratio | Cost Rate | Weighted Cost Rate | PreTax Weighted Cost Rate |
|---|---|---|---|---|---|---|
| CE | $ | 4,681,853 | 48.76% | 0.10500 | 5.120% | 8.335% |
| PS | | - | 0.00% | 0.00000 | 0.000% | 0.000% |
| LTD | | 3,672,596 | 38.25% | 0.05187 | 1.984% | 1.984% |
| STD | | (90,568) | -0.94% | 0.00170 | -0.002% | -0.002% |
| CD-Active | | 182,163 | 1.90% | 0.02306 | 0.044% | 0.044% |
| CD-Inactive | | 1,306 | 0.01% | 0.00000 | 0.000% | 0.000% |
| ADIT | | 1,318,615 | 13.73% | 0.00000 | 0.000% | 0.000% |
| FAS 109 | | (164,391) | -1.71% | 0.00000 | 0.000% | 0.000% |
| ITC | | 498 | 0.01% | 0.00000 | 0.000% | 0.000% |
| Total | $ | 9,602,073 | 100.00% | | 7.146% | 10.361% |
| | | | | Total Debt | 2.026% | 2.026% |
| | | | | Total Equity | 5.120% | 8.335% |

May 2015 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Commission Forms 42-1A Through 42-9A**

**January 2014 - December 2014**
**Final True-Up**
**Docket No. 150007-EI**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 10
PARTY: DUKE ENERGY FLORIDA, LLC
(DEF) – (DIRECT)
DESCRIPTION: Thomas G. Foster TGF-1

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**
**(in Dollars)**

Form 42-1A

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)


| Line | | Period Amount |
|---|---|---|
| 1 | Over/(Under) Recovery for the Period January 2014 - December 2014 (Form 42-2A, Line 5 + 6 + 10) | $ 12,764,024 |
| 2 | Estimated/Actual True-Up Amount approved for the period January 2014 - December 2014 (Order No. PSC-14-0643-FOF-EI) | 11,344,981 |
| 3 | Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2016 to December 2016 (Lines 1 - 2) | $ 1,419,043 |

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

**End-of-Period True-Up Amount**
**(in Dollars)**

| Line | Description | | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (net of Revenue Taxes) | | $6,054,777 | $6,743,406 | $5,896,498 | $5,884,006 | $6,810,801 | $7,824,663 | $8,347,610 | $9,289,243 | $8,732,198 | $7,384,114 | $6,641,150 | $6,019,544 | $85,628,010 |
| 2 | True-Up Provision | (19,568,336) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (19,568,336) |
| | (Order No. PSC-13-0606-FOF-EI) | | | | | | | | | | | | | | |
| 3 | ECRC Revenues Applicable to Period (Lines 1 + 2) | | $4,424,082 | 5,112,711 | 4,265,803 | 4,253,312 | 5,180,106 | 6,193,968 | 6,716,915 | 7,658,548 | 7,101,503 | 5,753,419 | 5,010,456 | 4,388,850 | 66,059,674 |
| 4 | Jurisdictional ECRC Costs | | | | | | | | | | | | | | |
| | a. O & M Activities (Form 42-5A, Line 9) | | $2,420,836 | $2,833,207 | $3,929,613 | $4,154,336 | $2,978,741 | $2,927,017 | $3,098,717 | $3,448,643 | $3,675,270 | $3,685,506 | $4,696,078 | $3,647,528 | $41,495,492 |
| | b. Capital Investment Projects (Form 42-7A, Line 9) | | 2,033,067 | 2,064,099 | 2,036,803 | 2,018,418 | 2,007,255 | 2,154,564 | 2,140,476 | 2,155,799 | 2,143,902 | 2,169,591 | 2,194,094 | 2,390,498 | 25,508,565 |
| | c. Other (A) | | 0 | 0 | (14,291,145) | 0 | 586,290 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (13,704,855) |
| | d. Total Jurisdictional ECRC Costs | | $4,453,903 | $4,897,306 | ($8,324,729) | $6,172,754 | $5,572,286 | $5,081,581 | $5,239,193 | $5,604,442 | $5,819,172 | $5,855,097 | $6,890,172 | $6,038,026 | $53,299,202 |
| 5 | Over/(Under) Recovery (Line 3 - Line 4d) | | ($29,820) | $215,405 | $12,590,532 | ($1,919,442) | ($392,180) | $1,112,387 | $1,477,723 | $2,054,106 | $1,282,332 | ($101,677) | ($1,879,716) | ($1,649,176) | $12,760,472 |
| 6 | Interest Provision (Form 42-3A, Line 10) | | (748) | (794) | (312) | 106 | 134 | 211 | 358 | 633 | 831 | 804 | 1,003 | 1,326 | 3,552 |
| 7 | Beginning Balance True-Up & Interest Provision | | (19,568,336) | (17,968,210) | (16,122,904) | (1,901,989) | (2,190,630) | (951,982) | 1,791,311 | 4,900,086 | 8,585,520 | 11,499,377 | 13,029,199 | 12,781,180 | (19,568,336) |
| | a. Deferred True-Up - January 2013 - December 2013 | | | | | | | | | | | | | | |
| | (Order No. PSC-14-0643-FOF-EI) | | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 |
| 8 | True-Up Collected/(Refunded) (see Line 2) | | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 19,568,336 |
| 9 | End of Period Total True-Up (Lines 5+6+7+7a+8) | | ($14,160,212) | ($12,314,906) | $1,906,009 | $1,617,368 | $2,856,016 | $5,599,309 | $8,708,084 | $12,393,518 | $15,307,375 | $16,837,197 | $16,589,178 | $16,572,022 | $16,572,022 |
| 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) | | ($14,160,212) | ($12,314,906) | $1,906,009 | $1,617,368 | $2,856,016 | $5,599,309 | 8,708,084 | $12,393,518 | $15,307,375 | $16,837,197 | $16,589,178 | $16,572,022 | $16,572,022 |

Notes:

(A) Retail portion of the property tax settlement between Citrus County and DEF for assessment years 2012 and 2013.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

**Interest Provision**
**(in Dollars)**

| Line | Description | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10) | ($15,760,338) | ($14,160,212) | ($12,314,906) | $1,906,009 | $1,617,368 | $2,856,016 | $5,599,309 | $8,708,084 | $12,393,518 | $15,307,375 | $16,837,197 | $16,589,178 | |
| 2 | Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5 + 8) | (14,159,464) | (12,314,112) | 1,906,321 | 1,617,262 | 2,855,882 | 5,599,098 | 8,707,726 | 12,392,885 | 15,306,544 | 16,836,393 | 16,588,175 | 16,570,696 | |
| 3 | Total of Beginning & Ending True-Up (Lines 1 + 2) | (29,919,802) | (26,474,323) | (10,408,585) | 3,523,270 | 4,473,250 | 8,455,115 | 14,307,036 | 21,100,969 | 27,700,062 | 32,143,768 | 33,425,371 | 33,159,874 | |
| 4 | Average True-Up Amount (Line 3 x 1/2) | (14,959,901) | (13,237,162) | (5,204,293) | 1,761,635 | 2,236,625 | 4,227,558 | 7,153,518 | 10,550,485 | 13,850,031 | 16,071,884 | 16,712,686 | 16,579,937 | |
| 5 | Interest Rate (Last Business Day of Prior Month) | 0.05% | 0.07% | 0.07% | 0.07% | 0.08% | 0.07% | 0.06% | 0.06% | 0.08% | 0.06% | 0.07% | 0.08% | |
| 6 | Interest Rate (Last Business Day of Current Month) | 0.07% | 0.07% | 0.07% | 0.08% | 0.07% | 0.06% | 0.06% | 0.08% | 0.06% | 0.07% | 0.08% | 0.10% | |
| 7 | Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 0.12% | 0.14% | 0.14% | 0.15% | 0.15% | 0.13% | 0.12% | 0.14% | 0.14% | 0.13% | 0.15% | 0.18% | |
| 8 | Average Interest Rate (Line 7 x 1/2) | 0.060% | 0.070% | 0.070% | 0.075% | 0.075% | 0.065% | 0.060% | 0.070% | 0.070% | 0.065% | 0.075% | 0.090% | |
| 9 | Monthly Average Interest Rate (Line 8 x 1/12) | 0.005% | 0.006% | 0.006% | 0.006% | 0.006% | 0.005% | 0.005% | 0.006% | 0.006% | 0.005% | 0.006% | 0.008% | |
| 10 | Interest Provision for the Month (Line 4 x Line 9) | ($748) | ($794) | ($312) | $106 | $134 | $211 | $358 | $633 | $831 | $804 | $1,003 | $1,326 | $3,552 |

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

**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 | $1,024,282 | $2,151,452 | ($1,127,170) | -52% |
| 1a | Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention | 954,448 | 724,346 | 230,101 | 32% |
| 2 | Distribution System Environmental Investigation, Remediation, and Pollution Prevention | 12,594 | 13,295 | (700) | -5% |
| 3 | Pipeline Integrity Management - Bartow /Anclote Pipeline - Intm | 273,445 | 409,819 | (136,374) | -33% |
| 4 | Above Ground Tank Secondary Containment | 0 | 0 | 0 | 0% |
| 5 | SO2/NOx Emissions Allowances - Energy | 3,656,563 | 3,648,437 | 8,126 | 0% |
| 6 | Phase II Cooling Water Intake 316(b) - Base | 36,656 | 60,000 | (23,344) | -39% |
| 6a | Phase II Cooling Water Intake 316(b) - Intm | 44,774 | 50,000 | (5,226) | -10% |
| 7.2 | CAIR/CAMR - Peaking - Demand | 36,500 | 46,561 | (10,061) | -22% |
| 7.4 | CAIR/CAMR Crystal River - Base | 17,419,034 | 17,534,775 | (115,741) | -1% |
| 7.4 | CAIR/CAMR Crystal River - Energy | 15,021,628 | 14,850,130 | 171,498 | 1% |
| 7.4 | CAIR/CAMR Crystal River - A&G | 149,752 | 144,405 | 5,346 | 4% |
| 7.4 | CAIR/CAMR Crystal River - Conditions of Certification - Energy | 0 | 5,000 | (5,000) | -100% |
| 7.5 | Best Available Retrofit Technology (BART) - Energy | (2,739) | (2,739) | 0 | 0% |
| 8 | Arsenic Groundwater Standard - Base | 10,972 | 9,003 | 1,969 | 22% |
| 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% |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Energy | 494,726 | 468,160 | 26,566 | 6% |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 344,859 | 263,820 | 81,039 | 31% |
| 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 | 4,501,247 | 5,505,221 | (1,003,974) | -18% |
| 2 | Total O&M Activities - Recoverable Costs | $43,978,741 | $45,881,685 | ($1,902,944) | -4% |
| 3 | Recoverable Costs Allocated to Energy | 24,016,284 | 24,738,028 | (721,744) | -3% |
| 4 | Recoverable Costs Allocated to Demand | $19,962,456 | $21,143,656 | ($1,181,200) | -6% |

Notes:

Column (1) - End of Period Totals on Form 42-5A
Column (2) - 2014 Estimated/Actual Filing (7/25/14)
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

**O&M Activities**
**(in Dollars)**

| Line | Description | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | | | | | | | | | | |
| 1 | Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention | $228,560 | $236,063 | $124,670 | $203,335 | $117,206 | $202,220 | $80,462 | ($202,830) | ($52,853) | $40,201 | $167,638 | ($120,390) | $1,024,282 |
| 1a | Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention | 20,954 | 14,449 | (18,394) | 16,582 | 120,397 | (58,800) | 122,125 | 388,549 | 76,147 | 20,525 | 68,015 | 183,897 | 954,448 |
| 2 | Distribution System Environmental Investigation, Remediation, and Pollution Prevention | (5,722) | 16,348 | 2,367 | 16,857 | 0 | (22,757) | 0 | 390 | 3,285 | 253 | 1,574 | 0 | 12,594 |
| 3 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | (32,357) | 26,749 | 46,077 | 9,399 | 29,017 | 8,437 | 54,167 | 20,558 | 30,758 | 36,118 | 18,852 | 25,669 | 273,445 |
| 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 | 324,851 | 254,363 | 295,992 | 268,415 | 388,709 | 354,718 | 455,641 | 380,226 | 310,829 | 207,804 | 204,746 | 210,269 | 3,656,563 |
| 6 | Phase II Cooling Water Intake 316(b) - Base | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 29,180 | (894) | 1,544 | 6,826 | 36,656 |
| 6a | Phase II Cooling Water Intake 316(b) - Intm | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 39,567 | (217) | 4,085 | 1,338 | 44,774 |
| 7.2 | CAIR/CAMR - Peaking | 0 | 0 | 0 | 0 | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 36,500 |
| 7.4 | CAIR/CAMR Crystal River - Base | 1,049,130 | 1,244,280 | 1,831,817 | 1,357,455 | 1,402,382 | 1,484,579 | 1,302,352 | 1,350,262 | 1,558,421 | 1,747,135 | 1,491,445 | 1,599,776 | 17,419,034 |
| 7.4 | CAIR/CAMR Crystal River - Energy | 955,098 | 1,233,157 | 1,629,154 | 1,313,877 | 1,083,923 | 918,319 | 1,094,715 | 1,467,164 | 1,389,245 | 1,387,069 | 1,000,126 | 1,549,783 | 15,021,628 |
| 7.4 | CAIR/CAMR Crystal River - A&G | 7,968 | 16,511 | 10,970 | 7,304 | 12,175 | 17,275 | 18,376 | 20,455 | 16,417 | 10,610 | 3,192 | 8,499 | 149,752 |
| 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 | (2,739) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (2,739) |
| 8 | Arsenic Groundwater Standard - Base | 0 | 11 | 5,093 | 3,899 | 0 | 182 | 0 | 313 | 0 | 285 | 1,071 | 119 | 10,972 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Energy | 31,819 | 71,499 | 18,795 | 37,892 | 47,895 | 9,711 | 36,467 | 37,706 | 45,313 | 54,353 | 22,973 | 80,302 | 494,726 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 0 | 0 | 78,749 | 12,185 | 0 | 10,410 | 38,840 | 26,634 | 6,121 | 0 | (28) | 171,947 | 344,859 |
| 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 | 20,487 | (49,077) | 170,292 | 1,178,247 | (37,460) | 183,231 | 86,476 | 68,531 | 444,123 | 401,723 | 1,975,093 | 59,583 | 4,501,247 |
| 2 | Total of O&M Activities | $2,600,790 | $3,064,353 | $4,192,842 | $4,425,448 | $3,164,245 | $3,144,024 | $3,289,620 | $3,557,958 | $3,896,552 | $3,904,965 | $4,960,326 | $3,777,617 | $43,978,741 |
| 3 | Recoverable Costs Allocated to Energy | 1,332,255 | 1,509,941 | 2,190,243 | 2,810,616 | 1,483,067 | 1,476,388 | 1,712,139 | 1,980,261 | 2,195,631 | 2,050,949 | 3,202,910 | 2,071,883 | 24,016,284 |
| 4 | Recoverable Costs Allocated to Demand - Transm | 228,560 | 236,063 | 124,670 | 203,335 | 117,206 | 202,220 | 80,462 | (202,830) | (52,853) | 40,201 | 167,638 | (120,390) | 1,024,282 |
| | Recoverable Costs Allocated to Demand - Distrib | 15,233 | 30,797 | (16,027) | 33,439 | 120,397 | (81,557) | 122,125 | 388,939 | 79,432 | 20,778 | 69,589 | 183,897 | 967,042 |
| | Recoverable Costs Allocated to Demand - Prod-Base | 1,049,130 | 1,244,291 | 1,836,910 | 1,361,354 | 1,402,382 | 1,484,761 | 1,302,352 | 1,350,575 | 1,587,601 | 1,746,525 | 1,494,060 | 1,606,721 | 17,466,662 |
| | Recoverable Costs Allocated to Demand - Prod-Intm | (32,357) | 26,749 | 46,077 | 9,399 | 29,017 | 8,437 | 54,167 | 20,558 | 70,326 | 35,901 | 22,937 | 27,007 | 318,219 |
| | Recoverable Costs Allocated to Demand - Prod-Peaking | 0 | 0 | 0 | 0 | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 36,500 |
| | Recoverable Costs Allocated to Demand - A&G | 7,968 | 16,511 | 10,970 | 7,304 | 12,175 | 17,275 | 18,376 | 20,455 | 16,417 | 10,610 | 3,192 | 8,499 | 149,752 |
| 5 | Retail Energy Jurisdictional Factor | 0.96590 | 0.95780 | 0.96250 | 0.96070 | 0.97200 | 0.96850 | 0.96630 | 0.96720 | 0.95290 | 0.96460 | 0.96840 | 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) | 1,286,825 | 1,446,222 | 2,108,109 | 2,700,159 | 1,441,542 | 1,429,882 | 1,654,440 | 1,915,309 | 2,092,216 | 1,978,346 | 3,101,698 | 2,028,995 | 23,183,743 |
| 8 | Jurisdictional Demand Recoverable Costs - Transm (B) | 160,456 | 165,724 | 87,522 | 142,747 | 82,282 | 141,964 | 56,487 | (142,393) | (37,105) | 28,222 | 117,687 | (84,517) | 719,076 |
| | Jurisdictional Demand Recoverable Costs - Distrib (B) | 15,166 | 30,662 | (15,957) | 33,293 | 119,869 | (81,199) | 121,589 | 387,231 | 79,083 | 20,686 | 69,284 | 183,090 | 962,797 |
| | Jurisdictional Demand Recoverable Costs - Prod-Base (B) | 974,485 | 1,155,759 | 1,706,214 | 1,264,494 | 1,302,603 | 1,379,120 | 1,209,690 | 1,254,482 | 1,474,643 | 1,622,260 | 1,387,757 | 1,492,403 | 16,223,910 |
| | Jurisdictional Demand Recoverable Costs - Prod-Intm (B) | (23,524) | 19,448 | 33,499 | 6,834 | 21,096 | 6,134 | 39,381 | 14,946 | 51,129 | 26,101 | 16,676 | 19,635 | 231,355 |
| | Jurisdictional Demand Recoverable Costs - Prod-Peaking (B) | 0 | 0 | 0 | 0 | 0 | 35,012 | 0 | 0 | 0 | 0 | 0 | 0 | 35,012 |
| | Jurisdictional Demand Recoverable Costs - A&G (B) | 7,428 | 15,392 | 10,226 | 6,809 | 11,349 | 16,104 | 17,130 | 19,068 | 15,304 | 9,891 | 2,976 | 7,922 | 139,599 |
| 9 | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $2,420,836 | $2,833,207 | $3,929,613 | $4,154,336 | $2,978,741 | $2,927,017 | $3,098,717 | $3,448,643 | $3,675,270 | $3,685,506 | $4,696,078 | $3,647,528 | $41,495,492 |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

**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.x | Pipeline Integrity Management - Bartow/Anclote Pipeline | $292,799 | $292,796 | $3 | 0% |
| 4.x | Above Ground Tank Secondary Containment | 1,845,844 | 1,845,856 | (12) | 0% |
| 5 | SO2/NOx Emissions Allowances | 1,647,877 | 1,649,163 | (1,286) | 0% |
| 7.x | CAIR/CAMR | 749,781 | 752,145 | (2,364) | 0% |
| 7.5 | Best Available Retrofit Technology (BART) | (76) | (76) | 0 | 0% |
| 9 | Sea Turtle - Coastal Street Lighting | 1,390 | 1,390 | 0 | 0% |
| 10.x | Underground Storage Tanks | 29,962 | 29,962 | 0 | 0% |
| 11 | Modular Cooling Towers | 0 | 0 | 0 | 0% |
| 11.1 | Thermal Discharge Permanent Cooling Tower | 6,758,435 | 6,753,271 | 5,164 | 0% |
| 16 | National Pollutant Discharge Elimination System (NPDES) | 959,298 | 976,094 | (16,796) | -2% |
| 17x | Mercury & Air Toxics Standards (MATS) | 14,831,520 | 14,608,145 | 223,375 | 2% |
| 2 | Total Capital Investment Activities - Recoverable Costs | $27,116,830 | $26,908,746 | $208,084 | 1% |
| 3 | Recoverable Costs Allocated to Energy | 16,576,719 | 16,343,342 | $233,377 | 1% |
| 4 | Recoverable Costs Allocated to Demand | $10,540,111 | $10,565,404 | ($25,293) | 0% |

Notes:

Column (1) - End of Period Totals on Form 42-7A
Column (2) - 2014 Estimated/Actual Filing (7/25/14)
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

**Capital Investment Projects-Recoverable Costs**
**(in Dollars)**

Form 42-7A

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)


| Line | Description | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | | | | | | | |
| 3.1 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intermediate | $24,764 | $24,716 | $24,666 | $24,618 | $24,569 | $24,521 | 24,278 | $24,230 | $24,182 | $24,133 | $24,085 | $24,037 | $292,799 |
| 4.1 | Above Ground Tank Secondary Containment - Peaking | 123,359 | 123,072 | 122,783 | 122,496 | 122,209 | 121,920 | 120,727 | 120,443 | 120,158 | 119,874 | 119,589 | 119,305 | 1,455,935 |
| 4.2 | Above Ground Tank Secondary Containment - Base | 30,027 | 29,995 | 29,965 | 29,933 | 29,901 | 29,870 | 29,583 | 29,552 | 29,521 | 29,490 | 29,459 | 29,428 | 356,724 |
| 4.3 | Above Ground Tank Secondary Containment - Intermediate | 2,803 | 2,798 | 2,793 | 2,789 | 2,784 | 2,780 | 2,751 | 2,747 | 2,742 | 2,737 | 2,733 | 2,728 | 33,185 |
| 5 | SO2/NOX Emissions Allowances - Energy | 153,232 | 150,724 | 148,342 | 145,895 | 143,046 | 139,827 | 134,749 | 131,171 | 128,214 | 125,995 | 124,229 | 122,453 | 1,647,877 |
| 7.1 | CAIR/CAMR Anclote- Intermediate | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.2 | CAIR/CAMR - Peaking | 19,548 | 19,517 | 19,487 | 19,456 | 19,425 | 19,395 | 19,199 | 19,169 | 19,138 | 19,108 | 19,077 | 19,047 | 231,566 |
| 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 | 32,641 | 33,582 | 33,507 | 34,200 | 36,047 | 36,099 | 35,815 | 35,872 | 35,052 | 34,218 | 35,971 | 37,813 | 420,817 |
| 7.4 | CAIR/CAMR Crystal River AFUDC - Energy | 3,892 | 6,230 | 6,901 | 7,103 | 8,453 | 8,678 | 8,882 | 9,202 | 9,432 | 9,985 | 9,300 | 9,341 | 97,398 |
| 7.5 | Best Available Retrofit Technology (BART) - Energy | 153 | 155 | 81 | 40 | (505) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (76) |
| 9 | Sea Turtle - Coastal Street Lighting -Distribution | 118 | 117 | 117 | 117 | 117 | 116 | 115 | 115 | 115 | 115 | 114 | 114 | 1,390 |
| 10.1 | Underground Storage Tanks - Base | 1,755 | 1,752 | 1,749 | 1,747 | 1,744 | 1,742 | 1,725 | 1,723 | 1,720 | 1,718 | 1,715 | 1,713 | 20,803 |
| 10.2 | Underground Storage Tanks - Intermediate | 776 | 774 | 772 | 770 | 769 | 767 | 759 | 758 | 756 | 754 | 753 | 751 | 9,159 |
| 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) (B) | 3,642 | 3,617 | 3,590 | 3,564 | 3,538 | 3,512 | 3,480 | 3,454 | 3,428 | 3,402 | 3,377 | 3,351 | 41,950 |
| 11.1 | Crystal River Thermal Discharge Compliance Project - Base (2012) (B) | 584,507 | 600,598 | 596,245 | 591,894 | 559,835 | 553,489 | 548,525 | 544,443 | 540,360 | 536,277 | 532,195 | 528,112 | 6,716,485 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Intermediate | 59,425 | 60,339 | 62,018 | 67,499 | 71,240 | 72,832 | 79,353 | 87,559 | 92,241 | 97,095 | 102,240 | 107,457 | 959,298 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 5,703 | 5,781 | 5,329 | 5,253 | 5,079 | 4,714 | 4,636 | 5,047 | 5,468 | 5,989 | 6,659 | 7,487 | 67,145 |
| 17.1 | Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy | 1,111,804 | 1,138,025 | 1,104,595 | 1,084,526 | 1,082,130 | 1,242,325 | 1,235,958 | 1,247,382 | 1,254,642 | 1,254,731 | 1,254,363 | 1,432,535 | 14,443,010 |
| 17.2 | Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy | 1,686 | 2,160 | 6,474 | 11,900 | 16,533 | 21,003 | 22,958 | 26,969 | 32,409 | 44,187 | 64,716 | 70,370 | 321,365 |
| 2 | Total Investment Projects - Recoverable Costs | $2,159,834 | $2,203,951 | $2,169,413 | $2,153,800 | $2,126,914 | $2,283,589 | $2,273,492 | $2,289,835 | $2,299,578 | $2,309,807 | $2,330,574 | $2,516,042 | $27,116,830 |
| 3 | Recoverable Costs Allocated to Energy | 1,276,469 | 1,303,074 | 1,271,721 | 1,254,717 | 1,254,736 | 1,416,546 | 1,407,182 | 1,419,770 | 1,430,165 | 1,440,886 | 1,459,266 | 1,642,186 | 16,576,719 |
| | Recoverable Costs Allocated to Distribution Demand | 118 | 117 | 117 | 117 | 117 | 116 | 115 | 115 | 115 | 115 | 114 | 114 | 1,390 |
| 4 | Recoverable Costs Allocated to Demand - Production - Base | 68,065 | 68,946 | 68,811 | 69,444 | 71,230 | 71,223 | 70,603 | 70,601 | 69,721 | 68,828 | 70,522 | 72,305 | 840,294 |
| | Recoverable Costs Allocated to Demand - Production - Intermediate | 87,768 | 88,627 | 90,249 | 95,676 | 99,362 | 100,900 | 107,141 | 115,294 | 119,921 | 124,719 | 129,811 | 134,973 | 1,294,441 |
| | Recoverable Costs Allocated to Demand - Production - Peaking | 142,907 | 142,589 | 142,270 | 141,952 | 141,634 | 141,315 | 139,926 | 139,612 | 139,296 | 138,982 | 138,666 | 138,352 | 1,687,501 |
| | Recoverable Costs Allocated to Demand - Production - Base (2012) | 584,507 | 600,598 | 596,245 | 591,894 | 559,835 | 553,489 | 548,525 | 544,443 | 540,360 | 536,277 | 532,195 | 528,112 | 6,716,485 |
| 5 | Retail Energy Jurisdictional Factor | 0.96590 | 0.95780 | 0.96250 | 0.96070 | 0.97200 | 0.96850 | 0.96630 | 0.96720 | 0.95290 | 0.96460 | 0.96840 | 0.97930 | |
| | 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 (C) | 1,232,942 | 1,248,084 | 1,224,032 | 1,205,407 | 1,219,603 | 1,371,925 | 1,359,760 | 1,373,202 | 1,362,804 | 1,389,879 | 1,413,154 | 1,608,193 | 16,008,984 |
| | Jurisdictional Demand Recoverable Costs - Distribution (C) | 117 | 116 | 116 | 116 | 116 | 115 | 114 | 114 | 114 | 114 | 113 | 113 | 1,384 |
| 8 | Jurisdictional Demand Recoverable Costs - Production - Base (D) | 63,222 | 64,040 | 63,915 | 64,503 | 66,162 | 66,155 | 65,579 | 65,577 | 64,760 | 63,930 | 65,504 | 67,160 | 780,507 |
| | Jurisdictional Demand Recoverable Costs - Production - Intermediate (D) | 63,810 | 64,434 | 65,614 | 69,559 | 72,239 | 73,357 | 77,895 | 83,822 | 87,186 | 90,674 | 94,376 | 98,129 | 941,097 |
| | Jurisdictional Demand Recoverable Costs - Production - Peaking (D) | 137,082 | 136,777 | 136,471 | 136,166 | 135,861 | 135,555 | 134,223 | 133,921 | 133,618 | 133,317 | 133,014 | 132,713 | 1,618,718 |
| | Jurisdictional Demand Recoverable Costs - Production - Base (2012) (D) | 535,893 | 550,647 | 546,656 | 542,667 | 513,274 | 507,456 | 502,905 | 499,162 | 495,419 | 491,675 | 487,933 | 484,189 | 6,157,875 |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $2,033,067 | $2,064,099 | $2,036,803 | $2,018,418 | $2,007,255 | $2,154,564 | $2,140,476 | $2,155,799 | $2,143,902 | $2,169,591 | $2,194,094 | $2,390,498 | $25,508,565 |

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) The POD project spend and revenue requirements associated with 2012 and prior activities are jurisdictionalized using the 2012 Production Base Demand separation factor. The revenue requirements associated with the 2013 period and after are jurisdictionalized using the 2013 Production Base Demand separation factor.
(C) Line 3 x Line 5
(D) Line 4 x Line 6

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
Page 9 of 27

**Return on Capital Investments, Depreciation and Taxes**
**For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline - Intermediate (Project 3.1)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions (A) | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 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 | | | $2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | |
| 3 | Less: Accumulated Depreciation | | | (642,049) | (647,693) | (653,337) | (658,981) | (664,625) | (670,269) | (675,913) | (681,557) | (687,201) | (692,845) | (698,489) | (704,133) | (709,777) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $1,972,655 | $1,967,011 | $1,961,367 | $1,955,723 | $1,950,079 | $1,944,435 | $1,938,791 | $1,933,147 | $1,927,503 | $1,921,859 | $1,916,215 | $1,910,571 | $1,904,927 | |
| 6 | Average Net Investment | | | | $1,969,833 | $1,964,189 | $1,958,545 | $1,952,901 | $1,947,257 | $1,941,613 | $1,935,969 | $1,930,325 | $1,924,681 | $1,919,037 | $1,913,393 | $1,907,749 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 3,693 | 3,683 | 3,672 | 3,662 | 3,651 | 3,641 | 3,227 | 3,217 | 3,208 | 3,198 | 3,189 | 3,180 | 41,221 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 13,362 | 13,324 | 13,285 | 13,247 | 13,209 | 13,171 | 13,342 | 13,304 | 13,265 | 13,226 | 13,187 | 13,148 | 159,070 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | | | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 67,728 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/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) | | | | 2,065 | 2,065 | 2,065 | 2,065 | 2,065 | 2,065 | 2,065 | 2,065 | 2,065 | 2,065 | 2,065 | 2,065 | 24,780 |
| | e. Other (A) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $24,764 | $24,716 | $24,666 | $24,618 | $24,569 | $24,521 | $24,278 | $24,230 | $24,182 | $24,133 | $24,085 | $24,037 | 292,799 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $24,764 | $24,716 | $24,666 | $24,618 | $24,569 | $24,521 | $24,278 | $24,230 | $24,182 | $24,133 | $24,085 | $24,037 | 292,799 |
| 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 |
| 13 | Retail Demand-Related Recoverable Costs (F) | | | | 18,004 | 17,969 | 17,933 | 17,898 | 17,862 | 17,828 | 17,651 | 17,616 | 17,581 | 17,545 | 17,511 | 17,476 | 212,874 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $18,004 | $17,969 | $17,933 | $17,898 | $17,862 | $17,828 | $17,651 | $17,616 | $17,581 | $17,545 | $17,511 | $17,476 | $212,874 |

Notes:
(A) N/A
(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2013 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**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
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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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | | | $11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | |
| 3 | Less: Accumulated Depreciation | | | (2,008,479) | (2,041,705) | (2,074,931) | (2,108,157) | (2,141,383) | (2,174,609) | (2,207,835) | (2,241,061) | (2,274,287) | (2,307,513) | (2,340,739) | (2,373,965) | (2,407,191) | |
| 4 | CWIP - Non-Interest Bearing | | | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $9,293,325 | $9,260,099 | $9,226,873 | $9,193,647 | $9,160,421 | $9,127,195 | $9,093,969 | $9,060,743 | $9,027,517 | $8,994,291 | $8,961,065 | $8,927,839 | $8,894,613 | |
| 6 | Average Net Investment | | | | $9,276,712 | $9,243,486 | $9,210,260 | $9,177,034 | $9,143,808 | $9,110,582 | $9,077,356 | $9,044,130 | $9,010,904 | $8,977,678 | $8,944,452 | $8,911,226 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 17,394 | 17,332 | 17,269 | 17,207 | 17,145 | 17,082 | 15,129 | 15,074 | 15,018 | 14,963 | 14,907 | 14,852 | 193,372 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 62,927 | 62,702 | 62,476 | 62,251 | 62,026 | 61,800 | 62,560 | 62,331 | 62,102 | 61,873 | 61,644 | 61,415 | 746,107 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | | | 33,226 | 33,226 | 33,226 | 33,226 | 33,226 | 33,226 | 33,226 | 33,226 | 33,226 | 33,226 | 33,226 | 33,226 | 398,712 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/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) | | | | 9,812 | 9,812 | 9,812 | 9,812 | 9,812 | 9,812 | 9,812 | 9,812 | 9,812 | 9,812 | 9,812 | 9,812 | 117,744 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $123,359 | $123,072 | $122,783 | $122,496 | $122,209 | $121,920 | $120,727 | $120,443 | $120,158 | $119,874 | $119,589 | $119,305 | 1,455,935 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $123,359 | $123,072 | $122,783 | $122,496 | $122,209 | $121,920 | $120,727 | $120,443 | $120,158 | $119,874 | $119,589 | $119,305 | 1,455,935 |
| 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) | | | | 118,331 | 118,056 | 117,778 | 117,503 | 117,228 | 116,951 | 115,806 | 115,534 | 115,260 | 114,988 | 114,715 | 114,442 | 1,396,591 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $118,331 | $118,056 | $117,778 | $117,503 | $117,228 | $116,951 | $115,806 | $115,534 | $115,260 | $114,988 | $114,715 | $114,442 | $1,396,591 |

Notes:

(A) N/A

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2013 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**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
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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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 482,923 | |
| | d. Other (A) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $2,881,962 | 2,881,962 | 2,881,962 | 2,881,962 | 2,881,962 | 2,881,962 | 2,881,962 | 2,881,962 | 2,881,962 | 2,881,962 | 2,881,962 | 2,881,962 | 2,399,039 | |
| 3 | Less: Accumulated Depreciation | | | (302,978) | (306,608) | (310,238) | (313,868) | (317,498) | (321,128) | (324,758) | (328,388) | (332,018) | (335,648) | (339,278) | (342,908) | 136,385 | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | | | $2,578,984 | $2,575,354 | $2,571,724 | $2,568,094 | $2,564,464 | $2,560,834 | $2,557,204 | $2,553,574 | $2,549,944 | $2,546,314 | $2,542,684 | $2,539,054 | $2,535,424 | |
| 6 | Average Net Investment | | | | $2,577,169 | $2,573,539 | $2,569,909 | $2,566,279 | $2,562,649 | $2,559,019 | $2,555,389 | $2,551,759 | $2,548,129 | $2,544,499 | $2,540,869 | $2,537,239 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 4,832 | 4,825 | 4,819 | 4,812 | 4,805 | 4,798 | 4,259 | 4,253 | 4,247 | 4,241 | 4,235 | 4,229 | 54,355 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 17,482 | 17,457 | 17,433 | 17,408 | 17,383 | 17,359 | 17,611 | 17,586 | 17,561 | 17,536 | 17,511 | 17,486 | 209,813 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | | | 3,630 | 3,630 | 3,630 | 3,630 | 3,630 | 3,630 | 3,630 | 3,630 | 3,630 | 3,630 | 3,630 | 3,630 | 43,560 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/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) | | | | 4,083 | 4,083 | 4,083 | 4,083 | 4,083 | 4,083 | 4,083 | 4,083 | 4,083 | 4,083 | 4,083 | 4,083 | 48,996 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $30,027 | $29,995 | $29,965 | $29,933 | $29,901 | $29,870 | $29,583 | $29,552 | $29,521 | $29,490 | $29,459 | $29,428 | 356,724 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $30,027 | $29,995 | $29,965 | $29,933 | $29,901 | $29,870 | $29,583 | $29,552 | $29,521 | $29,490 | $29,459 | $29,428 | 356,724 |
| 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) | | | | 27,891 | 27,861 | 27,833 | 27,803 | 27,774 | 27,745 | 27,478 | 27,449 | 27,421 | 27,392 | 27,363 | 27,334 | 331,343 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $27,891 | $27,861 | $27,833 | $27,803 | $27,774 | $27,745 | $27,478 | $27,449 | $27,421 | $27,392 | $27,363 | $27,334 | $331,343 |

Notes:

(A) N/A

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2013 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**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
Page 12 of 27

**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | | | (47,586) | (48,111) | (48,636) | (49,161) | (49,686) | (50,211) | (50,736) | (51,261) | (51,786) | (52,311) | (52,836) | (53,361) | (53,886) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | | | $242,712 | $242,187 | $241,662 | $241,137 | $240,612 | $240,087 | $239,562 | $239,037 | $238,512 | $237,987 | $237,462 | $236,937 | $236,412 | |
| 6 | Average Net Investment | | | | $242,449 | $241,924 | $241,399 | $240,874 | $240,349 | $239,824 | $239,299 | $238,774 | $238,249 | $237,724 | $237,199 | $236,674 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 455 | 454 | 453 | 452 | 451 | 450 | 399 | 398 | 397 | 396 | 395 | 394 | 5,094 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 1,645 | 1,641 | 1,637 | 1,634 | 1,630 | 1,627 | 1,649 | 1,646 | 1,642 | 1,638 | 1,635 | 1,631 | 19,655 |
| | 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) | | | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 2,136 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $2,803 | $2,798 | $2,793 | $2,789 | $2,784 | $2,780 | $2,751 | $2,747 | $2,742 | $2,737 | $2,733 | $2,728 | 33,185 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $2,803 | $2,798 | $2,793 | $2,789 | $2,784 | $2,780 | $2,751 | $2,747 | $2,742 | $2,737 | $2,733 | $2,728 | 33,185 |
| 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) | | | | 2,038 | 2,034 | 2,031 | 2,028 | 2,024 | 2,021 | 2,000 | 1,997 | 1,994 | 1,990 | 1,987 | 1,983 | 24,126 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $2,038 | $2,034 | $2,031 | $2,028 | $2,024 | $2,021 | $2,000 | $1,997 | $1,994 | $1,990 | $1,987 | $1,983 | $24,126 |

Notes:

(A) N/A

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2013 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**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
Page 13 of 27

**SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | |
| | a. 0158150 $SO_2$ Emission Allowance Inventory | $3,977,178 | $3,934,548 | $3,905,107 | $3,866,130 | $3,833,885 | $3,784,538 | $3,745,574 | $3,665,036 | $3,627,692 | $3,589,192 | $3,603,127 | $3,575,712 | $3,551,712 | $3,551,712 |
| | b. 0254020 Auctioned $SO_2$ Allowance | (571,270) | (543,537) | (515,804) | (488,071) | (460,929) | (433,131) | (405,333) | (377,536) | (349,738) | (321,941) | (294,143) | (266,345) | (238,548) | ($238,548) |
| | c. 0158170 NOx Emission Allowance Inventory | 14,454,118 | 14,144,164 | 13,891,509 | 13,606,761 | 13,342,600 | 12,975,440 | 12,631,888 | 12,228,988 | 11,858,308 | 11,558,182 | 11,308,646 | 11,103,517 | 578,825 | 578,825 |
| | d. Other (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 10,310,625 | 10,310,625 |
| 2 | Total Working Capital | $17,860,026 | $17,535,175 | $17,280,812 | $16,984,820 | $16,715,557 | $16,326,847 | $15,972,129 | $15,516,488 | $15,136,262 | $14,825,433 | $14,617,629 | $14,412,883 | $14,202,614 | $14,202,614 |
| 3 | Average Net Investment | | $17,697,601 | $17,407,994 | $17,132,816 | $16,850,188 | $16,521,202 | $16,149,488 | $15,744,308 | $15,326,375 | $14,980,847 | $14,721,531 | $14,515,256 | $14,307,749 | |
| 4 | Return on Average Net Working Capital Balance (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | 33,183 | 32,640 | 32,124 | 31,594 | 30,977 | 30,280 | 26,241 | 25,544 | 24,968 | 24,536 | 24,192 | 23,846 | 340,125 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | 120,049 | 118,084 | 116,218 | 114,301 | 112,069 | 109,547 | 108,508 | 105,627 | 103,246 | 101,459 | 100,037 | 98,607 | 1,307,752 |
| 5 | Total Return Component (C) | | | $153,232 | $150,724 | $148,342 | $145,895 | $143,046 | $139,827 | $134,749 | $131,171 | $128,214 | $125,995 | $124,229 | $122,453 | 1,647,877 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | |
| | a. 0509030 $SO_2$ Allowance Expense | | $42,630 | $29,441 | $38,976 | $32,245 | $49,347 | $38,964 | $80,538 | $37,344 | $38,500 | ($13,935) | $27,415 | $24,000 | $425,466 |
| | b. 0407426 Amortization Expense | | (27,733) | (27,733) | (27,733) | (27,992) | (27,798) | (27,798) | (27,798) | (27,798) | (27,798) | (27,798) | (27,798) | (27,798) | (333,571) |
| | c. 0509212 NOx Allowance Expense | | 309,954 | 252,655 | 284,748 | 264,161 | 367,160 | 343,552 | 402,900 | 370,680 | 300,126 | 249,536 | 205,129 | 214,066 | 3,564,668 |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Net Expense (D) | | 324,851 | 254,363 | 295,992 | 268,415 | 388,709 | 354,718 | 455,641 | 380,226 | 310,829 | 207,804 | 204,746 | 210,269 | 3,656,563 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | $478,083 | $405,087 | $444,334 | $414,310 | $531,755 | $494,545 | $590,390 | $511,397 | $439,043 | $333,799 | $328,975 | $332,722 | 5,304,440 |
| | a. Recoverable Costs Allocated to Energy | | 478,083 | 405,087 | 444,334 | 414,310 | 531,755 | 494,545 | 590,390 | 511,397 | 439,043 | 333,799 | 328,975 | 332,722 | 5,304,440 |
| | b. Recoverable Costs Allocated to Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 9 | Energy Jurisdictional Factor | | 0.96590 | 0.95780 | 0.96250 | 0.96070 | 0.97200 | 0.96850 | 0.96630 | 0.96720 | 0.95290 | 0.96460 | 0.96840 | 0.97930 | |
| 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) | | $461,781 | $387,992 | $427,671 | $398,027 | $516,866 | $478,967 | $570,494 | $494,623 | $418,364 | $321,982 | $318,579 | $325,835 | 5,121,182 |
| 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) | | $461,781 | $387,992 | $427,671 | $398,027 | $516,866 | $478,967 | $570,494 | $494,623 | $418,364 | $321,982 | $318,579 | $325,835 | $5,121,182 |

Notes:

(A) Transfer of unusable NOx emission allowances to a Regulatory Asset due to expiration of Clean Air Interstate Rule (CAIR) program 12/31/14 replaced by Cross State Air Pollution Rule (CSAPR).

(B) Jan - Jun 2014 Line 3 x 10.39% x 1/12. Jul - Dec 2014 Line 3 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) Line 5 is reported on Capital Schedule

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

(E) Line 8a x Line 9

(F) Line 8b x Line 10

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
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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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | | | $1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | |
| 3 | Less: Accumulated Depreciation | | | (261,216) | (264,766) | (268,316) | (271,866) | (275,416) | (278,966) | (282,516) | (286,066) | (289,616) | (293,166) | (296,716) | (300,266) | (303,816) | |
| 4 | CWIP - Non-Interest Bearing | | | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $1,674,892 | $1,671,342 | $1,667,792 | $1,664,242 | $1,660,692 | $1,657,142 | $1,653,592 | $1,650,042 | $1,646,492 | $1,642,942 | $1,639,392 | $1,635,842 | $1,632,292 | |
| 6 | Average Net Investment | | | | $1,673,117 | $1,669,567 | $1,666,017 | $1,662,467 | $1,658,917 | $1,655,367 | $1,651,817 | $1,648,267 | $1,644,717 | $1,641,167 | $1,637,617 | $1,634,067 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 3,137 | 3,130 | 3,124 | 3,117 | 3,110 | 3,104 | 2,753 | 2,747 | 2,741 | 2,735 | 2,729 | 2,723 | 35,150 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 11,349 | 11,325 | 11,301 | 11,277 | 11,253 | 11,229 | 11,384 | 11,360 | 11,335 | 11,311 | 11,286 | 11,262 | 135,672 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | Varies | | | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 42,600 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/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 | | | 1,512 | 1,512 | 1,512 | 1,512 | 1,512 | 1,512 | 1,512 | 1,512 | 1,512 | 1,512 | 1,512 | 1,512 | 18,144 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $19,548 | $19,517 | $19,487 | $19,456 | $19,425 | $19,395 | $19,199 | $19,169 | $19,138 | $19,108 | $19,077 | $19,047 | 231,566 |
| | 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 | | | | $19,548 | $19,517 | $19,487 | $19,456 | $19,425 | $19,395 | $19,199 | $19,169 | $19,138 | $19,108 | $19,077 | $19,047 | 231,566 |
| 10 | Energy Jurisdictional Factor | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor - Production (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) | | | | 18,751 | 18,721 | 18,693 | 18,663 | 18,633 | 18,604 | 18,416 | 18,388 | 18,358 | 18,329 | 18,299 | 18,271 | 222,127 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $18,751 | $18,721 | $18,693 | $18,663 | $18,633 | $18,604 | $18,416 | $18,388 | $18,358 | $18,329 | $18,299 | $18,271 | $222,127 |

Notes:

(A) N/A

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2013 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**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
Page 15 of 27

**Return on Capital Investments, Depreciation and Taxes**
**For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)**
**(in Dollars)**
**(CAIR Projects NOT in Service by Year End 2013)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions (A) | | | | $240,978 | ($152,223) | $139,043 | $25,561 | $2,722 | $11,637 | $10,042 | $9,589 | $4,319 | $6,030 | $410,015 | $26,796 | $734,510 |
| | b. Clearings to Plant | | | | 0 | (4,484) | 0 | 500,649 | 0 | 5,255 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (B) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (198,980) | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $1,296,349 | 1,296,349 | 1,291,865 | 1,291,865 | 1,792,515 | 1,792,515 | 1,797,770 | 1,797,770 | 1,797,770 | 1,797,770 | 1,797,770 | 1,797,770 | 1,797,770 | |
| 3 | Less: Accumulated Depreciation | | | (11,754) | (13,916) | (16,072) | (18,228) | (20,384) | (23,571) | (26,768) | (29,965) | (33,162) | (36,359) | (39,556) | (42,753) | (45,950) | |
| 4 | CWIP - AFUDC-Interest Bearing | | | 1,969,805 | 2,210,784 | 2,063,044 | 2,202,088 | 1,727,000 | 1,729,722 | 1,736,104 | 1,746,147 | 1,755,735 | 1,561,074 | 1,567,104 | 1,977,119 | 2,003,915 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $3,254,401 | $3,493,217 | $3,338,838 | $3,475,726 | $3,499,131 | $3,498,667 | $3,507,107 | $3,513,952 | $3,520,344 | $3,322,485 | $3,325,318 | $3,732,136 | $3,755,735 | |
| 6 | Average Net Investment | | | | $3,373,809 | $3,416,028 | $3,407,282 | $3,487,428 | $3,498,899 | $3,502,887 | $3,510,529 | $3,517,148 | $3,421,414 | $3,323,902 | $3,528,727 | $3,743,935 | |
| 7 | Return on Average Net Investment (C) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 6,326 | 6,405 | 6,389 | 6,539 | 6,560 | 6,568 | 5,851 | 5,862 | 5,702 | 5,540 | 5,881 | 6,240 | 73,863 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 22,886 | 23,172 | 23,113 | 23,656 | 23,734 | 23,761 | 24,194 | 24,240 | 23,580 | 22,908 | 24,320 | 25,803 | 285,367 |
| | c. Other (F) | | | | (449) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (449) |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | | | 2,162 | 2,156 | 2,156 | 2,156 | 3,187 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 34,196 |
| | 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 (E) | | | | 1,855 | 1,849 | 1,849 | 1,849 | 2,566 | 2,573 | 2,573 | 2,573 | 2,573 | 2,573 | 2,573 | 2,573 | 27,979 |
| | e. Other (F) | | | | (139) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (139) |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $32,641 | $33,582 | $33,507 | $34,200 | $36,047 | $36,099 | $35,815 | $35,872 | $35,052 | $34,218 | $35,971 | $37,813 | 420,817 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $32,641 | $33,582 | $33,507 | $34,200 | $36,047 | $36,099 | $35,815 | $35,872 | $35,052 | $34,218 | $35,971 | $37,813 | 420,817 |
| 10 | Energy Jurisdictional Factor | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor - 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 (G) | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (H) | | | | 30,319 | 31,193 | 31,123 | 31,767 | 33,482 | 33,531 | 33,267 | 33,320 | 32,558 | 31,783 | 33,412 | 35,123 | 390,876 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $30,319 | $31,193 | $31,123 | $31,767 | $33,482 | $33,531 | $33,267 | $33,320 | $32,558 | $31,783 | $33,412 | $35,123 | $390,876 |

Notes:

(A) Credit in 2/14 is for the reversal of a 12/13 accrual that was inadertantly re-accrued in 1/14.
(B) Credit in 9/14 is for CWIP FGD Blowdown Treatment costs moved from capital to O&M.
(C) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).
See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.
(D) 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-10-0131-FOF-EI.
(E) 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 2013 Effective Tax Rate on original cost.
(F) Adjustment for return, depreciation and property taxes on ECRC projects moved to base rates per Order No. PSC-12-0425-PAA-EU.
(G) Line 9a x Line 10
(H) Line 9b x Line 11

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
Page 16 of 27

**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | | |
| | a. 0154401 Ammonia Inventory | | | $6,128 | $69,679 | $428,024 | $236,053 | $413,499 | $405,010 | $438,482 | $452,900 | $478,662 | $443,084 | $406,912 | $224,885 | $358,058 | 358,058 |
| | b. 0154200 Limestone Inventory | | | 353,044 | 470,153 | 471,113 | 458,836 | 532,430 | 601,651 | 559,361 | 624,743 | 594,007 | 688,425 | 794,846 | 746,593 | 853,417 | 853,417 |
| 2 | Total Working Capital | | | $359,173 | 539,833 | 899,136 | 694,889 | 945,929 | 1,006,660 | 997,843 | 1,077,643 | 1,072,669 | 1,131,509 | 1,201,758 | 971,478 | 1,211,475 | 1,211,475 |
| 3 | Average Net Investment | | | | 449,503 | 719,485 | 797,013 | 820,409 | 976,295 | 1,002,252 | 1,037,743 | 1,075,156 | 1,102,089 | 1,166,633 | 1,086,618 | 1,091,477 | |
| 4 | Return on Average Net Working Capital Balance (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 843 | 1,349 | 1,494 | 1,538 | 1,831 | 1,879 | 1,730 | 1,792 | 1,837 | 1,944 | 1,811 | 1,819 | $19,867 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 3,049 | 4,881 | 5,406 | 5,565 | 6,623 | 6,799 | 7,152 | 7,410 | 7,595 | 8,040 | 7,489 | 7,522 | 77,531 |
| 5 | Total Return Component (B) | | | | 3,892 | 6,230 | 6,901 | 7,103 | 8,453 | 8,678 | 8,882 | 9,202 | 9,432 | 9,985 | 9,300 | 9,341 | 97,398 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | | |
| | a. 0502030 Ammonia Expense | | | | 315,899 | 342,922 | 360,510 | 443,152 | 497,468 | 422,227 | 481,803 | 494,795 | 600,129 | 507,282 | 450,673 | 364,003 | 5,280,862 |
| | b. 0502040 Limestone Expense | | | | 358,161 | 347,351 | 342,022 | 482,116 | 409,533 | 402,127 | 385,219 | 515,133 | 396,408 | 456,071 | 286,259 | 411,424 | 4,791,825 |
| | c. 0502050 Dibasic Acid Expense | | | | 0 | 0 | 21,602 | 0 | 0 | 11,868 | 21,602 | 0 | 0 | 0 | 0 | 0 | 55,072 |
| | d. 0502070 Gypsum Disposal/Sale | | | | 35,000 | 298,603 | 654,312 | 19,560 | (158,251) | (289,138) | (114,493) | 56,861 | 82,671 | 72,449 | 56,230 | 514,130 | 1,227,934 |
| | b. 0502040 Hydrated Lime Expense | | | | 234,723 | 244,280 | 229,772 | 357,079 | 321,663 | 343,055 | 316,682 | 381,263 | 310,037 | 340,491 | 195,746 | 248,500 | 3,523,291 |
| | f. 0502300 Caustic Expense | | | | 11,314 | 0 | 20,936 | 11,971 | 13,510 | 28,179 | 3,902 | 19,111 | 0 | 10,775 | 11,217 | 11,726 | 142,643 |
| 7 | Net Expense (C) | | | | 955,098 | 1,233,157 | 1,629,154 | 1,313,877 | 1,083,923 | 918,319 | 1,094,715 | 1,467,164 | 1,389,245 | 1,387,069 | 1,000,126 | 1,549,783 | 15,021,628 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | | | $958,990 | $1,239,386 | $1,636,054 | $1,320,981 | $1,092,376 | $926,996 | $1,103,596 | $1,476,365 | $1,398,677 | $1,397,054 | $1,009,425 | $1,559,124 | $15,119,026 |
| | a. Recoverable Costs Allocated to Energy | | | | 958,990 | 1,239,386 | 1,636,054 | 1,320,981 | 1,092,376 | 926,996 | 1,103,596 | 1,476,365 | 1,398,677 | 1,397,054 | 1,009,425 | 1,559,124 | $15,119,026 |
| | b. Recoverable Costs Allocated to Demand | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | Energy Jurisdictional Factor | | | | 0.96590 | 0.95780 | 0.96250 | 0.96070 | 0.97200 | 0.96850 | 0.96630 | 0.96720 | 0.95290 | 0.96460 | 0.96840 | 0.97930 | |
| 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) | | | | $926,288 | $1,187,084 | $1,574,702 | $1,269,066 | $1,061,790 | $897,796 | $1,066,405 | $1,427,941 | $1,332,799 | $1,347,598 | $977,528 | $1,526,850 | $14,595,848 |
| 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) | | | | $926,288 | $1,187,084 | $1,574,702 | $1,269,066 | $1,061,790 | $897,796 | $1,066,405 | $1,427,941 | $1,332,799 | $1,347,598 | $977,528 | $1,526,850 | $14,595,848 |

Notes:

(A) Jan - Jun 2014 Line 3 x 10.39% x 1/12. Jul - Dec 2014 Line 3 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).
See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: BART (Project 7.5)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $327 | $0 | ($9,363) | $0 | ($3,242) | ($67) | $0 | $0 | $0 | $0 | $0 | $0 | ($12,345) |
| | b. Clearings to Plant | | | | 327 | 0 | (9,363) | 0 | (3,242) | (67) | 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 | | | $12,345 | 12,672 | 12,672 | 3,309 | 3,309 | 67 | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 3 | Less: Accumulated Depreciation | | | (13) | (40) | (67) | (74) | (81) | (81) | 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) | | | $12,332 | $12,632 | $12,605 | $3,235 | $3,228 | ($14) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | |
| 6 | Average Net Investment | | | | $12,482 | $12,618 | $7,920 | $3,231 | $1,607 | ($7) | $0 | $0 | $0 | $0 | $0 | $0 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 23 | 24 | 15 | 6 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 71 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 85 | 86 | 54 | 22 | 11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 258 |
| | c. Other | | | | 0 | 0 | 0 | 0 | (383) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (383) |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.5600% | | | 27 | 27 | 7 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 68 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/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) | 0.017176 | | | 18 | 18 | 5 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 46 |
| | e. Other | | | | 0 | 0 | 0 | 0 | (136) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (136) |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $153 | $155 | $81 | $40 | ($505) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | (76) |
| | a. Recoverable Costs Allocated to Energy | | | | 153 | 155 | 81 | 40 | (505) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (76) |
| | b. Recoverable Costs Allocated to Demand | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.96590 | 0.95780 | 0.96250 | 0.96070 | 0.97200 | 0.96850 | 0.96630 | 0.96720 | 0.95290 | 0.96460 | 0.96840 | 0.97930 | | |
| 11 | Demand Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | | $148 | $148 | $78 | $38 | ($491) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | (78) | |
| 13 | Retail Demand-Related 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 | $148 | $78 | $38 | ($491) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($78) | |

Notes:

(A) N/A

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-10-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2013 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**
**Final True-Up**
**January 2014 - December 2014**



**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | | | (1,959) | (1,988) | (2,017) | (2,046) | (2,075) | (2,104) | (2,133) | (2,162) | (2,191) | (2,220) | (2,249) | (2,278) | (2,307) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $9,365 | $9,336 | $9,307 | $9,278 | $9,249 | $9,220 | $9,191 | $9,162 | $9,133 | $9,104 | $9,075 | $9,046 | $9,017 | |
| 6 | Average Net Investment | | | | $9,350 | $9,321 | $9,292 | $9,263 | $9,234 | $9,205 | $9,176 | $9,147 | $9,118 | $9,089 | $9,060 | $9,031 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 18 | 17 | 17 | 17 | 17 | 17 | 15 | 15 | 15 | 15 | 15 | 15 | 193 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 63 | 63 | 63 | 63 | 63 | 62 | 63 | 63 | 63 | 63 | 62 | 62 | 753 |
| | 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) | 0.008758 | | | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 96 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $118 | $117 | $117 | $117 | $117 | $116 | $115 | $115 | $115 | $115 | $114 | $114 | 1,390 |
| | a. 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 | $117 | $117 | $117 | $117 | $116 | $115 | $115 | $115 | $115 | $114 | $114 | 1,390 |
| 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) | | | | 117 | 116 | 116 | 116 | 116 | 115 | 114 | 114 | 114 | 114 | 113 | 113 | 1,384 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $117 | $116 | $116 | $116 | $116 | $115 | $114 | $114 | $114 | $114 | $113 | $113 | $1,384 |

Notes:

(A) N/A

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-10-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2013 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**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
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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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | | | (28,240) | (28,536) | (28,832) | (29,128) | (29,424) | (29,720) | (30,016) | (30,312) | (30,608) | (30,904) | (31,200) | (31,496) | (31,792) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $140,701 | $140,405 | $140,109 | $139,813 | $139,517 | $139,221 | $138,925 | $138,629 | $138,333 | $138,037 | $137,741 | $137,445 | $137,149 | |
| 6 | Average Net Investment | | | | $140,553 | $140,257 | $139,961 | $139,665 | $139,369 | $139,073 | $138,777 | $138,481 | $138,185 | $137,889 | $137,593 | $137,297 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 264 | 263 | 262 | 262 | 261 | 261 | 231 | 231 | 230 | 230 | 229 | 229 | 2,953 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 953 | 951 | 949 | 947 | 945 | 943 | 956 | 954 | 952 | 950 | 948 | 946 | 11,394 |
| | 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) | 0.017176 | | | 242 | 242 | 242 | 242 | 242 | 242 | 242 | 242 | 242 | 242 | 242 | 242 | 2,904 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,755 | $1,752 | $1,749 | $1,747 | $1,744 | $1,742 | $1,725 | $1,723 | $1,720 | $1,718 | $1,715 | $1,713 | 20,803 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,755 | $1,752 | $1,749 | $1,747 | $1,744 | $1,742 | $1,725 | $1,723 | $1,720 | $1,718 | $1,715 | $1,713 | 20,803 |
| 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) | | | | 1,630 | 1,627 | 1,625 | 1,623 | 1,620 | 1,618 | 1,602 | 1,600 | 1,598 | 1,596 | 1,593 | 1,591 | 19,323 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $1,630 | $1,627 | $1,625 | $1,623 | $1,620 | $1,618 | $1,602 | $1,600 | $1,598 | $1,596 | $1,593 | $1,591 | $19,323 |

Notes:

(A) N/A

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2013 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**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
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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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | | | (16,913) | (17,116) | (17,319) | (17,522) | (17,725) | (17,928) | (18,131) | (18,334) | (18,537) | (18,740) | (18,943) | (19,146) | (19,349) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $59,093 | $58,890 | $58,687 | $58,484 | $58,281 | $58,078 | $57,875 | $57,672 | $57,469 | $57,266 | $57,063 | $56,860 | $56,657 | |
| 6 | Average Net Investment | | | | $58,992 | $58,789 | $58,586 | $58,383 | $58,180 | $57,977 | $57,774 | $57,571 | $57,368 | $57,165 | $56,962 | $56,759 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 111 | 110 | 110 | 109 | 109 | 109 | 96 | 96 | 96 | 95 | 95 | 95 | 1,231 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 400 | 399 | 397 | 396 | 395 | 393 | 398 | 397 | 395 | 394 | 393 | 391 | 4,748 |
| | 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) | 0.009740 | | | 62 | 62 | 62 | 62 | 62 | 62 | 62 | 62 | 62 | 62 | 62 | 62 | 744 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $776 | $774 | $772 | $770 | $769 | $767 | $759 | $758 | $756 | $754 | $753 | $751 | 9,159 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $776 | $774 | $772 | $770 | $769 | $767 | $759 | $758 | $756 | $754 | $753 | $751 | 9,159 |
| 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) | | | | 564 | 563 | 561 | 560 | 559 | 558 | 552 | 551 | 550 | 548 | 547 | 546 | 6,659 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $564 | $563 | $561 | $560 | $559 | $558 | $552 | $551 | $550 | $548 | $547 | $546 | $6,659 |

Notes:

(A) N/A

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2013 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**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: CRYSTAL RIVER THERMAL DISCHARGE COMPLIANCE PROJECT - AFUDC - Base (Project 11.1) - 2012 and Prior Year Spend**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | (512,000) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Regulatory Asset Balance | | | $12,063,056 | 12,063,056 | 11,560,429 | 11,057,801 | 10,555,174 | 9,540,547 | 9,063,519 | 8,586,492 | 8,109,465 | 7,632,437 | 7,155,410 | 6,678,383 | 6,201,355 | |
| 3 | Less: Amortization (B) | | | 0 | (502,627) | (502,627) | (502,627) | (502,627) | (477,027) | (477,027) | (477,027) | (477,027) | (477,027) | (477,027) | (477,027) | (477,027) | |
| 4 | CWIP - AFUDC Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $12,063,056 | $11,560,429 | $11,057,801 | $10,555,174 | $10,052,547 | $9,063,519 | $8,586,492 | $8,109,465 | $7,632,437 | $7,155,410 | $6,678,383 | $6,201,355 | $5,724,328 | |
| 6 | Average Net Investment | | | | $11,811,742 | $11,309,115 | $10,806,488 | $10,303,860 | $9,558,033 | $8,825,006 | $8,347,978 | $7,870,951 | $7,393,924 | $6,916,896 | $6,439,869 | $5,962,842 | |
| 7 | Return on Average Net Investment (C) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 22,147 | 21,205 | 20,262 | 19,320 | 17,921 | 16,547 | 13,913 | 13,118 | 12,323 | 11,528 | 10,733 | 9,938 | 188,955 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 80,123 | 76,714 | 73,304 | 69,895 | 64,835 | 59,863 | 57,533 | 54,246 | 50,958 | 47,670 | 44,383 | 41,095 | 720,619 |
| | c. Other (D) | | | | (20,443) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (20,443) |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization (B) | | | | 502,627 | 502,627 | 502,627 | 502,627 | 477,027 | 477,027 | 477,027 | 477,027 | 477,027 | 477,027 | 477,027 | 477,027 | 5,826,728 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (E) | | | | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 625 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $584,507 | $600,598 | $596,245 | $591,894 | $559,835 | $553,489 | $548,525 | $544,443 | $540,360 | $536,277 | $532,195 | $528,112 | 6,716,485 |
| | a. Recoverable Costs Allocated to Demand (2012) | | | | 584,507 | 600,598 | 596,245 | 591,894 | 559,835 | 553,489 | 548,525 | 544,443 | 540,360 | 536,277 | 532,195 | 528,112 | 6,716,485 |
| | b. Recoverable Costs Allocated to Demand (2013) | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Demand Jurisdictional Factor - Production (Base) (2012) (F) | | | | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | |
| 11 | Demand Jurisdictional Factor - Production (Base) (2013) (F) | | | | 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 Demand-Related Recoverable Costs (2012) (G) | | | | $535,893 | $550,647 | $546,656 | $542,667 | $513,274 | $507,456 | $502,905 | $499,162 | $495,419 | $491,675 | $487,933 | $484,189 | 6,157,875 |
| 13 | Retail Demand-Related Recoverable Costs (2013) (H) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $535,893 | $550,647 | $546,656 | $542,667 | $513,274 | $507,456 | $502,905 | $499,162 | $495,419 | $491,675 | $487,933 | $484,189 | $6,157,875 |

Notes:

(A) [redacted] **REDACTED**

(B) Investment amortized over three years in accordance with Order No. PSC-13-0381-PAA-EI.

(C) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(D) Credit to adjust POD return and property taxes to reflect 2012 separation factor . See (F) below.

(E) Property taxes calculated in CR Thermal Discharge Project 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 2013 Effective Tax Rate on original cost.

(F) The POD project spend and revenue requirements associated with 2012 and prior activities are jurisdictionalized using the 2012 Production Base Demand separation factor.
The revenue requirements associated with the 2013 period and after are jurisdictionalized using the 2013 Production Base Demand separation factor.

(G) Line 9a x Line 10

(H) Line 9b x Line 11

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: CRYSTAL RIVER THERMAL DISCHARGE COMPLIANCE PROJECT - AFUDC - Base (Project 11.1) - Post 2012 Spend**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | Regulatory Asset Balance | | | $72,638 | 72,638 | 69,611 | 66,585 | 63,558 | 60,531 | 57,505 | 54,478 | 51,452 | 48,425 | 45,399 | 42,372 | 39,345 | |
| 3 | Less: Amortization (B) | | | 0 | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | |
| 4 | CWIP - AFUDC Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3) | | | $72,638 | $69,611 | $66,585 | $63,558 | $60,531 | $57,505 | $54,478 | $51,452 | $48,425 | $45,399 | $42,372 | $39,345 | $36,319 | |
| 6 | Average Net Investment | | | | $71,124 | $68,098 | $65,071 | $62,045 | $59,018 | $55,992 | $52,965 | $49,938 | $46,912 | $43,885 | $40,859 | $37,832 | |
| 7 | Return on Average Net Investment (C) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 133 | 128 | 122 | 116 | 111 | 105 | 88 | 83 | 78 | 73 | 68 | 63 | 1,168 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 482 | 462 | 441 | 421 | 400 | 380 | 365 | 344 | 323 | 302 | 282 | 261 | 4,463 |
| | c. Other | | | | 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 (B) | | | | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 36,319 |
| | c. Dismantlement | | | | N/A | N/A | N/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 | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $3,642 | $3,617 | $3,590 | $3,564 | $3,538 | $3,512 | $3,480 | $3,454 | $3,428 | $3,402 | $3,377 | $3,351 | 41,950 |
| | a. Recoverable Costs Allocated to Demand (2012) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand (2013) | | | | $3,642 | $3,617 | $3,590 | $3,564 | $3,538 | $3,512 | $3,480 | $3,454 | $3,428 | $3,402 | $3,377 | $3,351 | 41,950 |
| 10 | Demand Jurisdictional Factor - Production (Base) (2012) (E) | | | | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | |
| 11 | Demand Jurisdictional Factor - Production (Base) (2013) (E) | | | | 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 Demand-Related Recoverable Costs (2012) (F) | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (2013) (G) | | | | 3,382 | 3,359 | 3,334 | 3,310 | 3,286 | 3,262 | 3,232 | 3,208 | 3,184 | 3,160 | 3,136 | 3,112 | 38,965 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $3,382 | $3,359 | $3,334 | $3,310 | $3,286 | $3,262 | $3,232 | $3,208 | $3,184 | $3,160 | $3,136 | $3,112 | $38,965 |

Notes:

(A) N/A

(B) Investment amortized over three years in accordance with Order No. PSC-13-0381-PAA-EI.

(C) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(D) N/A

(E) The POD project spend and revenue requirements associated with 2012 and prior activities are jurisdictionalized using the 2012 Production Base Demand separation factor. The revenue requirements associated with the 2013 period and after are jurisdictionalized using the 2013 Production Base Demand separation factor.

(G) Line 9a x Line 10

(H) Line 9b x Line 11

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
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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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $59,589 | $151,479 | $236,476 | $1,029,592 | ($165,456) | $533,037 | $1,187,182 | $730,385 | $363,510 | $770,920 | $431,415 | $787,586 | $6,115,717 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 12,949,257 | |
| | 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 | 12,949,257 | |
| 3 | Less: Accumulated Depreciation | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | | | 6,833,541 | 6,893,130 | 7,044,610 | 7,281,086 | 8,310,678 | 8,145,223 | 8,678,260 | 9,865,442 | 10,595,827 | 10,959,336 | 11,730,256 | 12,161,671 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $6,833,541 | $6,893,130 | $7,044,610 | $7,281,086 | $8,310,678 | $8,145,223 | $8,678,260 | $9,865,442 | $10,595,827 | $10,959,336 | $11,730,256 | $12,161,671 | $12,949,257 | |
| 6 | Average Net Investment | | | | $6,863,336 | $6,968,870 | $7,162,848 | $7,795,882 | $8,227,951 | $8,411,741 | $9,271,851 | $10,230,634 | $10,777,581 | $11,344,796 | $11,945,964 | $12,555,464 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 12,869 | 13,067 | 13,430 | 14,617 | 15,427 | 15,772 | 15,453 | 17,051 | 17,963 | 18,908 | 19,910 | 20,926 | 195,393 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 46,556 | 47,272 | 48,588 | 52,882 | 55,813 | 57,060 | 63,900 | 70,508 | 74,278 | 78,187 | 82,330 | 86,531 | 763,905 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.3333% | | | 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) | 0.009740 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $59,425 | $60,339 | $62,018 | $67,499 | $71,240 | $72,832 | $79,353 | $87,559 | $92,241 | $97,095 | $102,240 | $107,457 | 959,298 |
| | 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 | | | | $59,425 | $60,339 | $62,018 | $67,499 | $71,240 | $72,832 | $79,353 | $87,559 | $92,241 | $97,095 | $102,240 | $107,457 | 959,298 |
| 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 (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) | | | | 43,204 | 43,868 | 45,089 | 49,074 | 51,794 | 52,951 | 57,692 | 63,658 | 67,062 | 70,591 | 74,332 | 78,124 | 697,438 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $43,204 | $43,868 | $45,089 | $49,074 | $51,794 | $52,951 | $57,692 | $63,658 | $67,062 | $70,591 | $74,332 | $78,124 | $697,438 |

Notes:

(A) N/A

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) N/A

(D) N/A

(E) Line 9a x Line 10

(F) Line 9b x Line 11

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
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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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $9,825 | $9,272 | ($49,097) | $32,283 | ($71,445) | ($12,093) | $5,289 | $91,512 | $7,596 | $115,175 | $42,003 | $94,007 | $274,327 |
| | b. Clearings to Plant | | | | 0 | 0 | (78,749) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 56,088 | 15,950 | |
| | 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 | | | $270,034 | 270,034 | 270,034 | 191,285 | 191,285 | 191,285 | 191,285 | 191,285 | 191,285 | 191,285 | 191,285 | 247,373 | 263,323 | |
| 3 | Less: Accumulated Depreciation | | | (5,874) | (6,430) | (6,986) | (7,380) | (7,774) | (8,168) | (8,562) | (8,956) | (9,350) | (9,744) | (10,138) | (10,532) | (11,074) | |
| 4 | CWIP - Non-Interest Bearing | | | 280,921 | 290,747 | 300,019 | 329,672 | 361,954 | 290,509 | 278,416 | 283,705 | 375,217 | 382,813 | 497,988 | 483,903 | 561,960 | |
| 5 | Net Investment (Lines 2 + 3 ) | | | $545,082 | $554,351 | $563,067 | $513,577 | $545,465 | $473,626 | $461,139 | $466,034 | $557,152 | $564,354 | $679,135 | $720,744 | $814,209 | |
| 6 | Average Net Investment | | | | $549,717 | $558,709 | $538,322 | $529,521 | $509,546 | $467,383 | $463,586 | $511,593 | $560,753 | $621,744 | $699,939 | $767,477 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 1,031 | 1,048 | 1,009 | 993 | 955 | 876 | 773 | 853 | 935 | 1,036 | 1,167 | 1,279 | 11,955 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 3,729 | 3,790 | 3,652 | 3,592 | 3,456 | 3,170 | 3,195 | 3,526 | 3,865 | 4,285 | 4,824 | 5,289 | 46,373 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | Blended | | | 556 | 556 | 394 | 394 | 394 | 394 | 394 | 394 | 394 | 394 | 394 | 542 | 5,200 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (D) | 0.017176 | | | 387 | 387 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 377 | 3,617 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $5,703 | $5,781 | $5,329 | $5,253 | $5,079 | $4,714 | $4,636 | $5,047 | $5,468 | $5,989 | $6,659 | $7,487 | 67,145 |
| | a. Recoverable Costs Allocated to Energy | | | | 5,703 | 5,781 | 5,329 | 5,253 | 5,079 | 4,714 | 4,636 | 5,047 | 5,468 | 5,989 | 6,659 | 7,487 | 67,145 |
| | b. Recoverable Costs Allocated to Demand | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | | 0.96590 | 0.95780 | 0.96250 | 0.96070 | 0.97200 | 0.96850 | 0.96630 | 0.96720 | 0.95290 | 0.96460 | 0.96840 | 0.97930 | |
| 11 | Demand Jurisdictional Factor | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | | | $5,509 | $5,537 | $5,129 | $5,047 | $4,937 | $4,566 | $4,480 | $4,881 | $5,210 | $5,777 | $6,449 | $7,332 | 64,853 |
| 13 | Retail Demand-Related Recoverable Costs (F) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $5,509 | $5,537 | $5,129 | $5,047 | $4,937 | $4,566 | $4,480 | $4,881 | $5,210 | $5,777 | $6,449 | $7,332 | $64,853 |

Notes:

(A) N/A

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2013 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
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**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $2,783,899 | $3,431,594 | $5,536,702 | $4,185,808 | $3,325,265 | $1,818,219 | $1,403,758 | $1,140,042 | $3,250,758 | $2,721,089 | $2,475,840 | $707,912 | $32,780,887 |
| | b. Clearings to Plant | | | | 6,316,425 | 76,515 | (4,762,963) | 313,835 | 13,906,529 | 828,439 | 470,357 | 1,672,958 | 286,193 | 101,859 | 16,063,388 | 707,911 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other - AFUDC (A) | | | | 200,803 | (23,831) | 18,824 | 58,629 | 17,890 | 20,326 | 24,542 | 30,932 | 38,744 | 48,050 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $98,259,419 | 104,575,845 | 104,652,359 | 99,889,396 | 100,203,231 | 114,109,760 | 114,938,199 | 115,408,556 | 117,081,513 | 117,367,706 | 117,469,565 | 133,532,953 | 134,240,865 | |
| 3 | Less: Accumulated Depreciation | | | (467,047) | (656,347) | (845,785) | (1,026,601) | (1,207,986) | (1,388,784) | (1,596,841) | (1,805,750) | (2,017,687) | (2,230,142) | (2,442,781) | (2,655,695) | (2,898,693) | |
| 4 | CWIP - AFUDC Bearing | | | 2,765,649 | (566,074) | 2,765,174 | 13,083,664 | 17,014,266 | 6,450,893 | 7,460,999 | 8,418,942 | 7,916,958 | 10,920,267 | 13,587,548 | (0) | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | | $97,792,372 | $103,919,497 | $103,806,574 | $98,862,795 | $98,995,245 | $112,720,975 | $113,341,358 | $113,602,805 | $115,063,826 | $115,137,564 | $115,026,784 | $130,877,258 | $131,342,171 | |
| 6 | Average Net Investment | | | | $100,855,935 | $103,863,036 | $101,334,685 | $98,929,020 | $105,858,110 | $113,031,166 | $113,472,081 | $114,333,316 | $115,100,695 | $115,082,174 | $122,952,021 | $131,109,715 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 189,105 | 194,743 | 190,003 | 185,492 | 185,143 | 211,933 | 189,120 | 190,556 | 191,834 | 191,804 | 191,660 | 218,516 | 2,329,909 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 684,140 | 704,538 | 687,388 | 671,069 | 669,807 | 766,729 | 782,035 | 787,971 | 793,259 | 793,132 | 792,540 | 903,592 | 9,036,200 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.1722% | | | 189,300 | 189,438 | 180,816 | 181,385 | 180,798 | 208,057 | 208,909 | 211,937 | 212,455 | 212,639 | 212,914 | 242,998 | 2,431,646 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/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) | 0.007350 | | | 64,053 | 64,100 | 61,182 | 61,374 | 61,176 | 70,400 | 70,688 | 71,712 | 71,888 | 71,950 | 72,043 | 82,223 | 822,789 |
| | 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) | | | | $1,111,804 | $1,138,025 | $1,104,595 | $1,084,526 | $1,082,130 | $1,242,325 | $1,235,958 | $1,247,382 | $1,254,642 | $1,254,731 | $1,254,363 | $1,432,535 | 14,443,010 |
| | a. Recoverable Costs Allocated to Energy | | | | 1,111,804 | 1,138,025 | 1,104,595 | 1,084,526 | 1,082,130 | 1,242,325 | 1,235,958 | 1,247,382 | 1,254,642 | 1,254,731 | 1,254,363 | 1,432,535 | 14,443,010 |
| | b. Recoverable Costs Allocated to Demand | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | | 0.96590 | 0.95780 | 0.96250 | 0.96070 | 0.97200 | 0.96850 | 0.96630 | 0.96720 | 0.95290 | 0.96460 | 0.96840 | 0.97930 | |
| 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) | | | | $1,073,891 | $1,090,000 | $1,063,172 | $1,041,904 | $1,051,830 | $1,203,191 | $1,194,306 | $1,206,467 | $1,195,548 | $1,210,313 | $1,214,725 | $1,402,881 | 13,948,228 |
| 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) | | | | $1,073,891 | $1,090,000 | $1,063,172 | $1,041,904 | $1,051,830 | $1,203,191 | $1,194,306 | $1,206,467 | $1,195,548 | $1,210,313 | $1,214,725 | $1,402,881 | $13,948,228 |

Notes:

(A) AFUDC rate reflected within Docket 130208-EI per Order PSC-13-0598-FOF-EI. (AFUDC Monthly Compound Rate) 0.5995%

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2013 Effective Tax Rate on original cost.

(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.

(F) Line 9a x Line 10

(G) Line 9b x Line 11

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-1)
Page 26 of 27

**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $109,391 | $887,264 | $366,075 | $704,290 | $328,146 | $185,083 | $752,279 | $518,935 | $2,233,518 | ($91,914) | $1,408,908 | $7,401,975 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,608,050 | 44,594 | 1,202,197 | |
| | 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 | | | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,608,050 | 2,652,644 | 3,854,841 | |
| 3 | Less: Accumulated Depreciation | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (8,179) | (16,418) | |
| 4 | CWIP - Non-Interest Bearing | | | 194,715 | 194,715 | 304,106 | 1,191,369 | 1,557,445 | 2,261,735 | 2,589,881 | 2,774,964 | 3,527,243 | 4,046,178 | 3,671,646 | 3,535,137 | 3,741,848 | |
| 5 | Net Investment (Lines 2 + 3 ) | | | $194,715 | $194,715 | $304,106 | $1,191,369 | $1,557,445 | $2,261,735 | $2,589,881 | $2,774,964 | $3,527,243 | $4,046,178 | $6,279,696 | $6,179,603 | $7,580,272 | |
| 6 | Average Net Investment | | | | $194,715 | $249,410 | $747,737 | $1,374,407 | $1,909,590 | $2,425,808 | $2,682,423 | $3,151,104 | $3,786,711 | $5,162,937 | $6,229,649 | $6,879,937 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 365 | 468 | 1,402 | 2,577 | 3,580 | 4,548 | 4,471 | 5,252 | 6,311 | 8,605 | 10,383 | 11,467 | 59,429 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 1,321 | 1,692 | 5,072 | 9,323 | 12,953 | 16,455 | 18,487 | 21,717 | 26,098 | 35,582 | 42,934 | 47,416 | 239,050 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.7000% | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 8,179 | 8,239 | 16,418 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/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) | 0.017176 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,797 | 3,825 | 7,622 |
| | e. Other (E) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (577) | (577) | (1,154) |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,686 | $2,160 | $6,474 | $11,900 | $16,533 | $21,003 | $22,958 | $26,969 | $32,409 | $44,187 | $64,716 | $70,370 | 321,365 |
| | a. Recoverable Costs Allocated to Energy | | | | 1,686 | 2,160 | 6,474 | 11,900 | 16,533 | 21,003 | 22,958 | 26,969 | 32,409 | 44,187 | 64,716 | 70,370 | 321,365 |
| | b. Recoverable Costs Allocated to Demand | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | | 0.96590 | 0.95780 | 0.96250 | 0.96070 | 0.97200 | 0.96850 | 0.96630 | 0.96720 | 0.95290 | 0.96460 | 0.96840 | 0.97930 | |
| 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) | | | | $1,629 | $2,069 | $6,231 | $11,432 | $16,070 | $20,341 | $22,184 | $26,084 | $30,883 | $42,623 | $62,671 | $68,913 | 311,131 |
| 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) | | | | $1,629 | $2,069 | $6,231 | $11,432 | $16,070 | $20,341 | $22,184 | $26,084 | $30,883 | $42,623 | $62,671 | $68,913 | $311,131 |

Notes:

(A) N/A

(B) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2013 Effective Tax Rate on original cost.

(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.

(F) Line 9a x Line 10

(G) Line 9b x Line 11

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

**Capital Structure and Cost Rates**

| Class of Capital | Retail Amount | Ratio | Cost Rate | Weighted Cost Rate | PreTax Weighted Cost Rate |
|---|---|---|---|---|---|
| CE | $ 3,951,603 | 47.50% | 0.10500 | 4.990% | 8.124% |
| PS | 17,874 | 0.21% | 0.04488 | 0.010% | 0.016% |
| LTD | 3,223,164 | 38.75% | 0.05610 | 2.170% | 2.170% |
| STD | 35,074 | 0.42% | 0.01220 | 0.010% | 0.010% |
| CD-Active | 182,636 | 2.20% | 0.03210 | 0.070% | 0.070% |
| CD-Inactive | 1,162 | 0.01% | 0.00000 | 0.000% | 0.000% |
| ADIT | 1,059,780 | 12.74% | 0.00000 | 0.000% | 0.000% |
| FAS 109 | (155,042) | -1.86% | 0.00000 | 0.000% | 0.000% |
| ITC | 2,091 | 0.03% | 0.08224 | 0.000% | 0.000% |
| Total | $ 8,318,342 | 100.00% | | 7.250% | 10.390% |
| | | | Total Debt | 2.250% | 2.250% |
| | | | Total Equity | 5.000% | 8.140% |

May 2013 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 | $ 4,101,842 | 48.36% | 0.10500 | 5.080% | 8.270% |
| PS | - | 0.00% | 0.00000 | 0.000% | 0.000% |
| LTD | 3,174,547 | 37.42% | 0.05216 | 1.950% | 1.950% |
| STD | 79,303 | 0.93% | 0.01220 | 0.010% | 0.010% |
| CD-Active | 157,817 | 1.86% | 0.02254 | 0.040% | 0.040% |
| CD-Inactive | 1,181 | 0.01% | 0.00000 | 0.000% | 0.000% |
| ADIT | 1,114,885 | 13.14% | 0.00000 | 0.000% | 0.000% |
| FAS 109 | (148,097) | -1.75% | 0.00000 | 0.000% | 0.000% |
| ITC | 1,246 | 0.01% | 0.00000 | 0.000% | 0.000% |
| Total | $ 8,482,724 | 100.00% | | 7.080% | 10.270% |
| | | | Total Debt | 2.000% | 2.000% |
| | | | Total Equity | 5.080% | 8.270% |

May 2014 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Capital Program Detail**

**January 2014 - December 2014**
**Final True-Up**
**Docket No. 150007-EI**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 11
PARTY: DUKE ENERGY FLORIDA, LLC
(DEF) – (DIRECT)
DESCRIPTION: Thomas G. Foster TGF-2

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | 33,952 | 33,952 | 33,952 | 33,952 | 33,952 | 33,952 | 33,952 | |
| 3 | Less: Accumulated Depreciation | | | (8,065) | (8,118) | (8,171) | (8,224) | (8,277) | (8,330) | (8,383) | (8,436) | (8,489) | (8,542) | (8,595) | (8,648) | (8,701) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $25,888 | $25,835 | $25,782 | $25,729 | $25,676 | $25,623 | $25,570 | $25,517 | $25,464 | $25,411 | $25,358 | $25,305 | $25,252 | |
| 6 | Average Net Investment | | | | 25,861 | 25,808 | 25,755 | 25,702 | 25,649 | 25,596 | 25,543 | 25,490 | 25,437 | 25,384 | 25,331 | 25,278 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 48 | 48 | 48 | 48 | 48 | 48 | 43 | 42 | 42 | 42 | 42 | 42 | 541 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 175 | 175 | 175 | 174 | 174 | 174 | 176 | 176 | 175 | 175 | 175 | 174 | 2,098 |
| | 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 | 53 | 53 | 53 | 53 | 53 | 53 | 636 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.009477 | | | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 324 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $303 | $303 | $303 | $302 | $302 | $302 | $299 | $298 | $297 | $297 | $297 | $296 | $3,599 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $303 | $303 | $303 | $302 | $302 | $302 | $299 | $298 | $297 | $297 | $297 | $296 | $3,599 |

**For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | |
| 3 | Less: Accumulated Depreciation | | | (492,837) | (496,112) | (499,387) | (502,662) | (505,937) | (509,212) | (512,487) | (515,762) | (519,037) | (522,312) | (525,587) | (528,862) | (532,137) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $1,043,435 | $1,040,160 | $1,036,885 | $1,033,610 | $1,030,335 | $1,027,060 | $1,023,785 | $1,020,510 | $1,017,235 | $1,013,960 | $1,010,685 | $1,007,410 | $1,004,135 | |
| 6 | Average Net Investment | | | | 1,041,798 | 1,038,523 | 1,035,248 | 1,031,973 | 1,028,698 | 1,025,423 | 1,022,148 | 1,018,873 | 1,015,598 | 1,012,323 | 1,009,048 | 1,005,773 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 1,953 | 1,947 | 1,941 | 1,935 | 1,929 | 1,923 | 1,704 | 1,698 | 1,693 | 1,687 | 1,682 | 1,676 | 21,768 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 7,067 | 7,045 | 7,022 | 7,000 | 6,978 | 6,956 | 7,045 | 7,022 | 6,999 | 6,977 | 6,954 | 6,932 | 83,997 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 2.5579% | | | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 39,300 |
| | 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 | 0.009477 | | | 1,213 | 1,213 | 1,213 | 1,213 | 1,213 | 1,213 | 1,213 | 1,213 | 1,213 | 1,213 | 1,213 | 1,213 | 14,556 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $13,508 | $13,480 | $13,451 | $13,423 | $13,395 | $13,367 | $13,237 | $13,208 | $13,180 | $13,152 | $13,124 | $13,096 | $159,621 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $13,508 | $13,480 | $13,451 | $13,423 | $13,395 | $13,367 | $13,237 | $13,208 | $13,180 | $13,152 | $13,124 | $13,096 | $159,621 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | |
| 3 | Less: Accumulated Depreciation | | | (131,884) | (133,822) | (135,760) | (137,698) | (139,636) | (141,574) | (143,512) | (145,450) | (147,388) | (149,326) | (151,264) | (153,202) | (155,140) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $777,523 | $775,585 | $773,647 | $771,709 | $769,771 | $767,833 | $765,895 | $763,957 | $762,019 | $760,081 | $758,143 | $756,205 | $754,267 | |
| 6 | Average Net Investment | | | | 776,554 | 774,616 | 772,678 | 770,740 | 768,802 | 766,864 | 764,926 | 762,988 | 761,050 | 759,112 | 757,174 | 755,236 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 1,456 | 1,452 | 1,449 | 1,445 | 1,442 | 1,438 | 1,275 | 1,272 | 1,268 | 1,265 | 1,262 | 1,259 | 16,283 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 5,268 | 5,254 | 5,241 | 5,228 | 5,215 | 5,202 | 5,272 | 5,258 | 5,245 | 5,232 | 5,218 | 5,205 | 62,838 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 2.5579% | | | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 23,256 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.009477 | | | 718 | 718 | 718 | 718 | 718 | 718 | 718 | 718 | 718 | 718 | 718 | 718 | 8,616 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $9,380 | $9,362 | $9,346 | $9,329 | $9,313 | $9,296 | $9,203 | $9,186 | $9,169 | $9,153 | $9,136 | $9,120 | $110,993 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $9,380 | $9,362 | $9,346 | $9,329 | $9,313 | $9,296 | $9,203 | $9,186 | $9,169 | $9,153 | $9,136 | $9,120 | $110,993 |

**For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | |
| 3 | Less: Accumulated Depreciation | | | (9,264) | (9,642) | (10,020) | (10,398) | (10,776) | (11,154) | (11,532) | (11,910) | (12,288) | (12,666) | (13,044) | (13,422) | (13,800) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $125,810 | $125,432 | $125,054 | $124,676 | $124,298 | $123,920 | $123,542 | $123,164 | $122,786 | $122,408 | $122,030 | $121,652 | $121,274 | |
| 6 | Average Net Investment | | | | 125,621 | 125,243 | 124,865 | 124,487 | 124,109 | 123,731 | 123,353 | 122,975 | 122,597 | 122,219 | 121,841 | 121,463 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 236 | 235 | 234 | 233 | 233 | 232 | 206 | 205 | 204 | 204 | 203 | 202 | 2,627 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 852 | 850 | 847 | 844 | 842 | 839 | 850 | 848 | 845 | 842 | 840 | 837 | 10,136 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 3.3596% | | | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 4,536 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.009477 | | | 107 | 107 | 107 | 107 | 107 | 107 | 107 | 107 | 107 | 107 | 107 | 107 | 1,284 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,573 | $1,570 | $1,566 | $1,562 | $1,560 | $1,556 | $1,541 | $1,538 | $1,534 | $1,531 | $1,528 | $1,524 | $18,583 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,573 | $1,570 | $1,566 | $1,562 | $1,560 | $1,556 | $1,541 | $1,538 | $1,534 | $1,531 | $1,528 | $1,524 | $18,583 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | |
| 3 | Less: Accumulated Depreciation | | | (281,871) | (287,029) | (292,187) | (297,345) | (302,503) | (307,661) | (312,819) | (317,977) | (323,135) | (328,293) | (333,451) | (338,609) | (343,767) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $1,784,729 | $1,779,571 | $1,774,413 | $1,769,255 | $1,764,097 | $1,758,939 | $1,753,781 | $1,748,623 | $1,743,465 | $1,738,307 | $1,733,149 | $1,727,991 | $1,722,833 | |
| 6 | Average Net Investment | | | | 1,782,150 | 1,776,992 | 1,771,834 | 1,766,676 | 1,761,518 | 1,756,360 | 1,751,202 | 1,746,044 | 1,740,886 | 1,735,728 | 1,730,570 | 1,725,412 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 3,342 | 3,332 | 3,322 | 3,313 | 3,303 | 3,293 | 2,919 | 2,910 | 2,901 | 2,893 | 2,884 | 2,876 | 37,288 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 12,089 | 12,054 | 12,019 | 11,984 | 11,949 | 11,914 | 12,069 | 12,034 | 11,998 | 11,962 | 11,927 | 11,891 | 143,890 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | Blended | | | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 61,896 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.011610 | | | 1,999 | 1,999 | 1,999 | 1,999 | 1,999 | 1,999 | 1,999 | 1,999 | 1,999 | 1,999 | 1,999 | 1,999 | 23,988 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $22,588 | $22,543 | $22,498 | $22,454 | $22,409 | $22,364 | $22,145 | $22,101 | $22,056 | $22,012 | $21,968 | $21,924 | $267,062 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $22,588 | $22,543 | $22,498 | $22,454 | $22,409 | $22,364 | $22,145 | $22,101 | $22,056 | $22,012 | $21,968 | $21,924 | $267,062 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (204,111) | (207,796) | (211,481) | (215,166) | (218,851) | (222,536) | (226,221) | (229,906) | (233,591) | (237,276) | (240,961) | (244,646) | (248,331) | |
| 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) | | | $1,269,690 | $1,266,005 | $1,262,320 | $1,258,635 | $1,254,950 | $1,251,265 | $1,247,580 | $1,243,895 | $1,240,210 | $1,236,525 | $1,232,840 | $1,229,155 | $1,225,470 | |
| 6 | Average Net Investment | | | | 1,267,847 | 1,264,162 | 1,260,477 | 1,256,792 | 1,253,107 | 1,249,422 | 1,245,737 | 1,242,052 | 1,238,367 | 1,234,682 | 1,230,997 | 1,227,312 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 2,377 | 2,370 | 2,363 | 2,356 | 2,350 | 2,343 | 2,076 | 2,070 | 2,064 | 2,058 | 2,052 | 2,046 | 26,525 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 8,600 | 8,575 | 8,550 | 8,525 | 8,500 | 8,475 | 8,585 | 8,560 | 8,535 | 8,509 | 8,484 | 8,458 | 102,356 |
| | 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 | 0.009740 | | | 1,196 | 1,196 | 1,196 | 1,196 | 1,196 | 1,196 | 1,196 | 1,196 | 1,196 | 1,196 | 1,196 | 1,196 | 14,352 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $15,858 | $15,826 | $15,794 | $15,762 | $15,731 | $15,699 | $15,542 | $15,511 | $15,480 | $15,448 | $15,417 | $15,385 | $187,453 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $15,858 | $15,826 | $15,794 | $15,762 | $15,731 | $15,699 | $15,542 | $15,511 | $15,480 | $15,448 | $15,417 | $15,385 | $187,453 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (614,795) | (623,934) | (633,073) | (642,212) | (651,351) | (660,490) | (669,629) | (678,768) | (687,907) | (697,046) | (706,185) | (715,324) | (724,463) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $1,046,869 | $1,037,730 | $1,028,591 | $1,019,452 | $1,010,313 | $1,001,174 | $992,035 | $982,896 | $973,757 | $964,618 | $955,479 | $946,340 | $937,201 | |
| 6 | Average Net Investment | | | | 1,042,300 | 1,033,161 | 1,024,022 | 1,014,883 | 1,005,744 | 996,605 | 987,466 | 978,327 | 969,188 | 960,049 | 950,910 | 941,771 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 1,954 | 1,937 | 1,920 | 1,903 | 1,886 | 1,869 | 1,646 | 1,631 | 1,615 | 1,600 | 1,585 | 1,570 | 21,116 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 7,070 | 7,008 | 6,946 | 6,884 | 6,822 | 6,760 | 6,805 | 6,743 | 6,680 | 6,617 | 6,554 | 6,491 | 81,380 |
| | 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 | 0.008850 | | | 1,225 | 1,225 | 1,225 | 1,225 | 1,225 | 1,225 | 1,225 | 1,225 | 1,225 | 1,225 | 1,225 | 1,225 | 14,700 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $19,388 | $19,309 | $19,230 | $19,151 | $19,072 | $18,993 | $18,815 | $18,738 | $18,659 | $18,581 | $18,503 | $18,425 | $226,864 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $19,388 | $19,309 | $19,230 | $19,151 | $19,072 | $18,993 | $18,815 | $18,738 | $18,659 | $18,581 | $18,503 | $18,425 | $226,864 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (55,529) | (56,245) | (56,961) | (57,677) | (58,393) | (59,109) | (59,825) | (60,541) | (61,257) | (61,973) | (62,689) | (63,405) | (64,121) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $123,409 | $122,693 | $121,977 | $121,261 | $120,545 | $119,829 | $119,113 | $118,397 | $117,681 | $116,965 | $116,249 | $115,533 | $114,817 | |
| 6 | Average Net Investment | | | | 123,051 | 122,335 | 121,619 | 120,903 | 120,187 | 119,471 | 118,755 | 118,039 | 117,323 | 116,607 | 115,891 | 115,175 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 231 | 229 | 228 | 227 | 225 | 224 | 198 | 197 | 196 | 194 | 193 | 192 | 2,534 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 835 | 830 | 825 | 820 | 815 | 810 | 818 | 814 | 809 | 804 | 799 | 794 | 9,773 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 4.8000% | | | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 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 | 0.008250 | | | 123 | 123 | 123 | 123 | 123 | 123 | 123 | 123 | 123 | 123 | 123 | 123 | 1,476 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,905 | $1,898 | $1,892 | $1,886 | $1,879 | $1,873 | $1,855 | $1,850 | $1,844 | $1,837 | $1,831 | $1,825 | $22,375 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,905 | $1,898 | $1,892 | $1,886 | $1,879 | $1,873 | $1,855 | $1,850 | $1,844 | $1,837 | $1,831 | $1,825 | $22,375 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (133,148) | (134,970) | (136,792) | (138,614) | (140,436) | (142,258) | (144,080) | (145,902) | (147,724) | (149,546) | (151,368) | (153,190) | (155,012) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $597,147 | $595,325 | $593,503 | $591,681 | $589,859 | $588,037 | $586,215 | $584,393 | $582,571 | $580,749 | $578,927 | $577,105 | $575,283 | |
| 6 | Average Net Investment | | | | 596,236 | 594,414 | 592,592 | 590,770 | 588,948 | 587,126 | 585,304 | 583,482 | 581,660 | 579,838 | 578,016 | 576,194 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 1,118 | 1,115 | 1,111 | 1,108 | 1,104 | 1,101 | 976 | 972 | 969 | 966 | 963 | 960 | 12,463 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 4,044 | 4,032 | 4,020 | 4,007 | 3,995 | 3,983 | 4,034 | 4,021 | 4,009 | 3,996 | 3,984 | 3,971 | 48,096 |
| | 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 | 0.009740 | | | 593 | 593 | 593 | 593 | 593 | 593 | 593 | 593 | 593 | 593 | 593 | 593 | 7,116 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $7,577 | $7,562 | $7,546 | $7,530 | $7,514 | $7,499 | $7,425 | $7,408 | $7,393 | $7,377 | $7,362 | $7,346 | $89,539 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $7,577 | $7,562 | $7,546 | $7,530 | $7,514 | $7,499 | $7,425 | $7,408 | $7,393 | $7,377 | $7,362 | $7,346 | $89,539 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (221,256) | (224,108) | (226,960) | (229,812) | (232,664) | (235,516) | (238,368) | (241,220) | (244,072) | (246,924) | (249,776) | (252,628) | (255,480) | |
| 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) | | | $815,943 | $813,091 | $810,239 | $807,387 | $804,535 | $801,683 | $798,831 | $795,979 | $793,127 | $790,275 | $787,423 | $784,571 | $781,719 | |
| 6 | Average Net Investment | | | | 814,517 | 811,665 | 808,813 | 805,961 | 803,109 | 800,257 | 797,405 | 794,553 | 791,701 | 788,849 | 785,997 | 783,145 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 1,527 | 1,522 | 1,517 | 1,511 | 1,506 | 1,500 | 1,329 | 1,324 | 1,320 | 1,315 | 1,310 | 1,305 | 16,986 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 5,525 | 5,506 | 5,486 | 5,467 | 5,448 | 5,428 | 5,496 | 5,476 | 5,456 | 5,437 | 5,417 | 5,397 | 65,539 |
| | 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 | 0.008210 | | | 710 | 710 | 710 | 710 | 710 | 710 | 710 | 710 | 710 | 710 | 710 | 710 | 8,520 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $10,614 | $10,590 | $10,565 | $10,540 | $10,516 | $10,490 | $10,387 | $10,362 | $10,338 | $10,314 | $10,289 | $10,264 | $125,269 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $10,614 | $10,590 | $10,565 | $10,540 | $10,516 | $10,490 | $10,387 | $10,362 | $10,338 | $10,314 | $10,289 | $10,264 | $125,269 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (351,902) | (359,738) | (367,574) | (375,410) | (383,246) | (391,082) | (398,918) | (406,754) | (414,590) | (422,426) | (430,262) | (438,098) | (445,934) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $3,265,002 | $3,257,166 | $3,249,330 | $3,241,494 | $3,233,658 | $3,225,822 | $3,217,986 | $3,210,150 | $3,202,314 | $3,194,478 | $3,186,642 | $3,178,806 | $3,170,970 | |
| 6 | Average Net Investment | | | | 3,261,084 | 3,253,248 | 3,245,412 | 3,237,576 | 3,229,740 | 3,221,904 | 3,214,068 | 3,206,232 | 3,198,396 | 3,190,560 | 3,182,724 | 3,174,888 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 6,115 | 6,100 | 6,085 | 6,070 | 6,056 | 6,041 | 5,357 | 5,344 | 5,331 | 5,318 | 5,305 | 5,291 | 68,413 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 22,121 | 22,068 | 22,015 | 21,962 | 21,908 | 21,855 | 22,151 | 22,097 | 22,043 | 21,989 | 21,935 | 21,881 | 264,025 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 2.6000% | | | $7,836 | $7,836 | $7,836 | $7,836 | $7,836 | $7,836 | $7,836 | $7,836 | $7,836 | $7,836 | $7,836 | $7,836 | 94,032 |
| | 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 | 0.011610 | | | 3,499 | 3,499 | 3,499 | 3,499 | 3,499 | 3,499 | 3,499 | 3,499 | 3,499 | 3,499 | 3,499 | 3,499 | 41,988 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $39,571 | $39,503 | $39,435 | $39,367 | $39,299 | $39,231 | $38,843 | $38,776 | $38,709 | $38,642 | $38,575 | $38,507 | $468,458 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $39,571 | $39,503 | $39,435 | $39,367 | $39,299 | $39,231 | $38,843 | $38,776 | $38,709 | $38,642 | $38,575 | $38,507 | $468,458 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (48,774) | (49,015) | (49,256) | (49,497) | (49,738) | (49,979) | (50,220) | (50,461) | (50,702) | (50,943) | (51,184) | (51,425) | (51,666) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $92,660 | $92,419 | $92,178 | $91,937 | $91,696 | $91,455 | $91,214 | $90,973 | $90,732 | $90,491 | $90,250 | $90,009 | $89,768 | |
| 6 | Average Net Investment | | | | 92,540 | 92,299 | 92,058 | 91,817 | 91,576 | 91,335 | 91,094 | 90,853 | 90,612 | 90,371 | 90,130 | 89,889 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 174 | 173 | 173 | 172 | 172 | 171 | 152 | 151 | 151 | 151 | 150 | 150 | 1,940 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 628 | 626 | 624 | 623 | 621 | 620 | 628 | 626 | 624 | 623 | 621 | 620 | 7,484 |
| | 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 | 0.012400 | | | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 1,752 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,189 | $1,186 | $1,184 | $1,182 | $1,180 | $1,178 | $1,167 | $1,164 | $1,162 | $1,161 | $1,158 | $1,157 | $14,068 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,189 | $1,186 | $1,184 | $1,182 | $1,180 | $1,178 | $1,167 | $1,164 | $1,162 | $1,161 | $1,158 | $1,157 | $14,068 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (97,092) | (98,869) | (100,646) | (102,423) | (104,200) | (105,977) | (107,754) | (109,531) | (111,308) | (113,085) | (114,862) | (116,639) | (118,416) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $297,876 | $296,099 | $294,322 | $292,545 | $290,768 | $288,991 | $287,214 | $285,437 | $283,660 | $281,883 | $280,106 | $278,329 | $276,552 | |
| 6 | Average Net Investment | | | | 296,987 | 295,210 | 293,433 | 291,656 | 289,879 | 288,102 | 286,325 | 284,548 | 282,771 | 280,994 | 279,217 | 277,440 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 557 | 554 | 550 | 547 | 544 | 540 | 477 | 474 | 471 | 468 | 465 | 462 | 6,109 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 2,015 | 2,003 | 1,990 | 1,978 | 1,966 | 1,954 | 1,973 | 1,961 | 1,949 | 1,937 | 1,924 | 1,912 | 23,562 |
| | 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 | 0.009740 | | | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 3,852 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $4,670 | $4,655 | $4,638 | $4,623 | $4,608 | $4,592 | $4,548 | $4,533 | $4,518 | $4,503 | $4,487 | $4,472 | $54,847 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $4,670 | $4,655 | $4,638 | $4,623 | $4,608 | $4,592 | $4,548 | $4,533 | $4,518 | $4,503 | $4,487 | $4,472 | $54,847 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (13,443) | (13,545) | (13,647) | (13,749) | (13,851) | (13,953) | (14,055) | (14,157) | (14,259) | (14,361) | (14,463) | (14,565) | (14,667) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $19,649 | $19,547 | $19,445 | $19,343 | $19,241 | $19,139 | $19,037 | $18,935 | $18,833 | $18,731 | $18,629 | $18,527 | $18,425 | |
| 6 | Average Net Investment | | | | 19,598 | 19,496 | 19,394 | 19,292 | 19,190 | 19,088 | 18,986 | 18,884 | 18,782 | 18,680 | 18,578 | 18,476 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 37 | 37 | 36 | 36 | 36 | 36 | 32 | 31 | 31 | 31 | 31 | 31 | 405 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 133 | 132 | 132 | 131 | 130 | 129 | 131 | 130 | 129 | 129 | 128 | 127 | 1,561 |
| | 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 | 0.001728 | | | 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) | | | | $277 | $276 | $275 | $274 | $273 | $272 | $270 | $268 | $267 | $267 | $266 | $265 | $3,250 |
| | 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 | | | | $277 | $276 | $275 | $274 | $273 | $272 | $270 | $268 | $267 | $267 | $266 | $265 | $3,250 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 482,923 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $2,848,870 | 2,848,870 | 2,848,870 | 2,848,870 | 2,848,870 | 2,848,870 | 2,848,870 | 2,848,870 | 2,848,870 | 2,848,870 | 2,848,870 | 2,848,870 | 2,365,947 | |
| 3 | Less: Accumulated Depreciation | | | (289,535) | (293,063) | (296,591) | (300,119) | (303,647) | (307,175) | (310,703) | (314,231) | (317,759) | (321,287) | (324,815) | (328,343) | 151,052 | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $2,559,336 | $2,555,808 | $2,552,280 | $2,548,752 | $2,545,224 | $2,541,696 | $2,538,168 | $2,534,640 | $2,531,112 | $2,527,584 | $2,524,056 | $2,520,528 | $2,517,000 | |
| 6 | Average Net Investment | | | | 2,557,572 | 2,554,044 | 2,550,516 | 2,546,988 | 2,543,460 | 2,539,932 | 2,536,404 | 2,532,876 | 2,529,348 | 2,525,820 | 2,522,292 | 2,518,764 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 4,795 | 4,789 | 4,782 | 4,776 | 4,769 | 4,762 | 4,227 | 4,221 | 4,216 | 4,210 | 4,204 | 4,198 | 53,949 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 17,349 | 17,325 | 17,301 | 17,277 | 17,253 | 17,229 | 17,481 | 17,456 | 17,432 | 17,408 | 17,383 | 17,359 | 208,253 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 1.4860% | | | 3,528 | 3,528 | 3,528 | 3,528 | 3,528 | 3,528 | 3,528 | 3,528 | 3,528 | 3,528 | 3,528 | 3,528 | 42,336 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.017176 | | | 4,078 | 4,078 | 4,078 | 4,078 | 4,078 | 4,078 | 4,078 | 4,078 | 4,078 | 4,078 | 4,078 | 4,078 | 48,936 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $29,750 | $29,720 | $29,689 | $29,659 | $29,628 | $29,597 | $29,314 | $29,283 | $29,254 | $29,224 | $29,193 | $29,163 | $353,474 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $29,750 | $29,720 | $29,689 | $29,659 | $29,628 | $29,597 | $29,314 | $29,283 | $29,254 | $29,224 | $29,193 | $29,163 | $353,474 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (47,586) | (48,111) | (48,636) | (49,161) | (49,686) | (50,211) | (50,736) | (51,261) | (51,786) | (52,311) | (52,836) | (53,361) | (53,886) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $242,712 | $242,187 | $241,662 | $241,137 | $240,612 | $240,087 | $239,562 | $239,037 | $238,512 | $237,987 | $237,462 | $236,937 | $236,412 | |
| 6 | Average Net Investment | | | | 242,449 | 241,924 | 241,399 | 240,874 | 240,349 | 239,824 | 239,299 | 238,774 | 238,249 | 237,724 | 237,199 | 236,674 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 455 | 454 | 453 | 452 | 451 | 450 | 399 | 398 | 397 | 396 | 395 | 394 | 5,094 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 1,645 | 1,641 | 1,637 | 1,634 | 1,630 | 1,627 | 1,649 | 1,646 | 1,642 | 1,638 | 1,635 | 1,631 | 19,655 |
| | 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 | 0.007350 | | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 2,136 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $2,803 | $2,798 | $2,793 | $2,789 | $2,784 | $2,780 | $2,751 | $2,747 | $2,742 | $2,737 | $2,733 | $2,728 | $33,185 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $2,803 | $2,798 | $2,793 | $2,789 | $2,784 | $2,780 | $2,751 | $2,747 | $2,742 | $2,737 | $2,733 | $2,728 | $33,185 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | 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 | | | (23,945) | (24,349) | (24,753) | (25,157) | (25,561) | (25,965) | (26,369) | (26,773) | (27,177) | (27,581) | (27,985) | (28,389) | (28,793) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $137,809 | $137,405 | $137,001 | $136,597 | $136,193 | $135,789 | $135,385 | $134,981 | $134,577 | $134,173 | $133,769 | $133,365 | $132,961 | |
| 6 | Average Net Investment | | | | 137,607 | 137,203 | 136,799 | 136,395 | 135,991 | 135,587 | 135,183 | 134,779 | 134,375 | 133,971 | 133,567 | 133,163 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.25% | 2.00% | 258 | 257 | 256 | 256 | 255 | 254 | 225 | 225 | 224 | 223 | 223 | 222 | 2,878 |
| | b. Equity Component Grossed Up For Taxes | | 8.14% | 8.27% | 933 | 931 | 928 | 925 | 922 | 920 | 932 | 929 | 926 | 923 | 921 | 918 | 11,108 |
| | 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 | 0.008250 | | | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 1,332 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,706 | $1,703 | $1,699 | $1,696 | $1,692 | $1,689 | $1,672 | $1,669 | $1,665 | $1,661 | $1,659 | $1,655 | $20,166 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,706 | $1,703 | $1,699 | $1,696 | $1,692 | $1,689 | $1,672 | $1,669 | $1,665 | $1,661 | $1,659 | $1,655 | $20,166 |

**For Project: CAIR CTs - BARTOW (Project 7.2b)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | 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 | | | (36,673) | (37,031) | (37,389) | (37,747) | (38,105) | (38,463) | (38,821) | (39,179) | (39,537) | (39,895) | (40,253) | (40,611) | (40,969) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $238,674 | $238,316 | $237,958 | $237,600 | $237,242 | $236,884 | $236,526 | $236,168 | $235,810 | $235,452 | $235,094 | $234,736 | $234,378 | |
| 6 | Average Net Investment | | | | 238,495 | 238,137 | 237,779 | 237,421 | 237,063 | 236,705 | 236,347 | 235,989 | 235,631 | 235,273 | 234,915 | 234,557 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.25% | 2.00% | 447 | 447 | 446 | 445 | 444 | 444 | 394 | 393 | 393 | 392 | 392 | 391 | 5,028 |
| | b. Equity Component Grossed Up For Taxes | | 8.14% | 8.27% | 1,618 | 1,615 | 1,613 | 1,611 | 1,608 | 1,606 | 1,629 | 1,626 | 1,624 | 1,621 | 1,619 | 1,617 | 19,407 |
| | 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 | 0.009740 | | | 223 | 223 | 223 | 223 | 223 | 223 | 223 | 223 | 223 | 223 | 223 | 223 | 2,676 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $2,646 | $2,643 | $2,640 | $2,637 | $2,633 | $2,631 | $2,604 | $2,600 | $2,598 | $2,594 | $2,592 | $2,589 | $31,407 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $2,646 | $2,643 | $2,640 | $2,637 | $2,633 | $2,631 | $2,604 | $2,600 | $2,598 | $2,594 | $2,592 | $2,589 | $31,407 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**CAIR CTs (Project 7.2 Recap)**



**For Project: CAIR CTs - BAYBORO (Project 7.2c)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | 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 | | | (29,439) | (29,823) | (30,207) | (30,591) | (30,975) | (31,359) | (31,743) | (32,127) | (32,511) | (32,895) | (33,279) | (33,663) | (34,047) | |
| 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) | | | $169,549 | $169,165 | $168,781 | $168,397 | $168,013 | $167,629 | $167,245 | $166,861 | $166,477 | $166,093 | $165,709 | $165,325 | $164,941 | |
| 6 | Average Net Investment | | | | 169,357 | 168,973 | 168,589 | 168,205 | 167,821 | 167,437 | 167,053 | 166,669 | 166,285 | 165,901 | 165,517 | 165,133 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.25% | 2.00% | 318 | 317 | 316 | 315 | 315 | 314 | 278 | 278 | 277 | 277 | 276 | 275 | 3,556 |
| | b. Equity Component Grossed Up For Taxes | | 8.14% | 8.27% | 1,149 | 1,146 | 1,144 | 1,141 | 1,138 | 1,136 | 1,151 | 1,149 | 1,146 | 1,143 | 1,141 | 1,138 | 13,722 |
| | 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 | 0.009740 | | | 162 | 162 | 162 | 162 | 162 | 162 | 162 | 162 | 162 | 162 | 162 | 162 | 1,944 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $2,013 | $2,009 | $2,006 | $2,002 | $1,999 | $1,996 | $1,975 | $1,973 | $1,969 | $1,966 | $1,963 | $1,959 | $23,830 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $2,013 | $2,009 | $2,006 | $2,002 | $1,999 | $1,996 | $1,975 | $1,973 | $1,969 | $1,966 | $1,963 | $1,959 | $23,830 |

**For Project: CAIR CTs - DeBARY (Project 7.2d)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | 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 | | | (16,887) | (17,106) | (17,325) | (17,544) | (17,763) | (17,982) | (18,201) | (18,420) | (18,639) | (18,858) | (19,077) | (19,296) | (19,515) | |
| 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) | | | $70,780 | $70,561 | $70,342 | $70,123 | $69,904 | $69,685 | $69,466 | $69,247 | $69,028 | $68,809 | $68,590 | $68,371 | $68,152 | |
| 6 | Average Net Investment | | | | 70,670 | 70,451 | 70,232 | 70,013 | 69,794 | 69,575 | 69,356 | 69,137 | 68,918 | 68,699 | 68,480 | 68,261 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.25% | 2.00% | 133 | 132 | 132 | 131 | 131 | 130 | 116 | 115 | 115 | 114 | 114 | 114 | 1,477 |
| | b. Equity Component Grossed Up For Taxes | | 8.14% | 8.27% | 479 | 478 | 476 | 475 | 473 | 472 | 478 | 476 | 475 | 473 | 472 | 470 | 5,697 |
| | 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 | 0.011610 | | | 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) | | | | $916 | $914 | $912 | $910 | $908 | $906 | $898 | $895 | $894 | $891 | $890 | $888 | $10,822 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $916 | $914 | $912 | $910 | $908 | $906 | $898 | $895 | $894 | $891 | $890 | $888 | $10,822 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**CAIR CTs (Project 7.2 Recap)**



**For Project: CAIR CTs - HIGGINS (Project 7.2e)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | 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 | | | (46,905) | (47,744) | (48,583) | (49,422) | (50,261) | (51,100) | (51,939) | (52,778) | (53,617) | (54,456) | (55,295) | (56,134) | (56,973) | |
| 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) | | | $300,293 | $299,454 | $298,615 | $297,776 | $296,937 | $296,098 | $295,259 | $294,420 | $293,581 | $292,742 | $291,903 | $291,064 | $290,225 | |
| 6 | Average Net Investment | | | | 299,873 | 299,034 | 298,195 | 297,356 | 296,517 | 295,678 | 294,839 | 294,000 | 293,161 | 292,322 | 291,483 | 290,644 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.25% | 2.00% | 562 | 561 | 559 | 558 | 556 | 554 | 491 | 490 | 489 | 487 | 486 | 484 | 6,277 |
| | b. Equity Component Grossed Up For Taxes | | 8.14% | 8.27% | 2,034 | 2,028 | 2,023 | 2,017 | 2,011 | 2,006 | 2,032 | 2,026 | 2,020 | 2,015 | 2,009 | 2,003 | 24,224 |
| | 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 | 0.009740 | | | 282 | 282 | 282 | 282 | 282 | 282 | 282 | 282 | 282 | 282 | 282 | 282 | 3,384 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $3,717 | $3,710 | $3,703 | $3,696 | $3,688 | $3,681 | $3,644 | $3,637 | $3,630 | $3,623 | $3,616 | $3,608 | $43,953 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $3,717 | $3,710 | $3,703 | $3,696 | $3,688 | $3,681 | $3,644 | $3,637 | $3,630 | $3,623 | $3,616 | $3,608 | $43,953 |

**For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | 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 | | | (57,235) | (58,022) | (58,809) | (59,596) | (60,383) | (61,170) | (61,957) | (62,744) | (63,531) | (64,318) | (65,105) | (65,892) | (66,679) | |
| 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) | | | $292,349 | $291,562 | $290,775 | $289,988 | $289,201 | $288,414 | $287,627 | $286,840 | $286,053 | $285,266 | $284,479 | $283,692 | $282,905 | |
| 6 | Average Net Investment | | | | 291,955 | 291,168 | 290,381 | 289,594 | 288,807 | 288,020 | 287,233 | 286,446 | 285,659 | 284,872 | 284,085 | 283,298 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.25% | 2.00% | 547 | 546 | 544 | 543 | 542 | 540 | 479 | 477 | 476 | 475 | 473 | 472 | 6,114 |
| | b. Equity Component Grossed Up For Taxes | | 8.14% | 8.27% | 1,980 | 1,975 | 1,970 | 1,964 | 1,959 | 1,954 | 1,980 | 1,974 | 1,969 | 1,963 | 1,958 | 1,952 | 23,598 |
| | 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 | 0.008850 | | | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 3,096 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $3,572 | $3,566 | $3,559 | $3,552 | $3,546 | $3,539 | $3,504 | $3,496 | $3,490 | $3,483 | $3,476 | $3,469 | $42,252 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $3,572 | $3,566 | $3,559 | $3,552 | $3,546 | $3,539 | $3,504 | $3,496 | $3,490 | $3,483 | $3,476 | $3,469 | $42,252 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**CAIR CTs (Project 7.2 Recap)**



**For Project: CAIR CTs - TURNER (Project 7.2g)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | 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 | | | $134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | |
| 3 | Less: Accumulated Depreciation | | | (14,247) | (14,383) | (14,519) | (14,655) | (14,791) | (14,927) | (15,063) | (15,199) | (15,335) | (15,471) | (15,607) | (15,743) | (15,879) | |
| 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) | | | $119,765 | $119,629 | $119,493 | $119,357 | $119,221 | $119,085 | $118,949 | $118,813 | $118,677 | $118,541 | $118,405 | $118,269 | $118,133 | |
| 6 | Average Net Investment | | | | 119,697 | 119,561 | 119,425 | 119,289 | 119,153 | 119,017 | 118,881 | 118,745 | 118,609 | 118,473 | 118,337 | 118,201 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 224 | 224 | 224 | 224 | 223 | 223 | 198 | 198 | 198 | 197 | 197 | 197 | 2,527 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 812 | 811 | 810 | 809 | 808 | 807 | 819 | 818 | 817 | 817 | 816 | 815 | 9,759 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 1.2187% | | | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 1,632 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.011610 | | | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 1,560 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,302 | $1,301 | $1,300 | $1,299 | $1,297 | $1,296 | $1,283 | $1,282 | $1,281 | $1,280 | $1,279 | $1,278 | $15,478 |
| | 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 | | | | $1,302 | $1,301 | $1,300 | $1,299 | $1,297 | $1,296 | $1,283 | $1,282 | $1,281 | $1,280 | $1,279 | $1,278 | $15,478 |

**For Project: CAIR CTs - SUWANNEE (Project 7.2h)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | 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 | | | $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 | | | (35,886) | (36,309) | (36,732) | (37,155) | (37,578) | (38,001) | (38,424) | (38,847) | (39,270) | (39,693) | (40,116) | (40,539) | (40,962) | |
| 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) | | | $345,674 | $345,251 | $344,828 | $344,405 | $343,982 | $343,559 | $343,136 | $342,713 | $342,290 | $341,867 | $341,444 | $341,021 | $340,598 | |
| 6 | Average Net Investment | | | | 345,462 | 345,039 | 344,616 | 344,193 | 343,770 | 343,347 | 342,924 | 342,501 | 342,078 | 341,655 | 341,232 | 340,809 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 648 | 647 | 646 | 645 | 645 | 644 | 572 | 571 | 570 | 569 | 569 | 568 | 7,294 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 2,343 | 2,341 | 2,338 | 2,335 | 2,332 | 2,329 | 2,363 | 2,360 | 2,358 | 2,355 | 2,352 | 2,349 | 28,155 |
| | 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 | 0.008210 | | | 261 | 261 | 261 | 261 | 261 | 261 | 261 | 261 | 261 | 261 | 261 | 261 | 3,132 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $3,675 | $3,672 | $3,668 | $3,664 | $3,661 | $3,657 | $3,619 | $3,615 | $3,612 | $3,608 | $3,605 | $3,601 | $43,657 |
| | 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 | | | | $3,675 | $3,672 | $3,668 | $3,664 | $3,661 | $3,657 | $3,619 | $3,615 | $3,612 | $3,608 | $3,605 | $3,601 | $43,657 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions (B) | | | | $224,169 | ($186,001) | $12,286 | $24,812 | $2,722 | $6,382 | $10,042 | $9,589 | $4,319 | $6,030 | $410,015 | $26,796 | $551,162 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (C) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | ($198,980) | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $16,857 | 16,857 | 16,857 | 16,857 | 16,857 | 16,857 | 16,857 | 16,857 | 16,857 | 16,857 | 16,857 | 16,857 | 16,857 | |
| 3 | Less: Accumulated Depreciation | | | (80) | (115) | (150) | (185) | (220) | (255) | (290) | (325) | (360) | (395) | (430) | (465) | (500) | |
| 4 | CWIP - Non-Interest Bearing | | | 1,651,733 | 1,875,902 | 1,689,901 | 1,702,187 | 1,727,000 | 1,729,722 | 1,736,104 | 1,746,147 | 1,755,735 | 1,561,074 | 1,567,104 | 1,977,119 | 2,003,915 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $1,668,511 | $1,892,645 | $1,706,609 | $1,718,860 | $1,743,638 | $1,746,325 | $1,752,672 | $1,762,679 | $1,772,233 | $1,577,537 | $1,583,532 | $1,993,512 | $2,020,273 | |
| 6 | Average Net Investment | | | | 1,780,578 | 1,799,627 | 1,712,735 | 1,731,249 | 1,744,981 | 1,749,499 | 1,757,676 | 1,767,456 | 1,674,885 | 1,580,534 | 1,788,522 | 2,006,892 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 3,339 | 3,374 | 3,211 | 3,246 | 3,272 | 3,280 | 2,929 | 2,946 | 2,791 | 2,634 | 2,981 | 3,345 | 37,348 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 12,078 | 12,207 | 11,618 | 11,744 | 11,837 | 11,867 | 12,114 | 12,181 | 11,543 | 10,893 | 12,326 | 13,831 | 144,239 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 2.4700% | | | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 420 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.017176 | | | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 288 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $15,476 | $15,640 | $14,888 | $15,049 | $15,168 | $15,206 | $15,102 | $15,186 | $14,393 | $13,586 | $15,366 | $17,235 | $182,295 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $15,476 | $15,640 | $14,888 | $15,049 | $15,168 | $15,206 | $15,102 | $15,186 | $14,393 | $13,586 | $15,366 | $17,235 | $182,295 |

**For Project: Crystal River 4 and 5 - Conditions of Certification (Project 7.4q)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | ($4,484) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($4,484) |
| | b. Clearings to Plant | | | | 0 | (4,484) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $618,493 | 618,493 | 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 | | | (383) | (1,149) | (1,909) | (2,669) | (3,429) | (4,189) | (4,949) | (5,709) | (6,469) | (7,229) | (7,989) | (8,749) | (9,509) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $618,110 | $617,344 | $612,101 | $611,341 | $610,581 | $609,821 | $609,061 | $608,301 | $607,541 | $606,781 | $606,021 | $605,261 | $604,501 | |
| 6 | Average Net Investment | | | | 617,727 | 614,723 | 611,721 | 610,961 | 610,201 | 609,441 | 608,681 | 607,921 | 607,161 | 606,401 | 605,641 | 604,881 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 1,158 | 1,153 | 1,147 | 1,146 | 1,144 | 1,143 | 1,014 | 1,013 | 1,012 | 1,011 | 1,009 | 1,008 | 12,958 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 4,190 | 4,170 | 4,150 | 4,144 | 4,139 | 4,134 | 4,195 | 4,190 | 4,184 | 4,179 | 4,174 | 4,169 | 50,018 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 1.4860% | | | 766 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 9,126 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.017176 | | | 885 | 879 | 879 | 879 | 879 | 879 | 879 | 879 | 879 | 879 | 879 | 879 | 10,554 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $6,999 | $6,962 | $6,936 | $6,929 | $6,922 | $6,916 | $6,848 | $6,842 | $6,835 | $6,829 | $6,822 | $6,816 | $82,656 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $6,999 | $6,962 | $6,936 | $6,929 | $6,922 | $6,916 | $6,848 | $6,842 | $6,835 | $6,829 | $6,822 | $6,816 | $82,656 |

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-13-0598-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-12-0425-PAA-EU.
(B) Credit in 2/14 is for the reversal of a 12/13 accrual that was inadertantly re-accrued in 1/14.
(C) Credit in 9/14 is for CWIP FGD Blowdown Treatment costs moved from capital to O&M.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**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-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (11,291) | (12,652) | (14,013) | (15,374) | (16,735) | (18,096) | (19,457) | (20,818) | (22,179) | (23,540) | (24,901) | (26,262) | (27,623) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $649,707 | $648,346 | $646,985 | $645,624 | $644,263 | $642,902 | $641,541 | $640,180 | $638,819 | $637,458 | $636,097 | $634,736 | $633,375 | |
| 6 | Average Net Investment | | | | 649,027 | 647,666 | 646,305 | 644,944 | 643,583 | 642,222 | 640,861 | 639,500 | 638,139 | 636,778 | 635,417 | 634,056 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 1,217 | 1,214 | 1,212 | 1,209 | 1,207 | 1,204 | 1,068 | 1,066 | 1,064 | 1,061 | 1,059 | 1,057 | 13,638 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 4,403 | 4,393 | 4,384 | 4,375 | 4,366 | 4,356 | 4,417 | 4,407 | 4,398 | 4,389 | 4,379 | 4,370 | 52,637 |
| | 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 | 0.017176 | | | 946 | 946 | 946 | 946 | 946 | 946 | 946 | 946 | 946 | 946 | 946 | 946 | 11,352 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $7,927 | $7,914 | $7,903 | $7,891 | $7,880 | $7,867 | $7,792 | $7,780 | $7,769 | $7,757 | $7,745 | $7,734 | $93,959 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $7,927 | $7,914 | $7,903 | $7,891 | $7,880 | $7,867 | $7,792 | $7,780 | $7,769 | $7,757 | $7,745 | $7,734 | $93,959 |

**For Project: CAIR Crystal River - FGD Common (Project 7.4s) - CR5 Clinker Mitigation**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $16,809 | $38,261 | $126,757 | $749 | $0 | $5,255 | $0 | $0 | $0 | $0 | $0 | $0 | $187,832 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 500,649 | 0 | 5,255 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | 500,649 | 500,649 | 505,904 | 505,904 | 505,904 | 505,904 | 505,904 | 505,904 | 505,904 | |
| 3 | Less: Accumulated Depreciation | | | 0 | 0 | 0 | 0 | 0 | (1,031) | (2,072) | (3,113) | (4,154) | (5,195) | (6,236) | (7,277) | (8,318) | |
| 4 | CWIP - Non-Interest Bearing | | | 318,072 | 334,881 | 373,143 | 499,900 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $318,072 | $334,881 | $373,143 | $499,900 | $500,649 | $499,618 | $503,832 | $502,791 | $501,750 | $500,709 | $499,668 | $498,627 | $497,586 | |
| 6 | Return on Average Net Investment (A) | | | | 326,477 | 354,012 | 436,522 | 500,275 | 500,134 | 501,725 | 503,312 | 502,271 | 501,230 | 500,189 | 499,148 | 498,107 | |
| 7 | Return on Average Net Investment | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 612 | 664 | 818 | 938 | 938 | 941 | 839 | 837 | 835 | 834 | 832 | 830 | 9,918 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 2,215 | 2,401 | 2,961 | 3,394 | 3,393 | 3,403 | 3,469 | 3,462 | 3,454 | 3,447 | 3,440 | 3,433 | 38,472 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 2.4700% | | | 0 | 0 | 0 | 0 | 1,031 | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 8,318 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.017176 | | | 0 | 0 | 0 | 0 | 717 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 5,785 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $2,827 | $3,065 | $3,779 | $4,332 | $6,079 | $6,109 | $6,073 | $6,064 | $6,054 | $6,046 | $6,037 | $6,028 | $62,493 |
| | 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 | | | | $2,827 | $3,065 | $3,779 | $4,332 | $6,079 | $6,109 | $6,073 | $6,064 | $6,054 | $6,046 | $6,037 | $6,028 | $62,493 |

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-13-0598-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-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**Thermal Discharge Permanent Cooling Tower (Project 11.1 Recap)**



**For Project: Crystal River Thermal Discharge Compliance Project AFUDC - Point of Discharge (POD) Cooling Tower (Project 11.1a)**
**(in Dollars)**
**(Activity Prior to 1/1/13)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | (512,000) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Regulatory Asset Balance | | | $11,835,738 | 11,835,738 | 11,342,582 | 10,849,426 | 10,356,271 | 9,351,115 | 8,883,559 | 8,416,003 | 7,948,448 | 7,480,892 | 7,013,336 | 6,545,780 | 6,078,225 | |
| 3 | Less: Amortization (C) | | | 0 | (493,156) | (493,156) | (493,156) | (493,156) | (467,556) | (467,556) | (467,556) | (467,556) | (467,556) | (467,556) | (467,556) | (467,556) | |
| 4 | CWIP - AFUDC Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3) | | | $11,835,738 | $11,342,582 | $10,849,426 | $10,356,271 | $9,863,115 | $8,883,559 | $8,416,003 | $7,948,448 | $7,480,892 | $7,013,336 | $6,545,780 | $6,078,225 | $5,610,669 | |
| 6 | Average Net Investment | | | | 11,589,160 | 11,096,004 | 10,602,848 | 10,109,693 | 9,373,337 | 8,649,781 | 8,182,225 | 7,714,670 | 7,247,114 | 6,779,558 | 6,312,002 | 5,844,447 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 21,730 | 20,805 | 19,880 | 18,956 | 17,575 | 16,218 | 13,637 | 12,858 | 12,079 | 11,299 | 10,520 | 9,741 | 185,298 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 78,613 | 75,268 | 71,923 | 68,577 | 63,583 | 58,674 | 56,391 | 53,169 | 49,946 | 46,724 | 43,502 | 40,279 | 706,649 |
| | c. Other | | | | (20,443) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (20,443) |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization (C) | 33.3333% | | | 493,156 | 493,156 | 493,156 | 493,156 | 467,556 | 467,556 | 467,556 | 467,556 | 467,556 | 467,556 | 467,556 | 467,556 | 5,713,069 |
| | c. Dismantlement | | | | N/A | N/A | N/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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $573,056 | $589,229 | $584,959 | $580,689 | $548,714 | $542,448 | $537,584 | $533,583 | $529,581 | $525,579 | $521,578 | $517,576 | 6,584,573 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $573,056 | $589,229 | $584,959 | $580,689 | $548,714 | $542,448 | $537,584 | $533,583 | $529,581 | $525,579 | $521,578 | $517,576 | 6,584,573 |

**For Project: Crystal River Thermal Discharge Compliance Project AFUDC - MET Tower (Project 11.1b)**
**(in Dollars)**
**(Activity Prior to 1/1/13)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Regulatory Asset Balance | | | $227,318 | 227,318 | 217,847 | 208,375 | 198,904 | 189,432 | 179,960 | 170,489 | 161,017 | 151,546 | 142,074 | 132,602 | 123,131 | |
| 3 | Less: Amortization (C) | | | 0 | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $227,318 | $217,847 | $208,375 | $198,904 | $189,432 | $179,960 | $170,489 | $161,017 | $151,546 | $142,074 | $132,602 | $123,131 | $113,659 | |
| 6 | Average Net Investment | | | | 222,583 | 213,111 | 203,639 | 194,168 | 184,696 | 175,225 | 165,753 | 156,281 | 146,810 | 137,338 | 127,867 | 118,395 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 417 | 400 | 382 | 364 | 346 | 329 | 276 | 260 | 245 | 229 | 213 | 197 | 3,658 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 1,510 | 1,446 | 1,381 | 1,317 | 1,253 | 1,189 | 1,142 | 1,077 | 1,012 | 947 | 881 | 816 | 13,971 |
| | c. Other | | | | 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 (C) | 33.3333% | | | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 113,659 |
| | c. Dismantlement | | | | N/A | N/A | N/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) | 0.001728 | | | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 625 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $11,451 | $11,370 | $11,287 | $11,205 | $11,123 | $11,042 | $10,942 | $10,861 | $10,781 | $10,700 | $10,618 | $10,537 | $131,913 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $11,451 | $11,370 | $11,287 | $11,205 | $11,123 | $11,042 | $10,942 | $10,861 | $10,781 | $10,700 | $10,618 | $10,537 | $131,913 |

(A) [redacted] **REDACTED**
(B) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.
(C) Investment amortized over three years in accordance with Order No. PSC-13-0381-PAA-EI.
(D) Property tax calculated on original asset basis of $361,735.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2014 through December 2014**
**Thermal Discharge Permanent Cooling Tower (Project 11.1 Recap)**



**For Project: Crystal River Thermal Discharge Compliance Project AFUDC - Point of Discharge (POD) Cooling Tower (Project 11.1a)**
**(in Dollars)**
**(Activity After 12/31/12)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Regulatory Asset Balance | | | $76,050 | 76,050 | 72,881 | 69,713 | 66,544 | 63,375 | 60,206 | 57,038 | 53,869 | 50,700 | 47,531 | 44,363 | 41,194 | $703,464 |
| 3 | Less: Amortization (A) | | | 0 | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | ($38,025) |
| 4 | CWIP - AFUDC Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $0 |
| 5 | Net Investment (Lines 2 + 3) | | | $76,050 | $72,881 | $69,713 | $66,544 | $63,375 | $60,206 | $57,038 | $53,869 | $50,700 | $47,531 | $44,363 | $41,194 | $38,025 | $665,439 |
| 6 | Average Net Investment | | | | 74,466 | 71,297 | 68,128 | 64,960 | 61,791 | 58,622 | 55,453 | 52,284 | 49,116 | 45,947 | 42,778 | 39,609 | $684,451 |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | 140 | 134 | 128 | 122 | 116 | 110 | 92 | 87 | 82 | 77 | 71 | 66 | 1,225 |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | 505 | 484 | 462 | 441 | 419 | 398 | 382 | 360 | 339 | 317 | 295 | 273 | 4,675 |
| | c. Other | | | | | 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 (A) | 33.3333% | | | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 38,025 |
| | c. Dismantlement | | | | N/A | N/A | N/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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $3,814 | $3,787 | $3,759 | $3,732 | $3,704 | $3,677 | $3,643 | $3,616 | $3,590 | $3,563 | $3,535 | $3,508 | 43,925 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $3,814 | $3,787 | $3,759 | $3,732 | $3,704 | $3,677 | $3,643 | $3,616 | $3,590 | $3,563 | $3,535 | $3,508 | 43,925 |

**For Project: Crystal River Thermal Discharge Compliance Project AFUDC - MET Tower (Project 11.1b)**
**(in Dollars)**
**(Activity After 12/31/12)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Regulatory Asset Balance | | | ($3,412) | (3,412) | (3,270) | (3,128) | (2,986) | (2,844) | (2,702) | (2,559) | (2,417) | (2,275) | (2,133) | (1,991) | (1,848) | ($31,565) |
| 3 | Less: Amortization (A) | | | 0 | 142 | 142 | 142 | 142 | 142 | 142 | 142 | 142 | 142 | 142 | 142 | 142 | $1,706 |
| 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) | | | ($3,412) | ($3,270) | ($3,128) | ($2,986) | ($2,844) | ($2,702) | ($2,559) | ($2,417) | ($2,275) | ($2,133) | ($1,991) | ($1,848) | ($1,706) | ($29,859) |
| 6 | Average Net Investment | | | | (3,341) | (3,199) | (3,057) | (2,915) | (2,773) | (2,630) | (2,488) | (2,346) | (2,204) | (2,062) | (1,920) | (1,777) | ($30,712) |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.25% | 2.00% | | (6) | (6) | (6) | (5) | (5) | (5) | (4) | (4) | (4) | (3) | (3) | (3) | (54) |
| | b. Equity Component Grossed Up For Taxes | 8.14% | 8.27% | | (23) | (22) | (21) | (20) | (19) | (18) | (17) | (16) | (15) | (14) | (13) | (12) | (210) |
| | c. Other | | | | 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 (A) | 33.3333% | | | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (1,706) |
| | c. Dismantlement | | | | N/A | N/A | N/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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | ($171) | ($170) | ($169) | ($167) | ($166) | ($165) | ($163) | ($162) | ($161) | ($159) | ($158) | ($157) | ($1,970) |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | ($171) | ($170) | ($169) | ($167) | ($166) | ($165) | ($163) | ($162) | ($161) | ($159) | ($158) | ($157) | ($1,970) |

(A) Investment amortized over three years in accordance with Order No. PSC-13-0381-PAA-EI.
(B) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Commission Forms 42-1E Through 42-9E**

**January 2015- December 2015**
**Calculation for the Current Period Actual / Estimated Amount**
**Actuals for the Period January 2015 - June 2015**
**Estimates for the Period July 2015 - December 2015**

**Docket No. 150007-EI**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 12
PARTY: DUKE ENERGY FLORIDA, LLC
(DEF) – (DIRECT)
DESCRIPTION: Thomas G. Foster TGF-3

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Calculation of Actual / Estimated Amount**
**January 2015 - December 2015**
**(in Dollars)**



| Line | | Period Amount |
|---|---|---|
| 1 | Over/(Under) Recovery for the Period (Form 42-2E, Line 5) | $ (787,565) |
| 2 | Interest Provision (Form 42-2E, Line 6) | 7,963 |
| 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 2016 to December 2016 (Lines 1 + 2 +3) | $ (779,602) |

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Calculation of Actual / Estimated Amount**
**January 2015 - December 2015**

**End-of-Period True-Up Amount**
**(in Dollars)**

| Line | Description | | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (net of Revenue Taxes) | | $3,526,142 | $3,506,269 | $3,739,966 | $3,893,292 | $4,144,320 | $4,771,971 | $5,055,172 | $5,102,618 | $5,151,316 | $4,749,354 | $3,987,776 | $3,691,015 | $51,319,212 |
| 2 | True-Up Provision (Order No. PSC-14-0643-FOF-EI) | 15,152,979 | 1,262,748 | 1,262,748 | 1,262,748 | 1,262,748 | 1,262,748 | 1,262,748 | 1,262,748 | 1,262,748 | 1,262,748 | 1,262,748 | 1,262,748 | 1,262,748 | 15,152,979 |
| 3 | ECRC Revenues Applicable to Period (Lines 1 + 2) | | $4,788,890 | 4,769,017 | 5,002,714 | 5,156,040 | 5,407,068 | 6,034,720 | 6,317,920 | 6,365,366 | 6,414,064 | 6,012,102 | 5,250,525 | 4,953,764 | 66,472,191 |
| 4 | Jurisdictional ECRC Costs | | | | | | | | | | | | | | |
| | a. O & M Activities (Form 42-5E, Line 9) | | $2,261,276 | 3,308,076 | 3,001,928 | 2,882,870 | 3,020,190 | 2,307,839 | 3,491,803 | 3,701,012 | 3,543,366 | 3,342,029 | 2,991,418 | 4,161,811 | 38,013,623 |
| | b. Capital Investment Projects (Form 42-7E, Line 9) | | 2,406,310 | 2,430,007 | 2,426,400 | 2,420,237 | 2,406,987 | 2,461,109 | 2,510,481 | 2,518,972 | 2,529,213 | 2,532,769 | 2,548,249 | 2,560,420 | 29,751,155 |
| | c. Other (A) | | | | | | | ($505,022) | | | | | | | (505,022) |
| | d. Total Jurisdictional ECRC Costs | | $4,667,587 | $5,738,084 | $5,428,328 | $5,303,107 | $5,427,178 | $4,263,927 | $6,002,284 | $6,219,984 | $6,072,579 | $5,874,799 | $5,539,667 | $6,722,231 | 67,259,756 |
| 5 | Over/(Under) Recovery (Line 3 - Line 4d) | | $121,304 | (969,066) | (425,614) | (147,067) | (20,109) | 1,770,793 | 315,636 | 145,382 | 341,485 | 137,303 | (289,143) | (1,768,468) | (787,565) |
| 6 | Interest Provision (Form 42-3E, Line 10) | | 1,280 | 1,145 | 989 | 649 | 662 | 726 | 620 | 548 | 477 | 405 | 311 | 151 | 7,963 |
| 7 | Beginning Balance True-Up & Interest Provision | | 15,152,979 | 14,012,814 | 11,782,145 | 10,094,771 | 8,685,605 | 7,403,410 | 7,912,180 | 6,965,688 | 5,848,869 | 4,928,083 | 3,803,043 | 2,251,463 | 15,152,979 |
| | a. Deferred True-Up - January 2014 to December 2014 (2014 TU filing dated 4/1/15) | | 1,419,043 | 1,419,043 | 1,419,043 | 1,419,043 | 1,419,043 | 1,419,043 | 1,419,043 | 1,419,043 | 1,419,043 | 1,419,043 | 1,419,043 | 1,419,043 | 1,419,043 |
| 8 | True-Up Collected/(Refunded) (Line 2) | | (1,262,748) | (1,262,748) | (1,262,748) | (1,262,748) | (1,262,748) | (1,262,748) | (1,262,748) | (1,262,748) | (1,262,748) | (1,262,748) | (1,262,748) | (1,262,748) | (15,152,979) |
| 9 | End of Period Total True-Up (Lines 5+6+7+7a+8) | | $15,431,857 | 13,201,188 | 11,513,814 | 10,104,648 | 8,822,453 | 9,331,223 | 8,384,731 | 7,267,913 | 6,347,126 | 5,222,086 | 3,670,506 | 639,441 | 639,441 |
| 10 | Adjustments to Period Total True-Up Including Interest | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | End of Period Total True-Up (Over/(Under) (Lines 9 + 10) | | $15,431,857 | $13,201,188 | $11,513,814 | $10,104,648 | $8,822,453 | $9,331,223 | 8,384,731 | $7,267,913 | $6,347,126 | $5,222,086 | $3,670,506 | $639,441 | $639,441 |

Notes:

(A) Other amount represents the retail portion of 2014 cost adjustments.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Calculation of Actual / Estimated Amount**
**January 2015 - December 2015**

**Interest Provision**
**(in Dollars)**

| Line | Description | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10) | $16,572,022 | $15,431,857 | $13,201,188 | $11,513,814 | $10,104,648 | $8,822,453 | $9,331,223 | $8,384,731 | $7,267,913 | $6,347,126 | $5,222,086 | $3,670,506 | |
| 2 | Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8) | 15,430,577 | 13,200,043 | 11,512,825 | 10,103,999 | 8,821,791 | 9,330,497 | 8,384,111 | 7,267,365 | 6,346,649 | 5,221,681 | 3,670,195 | 639,290 | |
| 3 | Total of Beginning & Ending True-Up (Lines 1 + 2) | 32,002,600 | 28,631,900 | 24,714,013 | 21,617,814 | 18,926,439 | 18,152,950 | 17,715,334 | 15,652,096 | 13,614,562 | 11,568,807 | 8,892,281 | 4,309,796 | |
| 4 | Average True-Up Amount (Line 3 x 1/2) | 16,001,300 | 14,315,950 | 12,357,007 | 10,808,907 | 9,463,220 | 9,076,475 | 8,857,667 | 7,826,048 | 6,807,281 | 5,784,404 | 4,446,141 | 2,154,898 | |
| 5 | Interest Rate (Last Business Day of Prior Month) | 0.10% | 0.10% | 0.09% | 0.09% | 0.06% | 0.10% | 0.08% | 0.08% | 0.08% | 0.08% | 0.08% | 0.08% | |
| 6 | Interest Rate (Last Business Day of Current Month) | 0.10% | 0.09% | 0.09% | 0.06% | 0.10% | 0.08% | 0.08% | 0.08% | 0.08% | 0.08% | 0.08% | 0.08% | |
| 7 | Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 0.20% | 0.19% | 0.18% | 0.15% | 0.16% | 0.18% | 0.16% | 0.16% | 0.16% | 0.16% | 0.16% | 0.16% | |
| 8 | Average Interest Rate (Line 7 x 1/2) | 0.100% | 0.095% | 0.090% | 0.075% | 0.080% | 0.090% | 0.080% | 0.080% | 0.080% | 0.080% | 0.080% | 0.080% | |
| 9 | Monthly Average Interest Rate (Line 8 x 1/12) | 0.008% | 0.008% | 0.008% | 0.006% | 0.007% | 0.008% | 0.007% | 0.007% | 0.007% | 0.007% | 0.007% | 0.007% | |
| 10 | Interest Provision for the Month (Line 4 x Line 9) | $1,280 | $1,145 | $989 | $649 | $662 | $726 | $620 | $548 | $477 | $405 | $311 | $151 | $7,963 |

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Calculation of Actual / Estimated Amount**
**January 2015 - December 2015**

**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 | $1,275,359 | $737,004 | $538,355 | 73% |
| | 1a | Distribution Substation Environmental Investigation, Remediation and Pollution Prevention | (166,032) | 777,000 | (943,032) | -121% |
| | 2 | Distribution System Environmental Investigation, Remediation and Pollution Prevention | 58,344 | 16,000 | 42,344 | 265% |
| | 3 | Pipeline Integrity Management - Bartow /Anclote Pipeline - Intm | 516,698 | 497,610 | 19,088 | 4% |
| | 4 | Above Ground Tank Secondary Containment | 0 | 0 | 0 | 0% |
| | 5 | SO2/NOx Emissions Allowances - Energy | 3,614,732 | 2,158,534 | 1,456,198 | 67% |
| | 6 | Phase II Cooling Water Intake 316(b) - Base | 146,275 | 180,000 | (33,725) | -19% |
| | 6.a | Phase II Cooling Water Intake 316(b) - Intm | 130,350 | 140,000 | (9,650) | -7% |
| | 7.2 | CAIR/CAMR - Peaking | 48,570 | 47,174 | 1,396 | 3% |
| | 7.4 | CAIR/CAMR Crystal River - Base | 15,306,635 | 16,017,101 | (710,466) | -4% |
| | 7.4 | CAIR/CAMR Crystal River - Energy | 14,267,141 | 12,887,257 | 1,379,884 | 11% |
| | 7.4 | CAIR/CAMR Crystal River - A&G | 137,080 | 148,737 | (11,658) | -8% |
| | 7.4 | CAIR/CAMR Crystal River - Conditions of Certification - Energy | 3,457 | 0 | 3,457 | 100% |
| | 7.5 | Best Available Retrofit Technology (BART) - Energy | 0 | 0 | 0 | 0% |
| | 8 | Arsenic Groundwater Standard - Base | 39,116 | 16,000 | 23,116 | 144% |
| | 9 | Sea Turtle - Coastal Street Lighting - Distrib | 1,132 | 1,200 | (68) | -6% |
| | 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% |
| | 16 | National Pollutant Discharge Elimination System (NPDES) - Energy | 217,622 | 271,200 | (53,578) | -20% |
| | 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 585,126 | 431,723 | 153,403 | 36% |
| | 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 | 3,748,826 | 3,799,988 | (51,162) | -1% |
| | 18 | Coal Combustion Residual (CCR) Rule - Energy | 391,004 | 0 | 391,004 | 100% |
| 2 | | Total O&M Activities - Recoverable Costs | $40,321,435 | $38,126,529 | $2,194,906 | 6% |
| 3 | | Recoverable Costs Allocated to Energy | 22,827,908 | 19,548,702 | 3,279,206 | 17% |
| 4 | | Recoverable Costs Allocated to Demand | $17,493,527 | $18,577,827 | ($1,084,300) | -6% |

Notes:

Column (1) - End of Period Totals on Form 42-5E
Column (2) - 2015 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 2015 - December 2015**

**O&M Activities**
**(in Dollars)**

| Line | Description | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | O&M Activities - System | | | | | | | | | | | | | |
| 1 | Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention | ($18,825) | $28,217 | ($15,474) | $33,802 | ($23,735) | $236,136 | $697,565 | $67,534 | $67,534 | $67,534 | $67,534 | $67,534 | $1,275,359 |
| 1a | Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention | 105,181 | 69,374 | 49,077 | 54,260 | 83,342 | (210,344) | (514,256) | 39,467 | 39,467 | 39,467 | 39,467 | 39,467 | (166,032) |
| 2 | Distribution System Environmental Investigation, Remediation, and Pollution Prevention | 476 | 368 | 0 | 4,093 | 0 | 1,323 | 13,869 | 25,069 | 1,624 | 1,624 | 1,624 | 8,274 | 58,344 |
| 3 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | 29,476 | 79,207 | 83,458 | 49,356 | 49,845 | 5,644 | 44,656 | 35,011 | 35,011 | 35,011 | 35,011 | 35,011 | 516,698 |
| 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 | (8,868) | (6,935) | (7,374) | (8,585) | (2,165) | 2,130 | 6,537 | 9,890 | 8,606 | 9,144 | (8,663) | (8,142) | (14,424) |
| 5 | NOx Emissions Allowances Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 6 | Phase II Cooling Water Intake 316(b) - Base | 0 | 35,625 | 0 | 15,836 | 14,814 | 17,400 | 0 | 20,867 | 20,867 | 20,867 | 0 | 0 | 146,275 |
| 6a | Phase II Cooling Water Intake 316(b) - Intm | 30,255 | (776) | 22,264 | 20,009 | 18,523 | 657 | 0 | 0 | 0 | 0 | 0 | 39,417 | 130,350 |
| 7.2 | CAIR/CAMR - Peaking | 29,570 | 0 | 19,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 48,570 |
| 7.4 | CAIR/CAMR Crystal River - Base | 1,084,061 | 1,133,842 | 1,126,742 | 1,194,033 | 1,395,628 | 1,169,897 | 1,214,572 | 1,212,572 | 1,195,572 | 1,304,572 | 1,372,572 | 1,902,572 | 15,306,635 |
| 7.4 | CAIR/CAMR Crystal River - Energy | 741,862 | 930,348 | 1,377,092 | 1,275,650 | 1,009,776 | 793,128 | 1,234,626 | 1,470,883 | 1,429,691 | 1,523,973 | 1,042,896 | 1,437,217 | 14,267,141 |
| 7.4 | CAIR/CAMR Crystal River - A&G | 8,693 | 6,214 | 14,399 | 8,455 | 16,633 | 14,146 | 11,423 | 11,423 | 11,423 | 11,423 | 11,423 | 11,423 | 137,080 |
| 7.4 | CAIR/CAMR Crystal River - Conditions of Certification - Energy | 0 | 3,457 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,457 |
| 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 | 7,444 | 1,187 | 0 | 6,936 | 0 | 8,019 | 0 | 15,531 | 0 | 0 | 0 | 0 | 39,116 |
| 9 | Sea Turtle - Coastal Street Lighting - Distrib | 0 | 0 | 0 | 0 | 0 | 0 | 982 | 50 | 50 | 50 | 0 | 0 | 1,132 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Energy | 4,640 | (16,114) | 24,512 | 72,556 | 8,095 | 32,769 | 0 | 13,683 | 41,915 | 0 | 3,383 | 32,183 | 217,622 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 43,654 | 1,269 | 6,086 | 9,497 | 454 | 16,823 | 82,649 | 82,649 | 99,349 | 80,899 | 80,899 | 80,899 | 585,126 |
| 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 | 22,871 | 896,818 | 148,602 | 16,231 | 337,304 | 123,730 | 653,378 | 478,378 | 431,378 | 83,378 | 168,378 | 388,378 | 3,748,826 |
| 18.0 | Coal Combustion Residual (CCR) Rule - Energy | 0 | 0 | 0 | 0 | 0 | 0 | 110,302 | 104,702 | 44,000 | 44,000 | 44,000 | 44,000 | 391,004 |
| 2 | Total O&M Activities - Recoverable Costs | $2,382,920 | $3,464,531 | $3,150,814 | $3,054,559 | $3,210,944 | $2,513,887 | $3,858,734 | $3,890,140 | $3,728,917 | $3,524,372 | $3,160,954 | $4,380,664 | $40,321,435 |
| 3 | Recoverable Costs Allocated to Energy | 804,159 | 1,808,843 | 1,548,918 | 1,365,349 | 1,353,464 | 968,579 | 2,087,493 | 2,160,185 | 2,054,939 | 1,741,394 | 1,330,893 | 1,974,536 | 19,198,752 |
| | Recoverable Costs Allocated to Energy - NOx Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 4 | Recoverable Costs Allocated to Demand - Transm | (18,825) | 28,217 | (15,474) | 33,802 | (23,735) | 236,136 | 697,565 | 67,534 | 67,534 | 67,534 | 67,534 | 67,534 | 1,275,359 |
| | Recoverable Costs Allocated to Demand - Distrib | 105,657 | 69,743 | 49,077 | 58,352 | 83,342 | (209,021) | (499,405) | 64,586 | 41,141 | 41,141 | 41,091 | 47,741 | (106,556) |
| | Recoverable Costs Allocated to Demand - Prod-Base | 1,091,505 | 1,170,653 | 1,126,742 | 1,216,805 | 1,410,443 | 1,195,316 | 1,214,572 | 1,248,970 | 1,216,438 | 1,325,438 | 1,372,572 | 1,902,572 | 15,492,027 |
| | Recoverable Costs Allocated to Demand - Prod-Intm | 59,732 | 78,431 | 105,722 | 69,365 | 68,369 | 6,301 | 44,656 | 35,011 | 35,011 | 35,011 | 35,011 | 74,428 | 647,049 |
| | Recoverable Costs Allocated to Demand - Prod-Peaking | 29,570 | 0 | 19,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 48,570 |
| | Recoverable Costs Allocated to Demand - A&G | 8,693 | 6,214 | 14,399 | 8,455 | 16,633 | 14,146 | 11,423 | 11,423 | 11,423 | 11,423 | 11,423 | 11,423 | 137,080 |
| 5 | Retail Energy Jurisdictional Factor | 0.96920 | 0.97990 | 0.97660 | 0.96410 | 0.94750 | 0.95600 | 0.97335 | 0.97071 | 0.96978 | 0.97063 | 0.97372 | 0.98187 | |
| | 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) | 779,391 | 1,772,485 | 1,512,673 | 1,316,333 | 1,282,407 | 925,961 | 2,031,865 | 2,096,921 | 1,992,834 | 1,690,252 | 1,295,911 | 1,938,735 | 18,635,768 |
| | Retail Energy Jurisdictional Factor - NOx Regulatory Asset (A) | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 8 | Jurisdictional Demand Recoverable Costs - Transm (B) | (13,215) | 19,809 | (10,863) | 23,730 | (16,663) | 165,775 | 489,712 | 47,411 | 47,411 | 47,411 | 47,411 | 47,411 | 895,340 |
| | Jurisdictional Demand Recoverable Costs - Distrib (B) | 105,193 | 69,437 | 48,862 | 58,096 | 82,976 | (208,103) | (497,213) | 64,302 | 40,960 | 40,960 | 40,911 | 47,531 | (106,088) |
| | Jurisdictional Demand Recoverable Costs - Prod-Base (B) | 1,013,844 | 1,087,361 | 1,046,575 | 1,130,230 | 1,310,090 | 1,110,269 | 1,128,155 | 1,160,106 | 1,129,889 | 1,231,134 | 1,274,913 | 1,767,204 | 14,389,770 |
| | Jurisdictional Demand Recoverable Costs - Prod-Intm (B) | 43,427 | 57,022 | 76,863 | 50,430 | 49,706 | 4,581 | 32,466 | 25,454 | 25,454 | 25,454 | 25,454 | 54,112 | 470,423 |
| | Jurisdictional Demand Recoverable Costs - Prod-Peaking (B) | 28,364 | 0 | 18,226 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 46,590 |
| | Jurisdictional Demand Recoverable Costs - A&G (B) | 8,103 | 5,793 | 13,423 | 7,882 | 15,505 | 13,187 | 10,649 | 10,649 | 10,649 | 10,649 | 10,649 | 10,649 | 127,787 |
| 9 | Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8) | $2,261,276 | $3,308,076 | $3,001,928 | $2,882,870 | $3,020,190 | $2,307,839 | $3,491,803 | $3,701,012 | $3,543,366 | $3,342,029 | $2,991,418 | $4,161,811 | $38,013,623 |

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 2015 - December 2015**

**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.x | Pipeline Integrity Management - Bartow/Anclote Pipeline | $286,019 | $284,672 | $1,347 | 0% |
| | 4.x | Above Ground Tank Secondary Containment | 1,747,450 | 1,792,602 | (45,152) | -3% |
| | 5 | SO2/NOx Emissions Allowances | 1,279,248 | 1,351,895 | (72,647) | -5% |
| | 7.x | CAIR/CAMR | 800,444 | 837,763 | (37,319) | -4% |
| | 7.5 | Best Available Retrofit Technology (BART) | 0 | 0 | 0 | 0% |
| | 9 | Sea Turtle - Coastal Street Lighting | 1,372 | 1,538 | (166) | -11% |
| | 10.x | Underground Storage Tanks | 27,877 | 29,233 | (1,356) | -5% |
| | 11 | Modular Cooling Towers | 0 | 0 | 0 | 0% |
| | 11.1 | Crystal River Thermal Discharge Compliance Project | 6,019,823 | 5,994,976 | 24,847 | 0% |
| | 16 | National Pollutant Discharge Elimination System (NPDES) | 1,869,774 | 1,862,499 | 7,275 | 0% |
| | 17x | Mercury & Air Toxics Standards (MATS) | 19,523,407 | 18,783,264 | 740,143 | 4% |
| | 18 | Coal Combustion Residual (CCR) Rule | 57,703 | 0 | 57,703 | 100% |
| 2 | | Total Capital Investment Activities - Recoverable Costs | $31,613,117 | $30,938,442 | $674,675 | 2% |
| 3 | | Recoverable Costs Allocated to Energy | 20,973,173 | 20,222,911 | $750,262 | 4% |
| 4 | | Recoverable Costs Allocated to Demand | $10,639,944 | $10,715,531 | ($75,587) | -1% |

Notes:

Column (1) - End of Period Totals on Form 42-7E
Column (2) - 2015 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 2015 - December 2015**

**Capital Investment Projects-Recoverable Costs**
**(in Dollars)**

| Line | Description | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investment Projects - System (A) | | | | | | | | | | | | | |
| 3.1 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intermediate | $24,031 | $23,981 | $23,934 | $23,886 | $23,837 | $23,789 | 23,882 | $23,834 | $23,784 | $23,735 | $23,688 | $23,638 | $286,019 |
| 4.1 | Above Ground Tank Secondary Containment - Peaking | 119,125 | 118,842 | 118,558 | 118,274 | 117,989 | 117,706 | 118,077 | 117,791 | 117,502 | 117,217 | 116,928 | 116,643 | 1,414,652 |
| 4.2 | Above Ground Tank Secondary Containment - Base | 25,061 | 25,034 | 25,007 | 24,982 | 24,956 | 24,930 | 25,094 | 25,069 | 25,042 | 25,015 | 24,990 | 24,963 | 300,143 |
| 4.3 | Above Ground Tank Secondary Containment - Intermediate | 2,738 | 2,733 | 2,728 | 2,724 | 2,719 | 2,714 | 2,727 | 2,724 | 2,719 | 2,714 | 2,710 | 2,705 | 32,655 |
| 5 | SO2/NOX Emissions Allowances - Energy | 120,297 | 117,777 | 115,249 | 112,730 | 110,188 | 107,599 | 105,902 | 103,220 | 100,528 | 97,841 | 95,228 | 92,689 | 1,279,248 |
| 7.1 | CAIR/CAMR Anclote- Intermediate | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.2 | CAIR/CAMR - Peaking | 19,049 | 19,023 | 18,988 | 18,959 | 18,928 | 18,897 | 18,988 | 18,958 | 18,929 | 18,897 | 18,868 | 18,837 | 227,321 |
| 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 | 35,607 | 35,658 | 35,773 | 36,024 | 36,296 | 36,428 | 36,826 | 41,640 | 41,613 | 41,547 | 41,480 | 41,416 | 460,308 |
| 7.4 | CAIR/CAMR Crystal River AFUDC - Energy | 9,950 | 9,531 | 9,257 | 8,918 | 8,997 | 9,604 | 9,794 | 9,439 | 9,401 | 9,305 | 9,279 | 9,338 | 112,815 |
| 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 | 115 | 115 | 115 | 114 | 114 | 114 | 114 | 114 | 114 | 114 | 114 | 115 | 1,372 |
| 10.1 | Underground Storage Tanks - Base | 1,589 | 1,587 | 1,584 | 1,582 | 1,579 | 1,577 | 1,584 | 1,582 | 1,579 | 1,577 | 1,574 | 1,572 | 18,966 |
| 10.2 | Underground Storage Tanks - Intermediate | 750 | 748 | 747 | 745 | 743 | 742 | 743 | 742 | 741 | 738 | 737 | 735 | 8,911 |
| 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) (B) | 3,325 | 3,299 | 3,273 | 3,248 | 3,222 | 3,195 | 3,171 | 3,145 | 3,119 | 3,092 | 3,067 | 3,041 | 38,192 |
| 11.1 | Crystal River Thermal Discharge Compliance Project - Base (2012) (B) | 524,030 | 519,947 | 512,073 | 507,865 | 503,814 | 499,763 | 495,908 | 491,821 | 487,734 | 483,645 | 479,559 | 475,472 | 5,981,631 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Intermediate | 157,034 | 156,748 | 156,636 | 156,539 | 156,451 | 155,720 | 155,983 | 155,552 | 155,243 | 154,933 | 154,622 | 154,313 | 1,869,774 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 7,680 | 8,801 | 8,403 | 9,308 | 10,666 | 11,448 | 13,270 | 20,282 | 32,895 | 35,685 | 36,649 | 37,396 | 232,485 |
| 17.1 | Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy | 1,441,130 | 1,441,351 | 1,440,182 | 1,438,514 | 1,436,454 | 1,434,657 | 1,442,706 | 1,440,600 | 1,438,494 | 1,436,388 | 1,434,282 | 1,432,176 | 17,256,928 |
| 17.2 | Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy | 69,846 | 82,002 | 96,056 | 119,162 | 142,065 | 191,208 | 204,238 | 213,113 | 217,839 | 222,265 | 235,304 | 240,893 | 2,033,994 |
| 18 | Coal Combustion Residual (CCR) Rule | 0 | 0 | 0 | 0 | 0 | 0 | 431 | 3,241 | 7,557 | 11,872 | 17,315 | 17,287 | 57,703 |
| 2 | Total Investment Projects - Recoverable Costs | $2,561,356 | $2,567,176 | $2,568,563 | $2,583,574 | $2,599,018 | $2,640,091 | $2,659,438 | $2,672,867 | $2,684,833 | $2,686,580 | $2,696,394 | $2,693,229 | $31,613,117 |
| 3 | Recoverable Costs Allocated to Energy | 1,648,903 | 1,659,462 | 1,669,147 | 1,688,632 | 1,708,371 | 1,754,516 | 1,776,341 | 1,789,895 | 1,806,714 | 1,813,356 | 1,828,057 | 1,829,779 | 20,973,173 |
| | Recoverable Costs Allocated to Distribution Demand | 115 | 115 | 115 | 114 | 114 | 114 | 114 | 114 | 114 | 114 | 114 | 115 | 1,372 |
| 4 | Recoverable Costs Allocated to Demand - Production - Base | 65,582 | 65,578 | 65,637 | 65,836 | 66,053 | 66,130 | 66,675 | 71,436 | 71,353 | 71,231 | 71,111 | 70,992 | 817,609 |
| | Recoverable Costs Allocated to Demand - Production - Intermediate | 184,553 | 184,210 | 184,045 | 183,894 | 183,750 | 182,965 | 183,335 | 182,852 | 182,487 | 182,120 | 181,757 | 181,391 | 2,197,359 |
| | Recoverable Costs Allocated to Demand - Production - Peaking | 138,174 | 137,865 | 137,546 | 137,233 | 136,917 | 136,603 | 137,065 | 136,749 | 136,431 | 136,114 | 135,796 | 135,480 | 1,641,973 |
| | Recoverable Costs Allocated to Demand - Production - Base (2012) | 524,030 | 519,947 | 512,073 | 507,865 | 503,814 | 499,763 | 495,908 | 491,821 | 487,734 | 483,645 | 479,559 | 475,472 | 5,981,631 |
| 5 | Retail Energy Jurisdictional Factor | 0.96920 | 0.97990 | 0.97660 | 0.96410 | 0.94750 | 0.95600 | 0.97335 | 0.97071 | 0.96978 | 0.97063 | 0.97372 | 0.98187 | |
| | 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 (C) | 1,598,116 | 1,626,106 | 1,630,089 | 1,628,010 | 1,618,681 | 1,677,318 | 1,729,005 | 1,737,475 | 1,752,111 | 1,760,101 | 1,780,006 | 1,796,604 | 20,333,622 |
| | Jurisdictional Demand Recoverable Costs - Distribution (C) | 114 | 114 | 114 | 113 | 113 | 113 | 113 | 113 | 113 | 113 | 113 | 114 | 1,366 |
| 8 | Jurisdictional Demand Recoverable Costs - Production - Base (D) | 60,915 | 60,912 | 60,967 | 61,151 | 61,353 | 61,424 | 61,931 | 66,353 | 66,276 | 66,163 | 66,051 | 65,941 | 759,436 |
| | Jurisdictional Demand Recoverable Costs - Production - Intermediate (D) | 134,176 | 133,926 | 133,806 | 133,696 | 133,592 | 133,021 | 133,290 | 132,939 | 132,674 | 132,407 | 132,143 | 131,877 | 1,597,546 |
| | Jurisdictional Demand Recoverable Costs - Production - Peaking (D) | 132,542 | 132,246 | 131,940 | 131,639 | 131,336 | 131,035 | 131,478 | 131,175 | 130,870 | 130,566 | 130,261 | 129,958 | 1,575,046 |
| | Jurisdictional Demand Recoverable Costs - Production - Base (2012) (D) | 480,446 | 476,703 | 469,484 | 465,626 | 461,912 | 458,198 | 454,663 | 450,916 | 447,169 | 443,420 | 439,674 | 435,927 | 5,484,139 |
| 9 | Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8) | $2,406,310 | $2,430,007 | $2,426,400 | $2,420,237 | $2,406,987 | $2,461,109 | $2,510,481 | $2,518,972 | $2,529,213 | $2,532,769 | $2,548,249 | $2,560,420 | $29,751,155 |

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) The POD project spend and revenue requirements associated with 2012 and prior activities are jurisdictionalized using the 2012 Production Base Demand separation factor.
The revenue requirements associated with the 2013 period and after are jurisdictionalized using the 2013 Production Base Demand separation factor.
(C) Line 3 x Line 5
(D) Line 4 x Line 6

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Calculation of Actual / Estimated Amount**
**January 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | 2,614,704 | |
| 3 | Less: Accumulated Depreciation | (709,777) | (715,421) | (721,065) | (726,709) | (732,353) | (737,997) | (743,641) | (749,285) | (754,929) | (760,573) | (766,217) | (771,861) | (777,505) | |
| 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) | $1,904,928 | $1,899,284 | $1,893,640 | $1,887,996 | $1,882,352 | $1,876,708 | $1,871,064 | $1,865,420 | $1,859,776 | $1,854,132 | $1,848,488 | $1,842,844 | $1,837,200 | |
| 6 | Average Net Investment | | $1,902,106 | $1,896,462 | $1,890,818 | $1,885,174 | $1,879,530 | $1,873,886 | $1,868,242 | $1,862,598 | $1,856,954 | $1,851,310 | $1,845,666 | $1,840,022 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 3,170 | 3,160 | 3,152 | 3,142 | 3,133 | 3,124 | 3,155 | 3,145 | 3,135 | 3,126 | 3,116 | 3,107 | 37,665 |
| | b. Equity Component Grossed Up For Taxes | | 13,110 | 13,070 | 13,031 | 12,993 | 12,953 | 12,914 | 12,976 | 12,938 | 12,898 | 12,858 | 12,821 | 12,780 | 155,342 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 67,728 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/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) | | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 25,284 |
| | e. Other (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $24,031 | $23,981 | $23,934 | $23,886 | $23,837 | $23,789 | $23,882 | $23,834 | $23,784 | $23,735 | $23,688 | $23,638 | 286,019 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 24,031 | 23,981 | 23,934 | 23,886 | 23,837 | 23,789 | 23,882 | 23,834 | 23,784 | 23,735 | 23,688 | 23,638 | 286,019 |
| 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) | | 17,471 | 17,435 | 17,401 | 17,366 | 17,330 | 17,295 | 17,363 | 17,328 | 17,292 | 17,256 | 17,222 | 17,186 | 207,944 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $17,471 | $17,435 | $17,401 | $17,366 | $17,330 | $17,295 | $17,363 | $17,328 | $17,292 | $17,256 | $17,222 | $17,186 | $207,944 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | 11,301,803 | |
| 3 | Less: Accumulated Depreciation | (2,407,191) | (2,440,418) | (2,473,645) | (2,506,872) | (2,540,099) | (2,573,326) | (2,606,553) | (2,639,780) | (2,673,007) | (2,706,234) | (2,739,461) | (2,772,688) | (2,805,915) | |
| 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) | $8,894,613 | $8,861,386 | $8,828,159 | $8,794,932 | $8,761,705 | $8,728,478 | $8,695,251 | $8,662,024 | $8,628,797 | $8,595,570 | $8,562,343 | $8,529,116 | $8,495,889 | |
| 6 | Average Net Investment | | $8,877,999 | $8,844,772 | $8,811,545 | $8,778,318 | $8,745,091 | $8,711,864 | $8,678,637 | $8,645,410 | $8,612,183 | $8,578,956 | $8,545,729 | $8,512,502 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 14,794 | 14,740 | 14,686 | 14,630 | 14,575 | 14,520 | 14,653 | 14,599 | 14,541 | 14,484 | 14,428 | 14,374 | 175,024 |
| | b. Equity Component Grossed Up For Taxes | | 61,187 | 60,958 | 60,728 | 60,500 | 60,270 | 60,042 | 60,280 | 60,048 | 59,817 | 59,589 | 59,356 | 59,125 | 721,900 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 398,724 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/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) | | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 119,004 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $119,125 | $118,842 | $118,558 | $118,274 | $117,989 | $117,706 | $118,077 | $117,791 | $117,502 | $117,217 | $116,928 | $116,643 | 1,414,652 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 119,125 | 118,842 | 118,558 | 118,274 | 117,989 | 117,706 | 118,077 | 117,791 | 117,502 | 117,217 | 116,928 | 116,643 | 1,414,652 |
| 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) | | 114,269 | 113,998 | 113,726 | 113,453 | 113,180 | 112,908 | 113,264 | 112,990 | 112,713 | 112,439 | 112,162 | 111,889 | 1,356,991 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $114,269 | $113,998 | $113,726 | $113,453 | $113,180 | $112,908 | $113,264 | $112,990 | $112,713 | $112,439 | $112,162 | $111,889 | $1,356,991 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | 136,385 | 133,353 | 130,321 | 127,289 | 124,257 | 121,225 | 118,193 | 115,161 | 112,129 | 109,097 | 106,065 | 103,033 | 100,001 | |
| 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) | $2,535,424 | $2,532,392 | $2,529,360 | $2,526,328 | $2,523,296 | $2,520,264 | $2,517,232 | $2,514,200 | $2,511,168 | $2,508,136 | $2,505,104 | $2,502,072 | $2,499,040 | |
| 6 | Average Net Investment | | $2,533,908 | $2,530,876 | $2,527,844 | $2,524,812 | $2,521,780 | $2,518,748 | $2,515,716 | $2,512,684 | $2,509,652 | $2,506,620 | $2,503,588 | $2,500,556 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 4,224 | 4,218 | 4,213 | 4,208 | 4,203 | 4,198 | 4,248 | 4,243 | 4,238 | 4,232 | 4,227 | 4,222 | 50,674 |
| | b. Equity Component Grossed Up For Taxes | | 17,464 | 17,443 | 17,421 | 17,401 | 17,380 | 17,359 | 17,473 | 17,453 | 17,431 | 17,410 | 17,390 | 17,368 | 208,993 |
| | 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) | | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 4,092 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $25,061 | $25,034 | $25,007 | $24,982 | $24,956 | $24,930 | $25,094 | $25,069 | $25,042 | $25,015 | $24,990 | $24,963 | 300,143 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 25,061 | 25,034 | 25,007 | 24,982 | 24,956 | 24,930 | 25,094 | 25,069 | 25,042 | 25,015 | 24,990 | 24,963 | 300,143 |
| 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) | | 23,278 | 23,253 | 23,228 | 23,205 | 23,180 | 23,156 | 23,309 | 23,285 | 23,260 | 23,235 | 23,212 | 23,187 | 278,788 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $23,278 | $23,253 | $23,228 | $23,205 | $23,180 | $23,156 | $23,309 | $23,285 | $23,260 | $23,235 | $23,212 | $23,187 | $278,788 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | (53,886) | (54,411) | (54,936) | (55,461) | (55,986) | (56,511) | (57,036) | (57,561) | (58,086) | (58,611) | (59,136) | (59,661) | (60,186) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | $236,412 | $235,887 | $235,362 | $234,837 | $234,312 | $233,787 | $233,262 | $232,737 | $232,212 | $231,687 | $231,162 | $230,637 | $230,112 | |
| 6 | Average Net Investment | | $236,149 | $235,624 | $235,099 | $234,574 | $234,049 | $233,524 | $232,999 | $232,474 | $231,949 | $231,424 | $230,899 | $230,374 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 394 | 393 | 392 | 391 | 390 | 389 | 393 | 393 | 392 | 391 | 390 | 389 | 4,697 |
| | b. Equity Component Grossed Up For Taxes | | 1,628 | 1,624 | 1,620 | 1,617 | 1,613 | 1,609 | 1,618 | 1,615 | 1,611 | 1,607 | 1,604 | 1,600 | 19,366 |
| | 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) | | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 2,292 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $2,738 | $2,733 | $2,728 | $2,724 | $2,719 | $2,714 | $2,727 | $2,724 | $2,719 | $2,714 | $2,710 | $2,705 | 32,655 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 2,738 | 2,733 | 2,728 | 2,724 | 2,719 | 2,714 | 2,727 | 2,724 | 2,719 | 2,714 | 2,710 | 2,705 | 32,655 |
| 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) | | 1,991 | 1,987 | 1,983 | 1,980 | 1,977 | 1,973 | 1,983 | 1,980 | 1,977 | 1,973 | 1,970 | 1,967 | 23,741 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $1,991 | $1,987 | $1,983 | $1,980 | $1,977 | $1,973 | $1,983 | $1,980 | $1,977 | $1,973 | $1,970 | $1,967 | $23,741 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2015 - December 2015**

**SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)**
**(in Dollars)**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | | |
| | a. 0158150 $SO_2$ Emission Allowance Inventory | | | $3,551,712 | $3,541,054 | $3,528,463 | $3,518,291 | $3,507,286 | $3,489,908 | $3,468,236 | $3,442,156 | $3,412,724 | $3,384,575 | $3,355,889 | $3,345,009 | $3,333,608 | $3,333,608 |
| | b. 0254020 Auctioned $SO_2$ Allowance | | | (238,548) | (219,021) | (199,495) | (179,969) | (160,378) | (140,836) | (121,293) | (101,751) | (82,209) | (62,666) | (43,124) | (23,581) | (4,039) | (4,039) |
| | c. 0158170 NOx Emission Allowance Inventory | | | 578,825 | 1,981 | 1,981 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Other (A) | | | 10,310,625 | 10,585,040 | 10,282,610 | 9,980,180 | 9,677,751 | 9,375,321 | 9,072,891 | 8,770,461 | 8,468,032 | 8,165,602 | 7,863,172 | 7,560,743 | 7,258,313 | 7,258,313 |
| 2 | Total Working Capital | | | $14,202,614 | $13,909,053 | $13,613,559 | $13,318,503 | $13,024,658 | $12,724,393 | $12,419,834 | $12,110,867 | $11,798,547 | $11,487,511 | $11,175,937 | $10,882,170 | $10,587,882 | $10,587,882 |
| 3 | Average Net Investment | | | | $14,055,834 | $13,761,306 | $13,466,031 | $13,171,580 | $12,874,526 | $12,572,113 | $12,265,350 | $11,954,707 | $11,643,029 | $11,331,724 | $11,029,054 | $10,735,026 | |
| 4 | Return on Average Net Working Capital Balance (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% | 2.03% | | 23,426 | 22,936 | 22,443 | 21,953 | 21,458 | 20,954 | 20,710 | 20,186 | 19,659 | 19,134 | 18,623 | 18,126 | 249,608 |
| | b. Equity Component Grossed Up For Taxes | 8.27% | 8.33% | | 96,871 | 94,841 | 92,806 | 90,777 | 88,730 | 86,645 | 85,192 | 83,034 | 80,869 | 78,707 | 76,605 | 74,563 | 1,029,640 |
| 5 | Total Return Component (C) | | | | $120,297 | $117,777 | $115,249 | $112,730 | $110,188 | $107,599 | $105,902 | $103,220 | $100,528 | $97,841 | $95,228 | $92,689 | 1,279,248 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | | |
| | a. 0509030 $SO_2$ Allowance Expense | | | | $10,658 | $12,591 | $10,172 | $11,005 | $17,378 | $21,672 | $26,080 | $29,433 | $28,149 | $28,686 | $10,880 | $11,401 | 218,104 |
| | b. 0407426 Amortization Expense | | | | (19,526) | (19,526) | (19,526) | (19,590) | (19,542) | (19,542) | (19,542) | (19,542) | (19,542) | (19,542) | (19,542) | (19,542) | (234,509) |
| | c. 0 509212 NOx Allowance Expense | | | | 0 | 0 | 1,981 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,981 |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Net Expense (D) | | | | (8,868) | (6,935) | (7,374) | (8,585) | (2,165) | 2,130 | 6,537 | 9,890 | 8,606 | 9,144 | (8,663) | (8,142) | (14,424) |
| 8 | Amortization of NOx CAIR Emission Allowances (A) | | | | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 9 | Total System Recoverable Expenses (Lines 5 + 7) | | | | $413,858 | $413,271 | $410,305 | $406,575 | $410,453 | $412,158 | $414,869 | $415,540 | $411,564 | $409,415 | $388,995 | $386,977 | 4,893,980 |
| | a. Recoverable Costs Allocated to Energy | | | | 111,429 | 110,842 | 107,875 | 104,145 | 108,023 | 109,729 | 112,439 | 113,110 | 109,134 | 106,985 | 86,565 | 84,547 | 1,264,824 |
| | b. Recoverable Costs Allocated to Energy - NOx CAIR Emisssion Allowances (A) | | | | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 10 | Energy Jurisdictional Factor | | | | 0.96920 | 0.97990 | 0.97660 | 0.96410 | 0.94750 | 0.95600 | 0.97335 | 0.97071 | 0.96978 | 0.97063 | 0.97372 | 0.98187 | |
| 11 | NOx Regulatory Asset Energy Factor (12/2014) (A) | | | | 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 (E) | | | | $107,997 | $108,614 | $105,351 | $100,406 | $102,352 | $104,901 | $109,443 | $109,798 | $105,836 | $103,843 | $84,290 | $83,014 | 1,225,844 |
| 13 | NOx CAIR Emission Allowances Recoverable Costs (A) | | | | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | | | $ 404,166 | $ 404,783 | $ 401,520 | $ 396,575 | $ 398,522 | $ 401,070 | $ 405,612 | $ 405,967 | $ 402,005 | $ 400,012 | $ 380,459 | $ 379,184 | $ 4,779,877 |

Notes:

(A) $10,889,450 ($578,825 Line 1c Beg Bal + $10,310,625 Line 1d Beg Bal) unusable NOx emission allowances due expiration of Clean Air Interstate Rule (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-11-0553-FOF-EI.

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) Line 5 is reported on Capital Schedule

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

(E) Line 9 x Line 10

(F) Line 8b x Line 10

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Calculation of Actual / Estimated Amount**
**January 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
Page 14 of 28

**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | 1,936,108 | |
| 3 | Less: Accumulated Depreciation | (303,816) | (307,366) | (310,916) | (314,466) | (318,016) | (321,566) | (325,116) | (328,666) | (332,216) | (335,766) | (339,316) | (342,866) | (346,416) | |
| 4 | CWIP - Non-Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $1,632,292 | $1,628,742 | $1,625,192 | $1,621,642 | $1,618,092 | $1,614,542 | $1,610,992 | $1,607,442 | $1,603,892 | $1,600,342 | $1,596,792 | $1,593,242 | $1,589,692 | |
| 6 | Average Net Investment | | $1,630,517 | $1,626,967 | $1,623,417 | $1,619,867 | $1,616,317 | $1,612,767 | $1,609,217 | $1,605,667 | $1,602,117 | $1,598,567 | $1,595,017 | $1,591,467 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 2,717 | 2,714 | 2,705 | 2,700 | 2,694 | 2,688 | 2,717 | 2,711 | 2,706 | 2,699 | 2,693 | 2,688 | 32,432 |
| | b. Equity Component Grossed Up For Taxes | | 11,237 | 11,214 | 11,188 | 11,164 | 11,139 | 11,114 | 11,176 | 11,152 | 11,128 | 11,103 | 11,080 | 11,054 | 133,749 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 42,600 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/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) | | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 18,540 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $19,049 | $19,023 | $18,988 | $18,959 | $18,928 | $18,897 | $18,988 | $18,958 | $18,929 | $18,897 | $18,868 | $18,837 | 227,321 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 19,049 | 19,023 | 18,988 | 18,959 | 18,928 | 18,897 | 18,988 | 18,958 | 18,929 | 18,897 | 18,868 | 18,837 | 227,321 |
| 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) | | 18,273 | 18,248 | 18,214 | 18,186 | 18,156 | 18,127 | 18,214 | 18,185 | 18,157 | 18,127 | 18,099 | 18,069 | 218,055 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $18,273 | $18,248 | $18,214 | $18,186 | $18,156 | $18,127 | $18,214 | $18,185 | $18,157 | $18,127 | $18,099 | $18,069 | $218,055 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $6,058 | $12,003 | $21,452 | $43,572 | $26,097 | $11,157 | $20,000 | $8,843 | $0 | $0 | $0 | $0 | $149,183 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 2,144,255 | 8,843 | 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 | $1,797,770 | 1,797,770 | 1,797,770 | 1,797,770 | 1,797,770 | 1,797,770 | 1,797,770 | 3,942,024 | 3,950,867 | 3,950,867 | 3,950,867 | 3,950,867 | 3,950,867 | |
| 3 | Less: Accumulated Depreciation | (45,950) | (49,147) | (52,344) | (55,541) | (58,738) | (61,935) | (65,132) | (68,329) | (75,957) | (83,585) | (91,213) | (98,841) | (106,469) | |
| 4 | CWIP - Non-Interest Bearing | 2,003,915 | 2,009,973 | 2,021,976 | 2,043,427 | 2,087,000 | 2,113,097 | 2,124,255 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $3,755,735 | $3,758,596 | $3,767,402 | $3,785,657 | $3,826,032 | $3,848,933 | $3,856,893 | $3,873,696 | $3,874,911 | $3,867,283 | $3,859,655 | $3,852,027 | $3,844,399 | |
| 6 | Average Net Investment | | $3,757,165 | $3,762,999 | $3,776,529 | $3,805,844 | $3,837,482 | $3,852,913 | $3,865,294 | $3,874,303 | $3,871,097 | $3,863,469 | $3,855,841 | $3,848,213 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 6,261 | 6,272 | 6,294 | 6,343 | 6,396 | 6,422 | 6,527 | 6,541 | 6,536 | 6,524 | 6,510 | 6,498 | 77,124 |
| | b. Equity Component Grossed Up For Taxes | | 25,894 | 25,934 | 26,027 | 26,229 | 26,448 | 26,554 | 26,847 | 26,910 | 26,888 | 26,834 | 26,781 | 26,729 | 318,075 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 60,519 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/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) | | 255 | 255 | 255 | 255 | 255 | 255 | 255 | 561 | 561 | 561 | 561 | 561 | 4,590 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $35,607 | $35,658 | $35,773 | $36,024 | $36,296 | $36,428 | $36,826 | $41,640 | $41,613 | $41,547 | $41,480 | $41,416 | 460,308 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 35,607 | 35,658 | 35,773 | 36,024 | 36,296 | 36,428 | 36,826 | 41,640 | 41,613 | 41,547 | 41,480 | 41,416 | 460,308 |
| 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) | | 33,074 | 33,121 | 33,228 | 33,461 | 33,714 | 33,836 | 34,206 | 38,677 | 38,652 | 38,591 | 38,529 | 38,469 | 427,557 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $33,074 | $33,121 | $33,228 | $33,461 | $33,714 | $33,836 | $34,206 | $38,677 | $38,652 | $38,591 | $38,529 | $38,469 | $427,557 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | | |
| | a. 0154401 Ammonia Inventory | | | $358,058 | $213,381 | $145,932 | $76,722 | $185,870 | $219,806 | $269,526 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 |
| | b. 0154200 Limestone Inventory | | | 853,417 | 900,378 | 967,621 | 972,915 | 848,430 | 848,430 | 906,551 | 907,388 | 908,556 | 898,712 | 886,345 | 892,664 | 900,036 | 900,036 |
| 2 | Total Working Capital | | | $1,211,475 | $1,113,760 | $1,113,553 | $1,049,637 | $1,034,300 | $1,068,236 | $1,176,077 | $1,092,594 | $1,093,762 | $1,083,918 | $1,071,551 | $1,077,870 | $1,085,242 | 1,085,242 |
| 3 | Average Net Investment | | | | 1,162,618 | 1,113,656 | 1,081,595 | 1,041,969 | 1,051,268 | 1,122,157 | 1,134,336 | 1,093,178 | 1,088,840 | 1,077,734 | 1,074,710 | 1,081,556 | |
| 4 | Return on Average Net Working Capital Balance (A) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% | 2.03% | | 1,938 | 1,856 | 1,803 | 1,737 | 1,752 | 1,870 | 1,915 | 1,846 | 1,839 | 1,820 | 1,815 | 1,826 | $22,016 |
| | b. Equity Component Grossed Up For Taxes | 8.27% | 8.33% | | 8,013 | 7,675 | 7,454 | 7,181 | 7,245 | 7,734 | 7,879 | 7,593 | 7,563 | 7,486 | 7,465 | 7,512 | 90,799 |
| 5 | Total Return Component (B) | | | | 9,950 | 9,531 | 9,257 | 8,918 | 8,997 | 9,604 | 9,794 | 9,439 | 9,401 | 9,305 | 9,279 | 9,338 | 112,815 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | | |
| | a. 0502030 Ammonia Expense | | | | 336,452 | 371,240 | 632,960 | 416,443 | 397,689 | 510,591 | 442,256 | 443,771 | 427,726 | 452,345 | 291,840 | 427,905 | 5,151,217 |
| | b. 0502040 Limestone Expense | | | | 224,414 | 276,877 | 461,037 | 487,554 | 547,044 | 432,768 | 414,987 | 420,796 | 410,375 | 436,850 | 282,783 | 416,914 | 4,812,400 |
| | c. 0502050 Dibasic Acid Expense | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 22,000 | 0 | 0 | 22,000 |
| | d. 0502070 Gypsum Disposal/Sale | | | | 44,201 | 116,724 | (30,496) | 70,071 | (74,756) | (474,028) | (19,000) | 207,389 | 207,389 | 207,389 | 207,389 | 207,389 | 669,660 |
| | b. 0502040 Hydrated Lime Expense | | | | 136,075 | 162,321 | 299,567 | 301,583 | 122,658 | 303,539 | 381,383 | 383,927 | 369,201 | 390,389 | 245,884 | 370,010 | 3,466,536 |
| | f. 0502300 Caustic Expense | | | | 720 | 3,186 | 14,024 | 0 | 17,140 | 20,257 | 15,000 | 15,000 | 15,000 | 15,000 | 15,000 | 15,000 | 145,329 |
| 7 | Net Expense (C) | | | | 741,862 | 930,348 | 1,377,092 | 1,275,650 | 1,009,776 | 793,128 | 1,234,626 | 1,470,883 | 1,429,691 | 1,523,973 | 1,042,896 | 1,437,217 | 14,267,141 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | | | $751,812 | $939,879 | $1,386,349 | $1,284,568 | $1,018,773 | $802,732 | $1,244,420 | $1,480,322 | $1,439,092 | $1,533,278 | $1,052,175 | $1,446,556 | 14,379,956 |
| | a. Recoverable Costs Allocated to Energy | | | | 751,812 | 939,879 | 1,386,349 | 1,284,568 | 1,018,773 | 802,732 | 1,244,420 | 1,480,322 | 1,439,092 | 1,533,278 | 1,052,175 | 1,446,556 | 14,379,956 |
| | b. Recoverable Costs Allocated to Demand | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Energy Jurisdictional Factor | | | | 0.96920 | 0.97990 | 0.97660 | 0.96410 | 0.94750 | 0.95600 | 0.97335 | 0.97071 | 0.96978 | 0.97063 | 0.97372 | 0.98187 | |
| 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) | | | | 728,657 | 920,988 | 1,353,908 | 1,238,452 | 965,288 | 767,412 | 1,211,259 | 1,436,968 | 1,395,599 | 1,488,248 | 1,024,518 | 1,420,328 | 13,951,624 |
| 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) | | | | $ 728,657 | $ 920,988 | $ 1,353,908 | $ 1,238,452 | $ 965,288 | $ 767,412 | $ 1,211,259 | $ 1,436,968 | $ 1,395,599 | $ 1,488,248 | $ 1,024,518 | $ 1,420,328 | $ 13,951,624 |

Notes:

(A) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: BART (Project 7.5)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | ($0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 3 | Less: Accumulated Depreciation | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | ($0) | |
| 6 | Average Net Investment | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% | 2.03% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Equity Component Grossed Up For Taxes | 8.27% | 8.33% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Other (G) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.5600% | | | 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) | 0.008573 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | | 0.96920 | 0.97990 | 0.97660 | 0.96410 | 0.94750 | 0.95600 | 0.97335 | 0.97071 | 0.96978 | 0.97063 | 0.97372 | 0.98187 | |
| 11 | Demand Jurisdictional Factor | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13 | Retail Demand-Related Recoverable Costs (F) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-10-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2014 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

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Duke Energy Florida
Witness: T. G. Foster
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**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Calculation of Actual / Estimated Amount**
**January 2015 - December 2015**

**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $150 | $150 | $300 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | | | (2,307) | (2,336) | (2,365) | (2,394) | (2,423) | (2,452) | (2,481) | (2,510) | (2,539) | (2,568) | (2,597) | (2,626) | (2,655) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 150 | 300 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $9,017 | $8,988 | $8,959 | $8,930 | $8,901 | $8,872 | $8,843 | $8,814 | $8,785 | $8,756 | $8,727 | $8,848 | $8,969 | |
| 6 | Average Net Investment | | | | $9,002 | $8,973 | $8,944 | $8,915 | $8,886 | $8,857 | $8,828 | $8,799 | $8,770 | $8,741 | $8,787 | $8,908 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% | 2.03% | | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 180 |
| | b. Equity Component Grossed Up For Taxes | 8.27% | 8.33% | | 62 | 62 | 62 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 62 | 736 |
| | 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) | 0.009035 | | | 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) | | | | $115 | $115 | $115 | $114 | $114 | $114 | $114 | $114 | $114 | $114 | $114 | $115 | 1,372 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $115 | $115 | $115 | $114 | $114 | $114 | $114 | $114 | $114 | $114 | $114 | $115 | 1,372 |
| 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) | | | | 114 | 114 | 114 | 113 | 113 | 113 | 113 | 113 | 113 | 113 | 113 | 114 | 1,366 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $114 | $114 | $114 | $113 | $113 | $113 | $113 | $113 | $113 | $113 | $113 | $114 | $1,366 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-10-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2014 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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | | | (31,792) | (32,088) | (32,384) | (32,680) | (32,976) | (33,272) | (33,568) | (33,864) | (34,160) | (34,456) | (34,752) | (35,048) | (35,344) | |
| 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) | | | $137,149 | $136,853 | $136,557 | $136,261 | $135,965 | $135,669 | $135,373 | $135,077 | $134,781 | $134,485 | $134,189 | $133,893 | $133,597 | |
| 6 | Average Net Investment | | | | $137,001 | $136,705 | $136,409 | $136,113 | $135,817 | $135,521 | $135,225 | $134,929 | $134,633 | $134,337 | $134,041 | $133,745 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% | 2.03% | | 228 | 228 | 227 | 227 | 226 | 226 | 228 | 228 | 227 | 227 | 226 | 226 | 2,724 |
| | b. Equity Component Grossed Up For Taxes | 8.27% | 8.33% | | 944 | 942 | 940 | 938 | 936 | 934 | 939 | 937 | 935 | 933 | 931 | 929 | 11,238 |
| | 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) | | | | $1,589 | $1,587 | $1,584 | $1,582 | $1,579 | $1,577 | $1,584 | $1,582 | $1,579 | $1,577 | $1,574 | $1,572 | 18,966 |
| | 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 | | | | $1,589 | $1,587 | $1,584 | $1,582 | $1,579 | $1,577 | $1,584 | $1,582 | $1,579 | $1,577 | $1,574 | $1,572 | 18,966 |
| 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) | | | | 1,476 | 1,474 | 1,471 | 1,469 | 1,467 | 1,465 | 1,471 | 1,469 | 1,467 | 1,465 | 1,462 | 1,460 | 17,617 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $1,476 | $1,474 | $1,471 | $1,469 | $1,467 | $1,465 | $1,471 | $1,469 | $1,467 | $1,465 | $1,462 | $1,460 | $17,617 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | | | (19,349) | (19,552) | (19,755) | (19,958) | (20,161) | (20,364) | (20,567) | (20,770) | (20,973) | (21,176) | (21,379) | (21,582) | (21,785) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $56,657 | $56,454 | $56,251 | $56,048 | $55,845 | $55,642 | $55,439 | $55,236 | $55,033 | $54,830 | $54,627 | $54,424 | $54,221 | |
| 6 | Average Net Investment | | | | $56,556 | $56,353 | $56,150 | $55,947 | $55,744 | $55,541 | $55,338 | $55,135 | $54,932 | $54,729 | $54,526 | $54,323 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% | 2.03% | | 94 | 94 | 94 | 93 | 93 | 93 | 93 | 93 | 93 | 92 | 92 | 92 | 1,116 |
| | b. Equity Component Grossed Up For Taxes | 8.27% | 8.33% | | 390 | 388 | 387 | 386 | 384 | 383 | 384 | 383 | 382 | 380 | 379 | 377 | 4,603 |
| | 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) | | | | $750 | $748 | $747 | $745 | $743 | $742 | $743 | $742 | $741 | $738 | $737 | $735 | 8,911 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $750 | $748 | $747 | $745 | $743 | $742 | $743 | $742 | $741 | $738 | $737 | $735 | 8,911 |
| 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) | | | | 545 | 544 | 543 | 542 | 540 | 539 | 540 | 539 | 539 | 537 | 536 | 534 | 6,479 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $545 | $544 | $543 | $542 | $540 | $539 | $540 | $539 | $539 | $537 | $536 | $534 | $6,479 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: CRYSTAL RIVER THERMAL DISCHARGE COMPLIANCE PROJECT - AFUDC - Base (Project 11.1) - 2012 and Prior Year Spend**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | (36,519) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Regulatory Asset Balance | $5,724,328 | 5,724,328 | 5,247,301 | 4,733,754 | 4,260,379 | 3,787,003 | 3,313,628 | 2,840,253 | 2,366,877 | 1,893,502 | 1,420,126 | 946,751 | 473,375 | |
| 3 | Less: Amortization (B) | 0 | (477,027) | (477,027) | (473,375) | (473,375) | (473,375) | (473,375) | (473,375) | (473,375) | (473,375) | (473,375) | (473,375) | (473,375) | |
| 4 | CWIP - AFUDC Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $5,724,328 | $5,247,301 | $4,770,273 | $4,260,379 | $3,787,003 | $3,313,628 | $2,840,253 | $2,366,877 | $1,893,502 | $1,420,126 | $946,751 | $473,375 | ($0) | |
| 6 | Average Net Investment | | $5,485,814 | $5,008,787 | $4,515,326 | $4,023,691 | $3,550,316 | $3,076,940 | $2,603,565 | $2,130,189 | $1,656,814 | $1,183,439 | $710,063 | $236,688 | |
| 7 | Return on Average Net Investment (C) | | | | | | | | | | | | | | |
| | a. Debt Component | | 9,143 | 8,348 | 7,526 | 6,706 | 5,917 | 5,129 | 4,396 | 3,597 | 2,798 | 1,998 | 1,199 | 400 | 57,157 |
| | b. Equity Component Grossed Up For Taxes | | 37,808 | 34,520 | 31,119 | 27,731 | 24,469 | 21,206 | 18,084 | 14,796 | 11,508 | 8,219 | 4,932 | 1,644 | 236,036 |
| | c. Other | | 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 (B) | | 477,027 | 477,027 | 473,375 | 473,375 | 473,375 | 473,375 | 473,375 | 473,375 | 473,375 | 473,375 | 473,375 | 473,375 | 5,687,809 |
| | c. Dismantlement | | N/A | N/A | N/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) | | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 625 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $524,030 | $519,947 | $512,073 | $507,865 | $503,814 | $499,763 | $495,908 | $491,821 | $487,734 | $483,645 | $479,559 | $475,472 | 5,981,631 |
| | a. Recoverable Costs Allocated to Demand (2012) | | 524,030 | 519,947 | 512,073 | 507,865 | 503,814 | 499,763 | 495,908 | 491,821 | 487,734 | 483,645 | 479,559 | 475,472 | 5,981,631 |
| | b. Recoverable Costs Allocated to Demand (2013) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Demand Jurisdictional Factor - Production (Base) (2012) (E) | | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | |
| 11 | Demand Jurisdictional Factor - Production (Base) (2013) (E) | | 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 Demand-Related Recoverable Costs (2012) (F) | | $480,446 | $476,703 | $469,484 | $465,626 | $461,912 | $458,198 | $454,663 | $450,916 | $447,169 | $443,420 | $439,674 | $435,927 | $5,484,138 |
| 13 | Retail Demand-Related Recoverable Costs (2013) (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $480,446 | $476,703 | $469,484 | $465,626 | $461,912 | $458,198 | $454,663 | $450,916 | $447,169 | $443,420 | $439,674 | $435,927 | $5,484,138 |

Notes:

(A) N/A

(B) Investment amortized over three years in accordance with Order No. PSC-13-0381-PAA-EI.

(C) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(D) Property taxes calculated in CR Thermal Discharge Project 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 2014 Effective Tax Rate on original cost.

(E) The POD project spend and revenue requirements associated with 2012 and prior activities are jurisdictionalized using the 2012 Production Base Demand separation factor. The revenue requirements associated with the 2013 period and after are jurisdictionalized using the 2013 Production Base Demand separation factor.

(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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: CRYSTAL RIVER THERMAL DISCHARGE COMPLIANCE PROJECT - AFUDC - Base (Project 11.1) - Post 2012 Spend**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | Regulatory Asset Balance | $36,319 | 36,319 | 33,292 | 30,266 | 27,239 | 24,213 | 21,186 | 18,159 | 15,133 | 12,106 | 9,080 | 6,053 | 3,027 | |
| 3 | Less: Amortization (B) | 0 | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | (3,027) | |
| 4 | CWIP - AFUDC Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $36,319 | $33,292 | $30,266 | $27,239 | $24,213 | $21,186 | $18,159 | $15,133 | $12,106 | $9,080 | $6,053 | $3,027 | ($0) | |
| 6 | Average Net Investment | | $34,806 | $31,779 | $28,752 | $25,726 | $22,699 | $19,673 | $16,646 | $13,620 | $10,593 | $7,566 | $4,540 | $1,513 | |
| 7 | Return on Average Net Investment (C) | | | | | | | | | | | | | | |
| | a. Debt Component | | 58 | 53 | 48 | 43 | 38 | 32 | 28 | 23 | 18 | 12 | 8 | 3 | 364 |
| | b. Equity Component Grossed Up For Taxes | | 240 | 219 | 198 | 178 | 157 | 136 | 116 | 95 | 74 | 53 | 32 | 11 | 1,509 |
| | c. Other | | 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 (B) | | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 3,027 | 36,319 |
| | c. Dismantlement | | N/A | N/A | N/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 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $3,325 | $3,299 | $3,273 | $3,248 | $3,222 | $3,195 | $3,171 | $3,145 | $3,119 | $3,092 | $3,067 | $3,041 | 38,192 |
| | a. Recoverable Costs Allocated to Demand (2012) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand (2013) | | $3,325 | $3,299 | $3,273 | $3,248 | $3,222 | $3,195 | $3,171 | $3,145 | $3,119 | $3,092 | $3,067 | $3,041 | 38,192 |
| 10 | Demand Jurisdictional Factor - Production (Base) (2012) (E) | | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | 0.91683 | |
| 11 | Demand Jurisdictional Factor - Production (Base) (2013) (E) | | 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 Demand-Related Recoverable Costs (2012) (F) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13 | Retail Demand-Related Recoverable Costs (2013) (G) | | $3,088 | $3,064 | $3,040 | $3,017 | $2,992 | $2,967 | $2,945 | $2,921 | $2,897 | $2,872 | $2,848 | $2,824 | 35,475 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $3,088 | $3,064 | $3,040 | $3,017 | $2,992 | $2,967 | $2,945 | $2,921 | $2,897 | $2,872 | $2,848 | $2,824 | $35,475 |

Notes:

(A) N/A

(B) Investment amortized over three years in accordance with Order No. PSC-13-0381-PAA-EI.

(C) Jan - Jun 2014 Line 6 x 10.39% x 1/12. Jul - Dec 2014 Line 6 x 10.27% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.00% (Jan-Jun) or 5.08% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(D) N/A

(E) The POD project spend and revenue requirements associated with 2012 and prior activities are jurisdictionalized using the 2012 Production Base Demand separation factor. The revenue requirements associated with the 2013 period and after are jurisdictionalized using the 2013 Production Base Demand separation factor.

(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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: NPDES - Intermediate (Project 16)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | ($35,679) | $22,117 | $12,770 | $19,778 | $17,268 | ($62,938) | ($28,062) | $0 | $0 | $0 | $0 | $0 | ($54,746) |
| | b. Clearings to Plant | | | | (35,679) | 22,117 | 12,770 | 19,778 | 17,268 | (62,938) | 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 | | | $12,949,257 | 12,913,579 | 12,935,695 | 12,948,466 | 12,968,244 | 12,985,511 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | |
| 3 | Less: Accumulated Depreciation | | | 0 | (35,871) | (71,803) | (107,771) | (143,794) | (179,865) | (215,761) | (251,657) | (287,553) | (323,449) | (359,345) | (395,241) | (431,137) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $12,949,257 | $12,877,708 | $12,863,892 | $12,840,695 | $12,824,450 | $12,805,646 | $12,706,812 | $12,642,854 | $12,606,958 | $12,571,062 | $12,535,166 | $12,499,270 | $12,463,374 | |
| 6 | Average Net Investment | | | | $12,913,482 | $12,870,800 | $12,852,293 | $12,832,572 | $12,815,048 | $12,756,229 | $12,674,833 | $12,624,906 | $12,589,010 | $12,553,114 | $12,517,218 | $12,481,322 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% | 2.03% | | 21,522 | 21,451 | 21,420 | 21,388 | 21,358 | 21,260 | 21,401 | 21,317 | 21,257 | 21,196 | 21,135 | 21,075 | 255,780 |
| | b. Equity Component Grossed Up For Taxes | 8.27% | 8.33% | | 88,998 | 88,704 | 88,576 | 88,440 | 88,320 | 87,914 | 88,036 | 87,689 | 87,440 | 87,191 | 86,941 | 86,692 | 1,054,941 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.3333% | | | 35,871 | 35,932 | 35,968 | 36,023 | 36,071 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 431,137 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/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 | | | 10,643 | 10,661 | 10,672 | 10,688 | 10,702 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 127,916 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $157,034 | $156,748 | $156,636 | $156,539 | $156,451 | $155,720 | $155,983 | $155,552 | $155,243 | $154,933 | $154,622 | $154,313 | 1,869,774 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $157,034 | $156,748 | $156,636 | $156,539 | $156,451 | $155,720 | $155,983 | $155,552 | $155,243 | $154,933 | $154,622 | $154,313 | 1,869,774 |
| 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) | | | | 114,168 | 113,960 | 113,879 | 113,809 | 113,745 | 113,213 | 113,404 | 113,091 | 112,866 | 112,641 | 112,415 | 112,190 | 1,359,382 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $114,168 | $113,960 | $113,879 | $113,809 | $113,745 | $113,213 | $113,404 | $113,091 | $112,866 | $112,641 | $112,415 | $112,190 | $1,359,382 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
Page 24 of 28

**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $30,431 | $9,608 | $32,461 | $199,244 | $82,915 | $102,779 | $301,204 | $1,326,204 | $476,204 | $126,204 | $76,204 | $76,204 | $2,839,659 |
| | b. Clearings to Plant | | | | 497,491 | 6,929 | 16,452 | 46,672 | 909 | 0 | 0 | 2,078,353 | 476,204 | 126,204 | 76,204 | 76,204 | |
| | 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 | | | $263,323 | 760,814 | 767,743 | 784,195 | 830,867 | 831,776 | 831,776 | 831,776 | 2,910,128 | 3,386,332 | 3,512,536 | 3,588,739 | 3,664,943 | |
| 3 | Less: Accumulated Depreciation | | | (11,074) | (11,620) | (13,052) | (14,513) | (15,904) | (17,448) | (18,992) | (20,536) | (22,080) | (28,126) | (34,395) | (40,798) | (47,336) | |
| 4 | CWIP - Non-Interest Bearing | | | 561,960 | 94,901 | 97,579 | 113,589 | 266,161 | 348,167 | 450,946 | 752,149 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | | $814,209 | $844,095 | $852,271 | $883,271 | $1,081,123 | $1,162,495 | $1,263,729 | $1,563,389 | $2,888,048 | $3,358,206 | $3,478,140 | $3,547,941 | $3,617,607 | |
| 6 | Average Net Investment | | | | $829,152 | $848,183 | $867,771 | $982,197 | $1,121,809 | $1,213,112 | $1,413,559 | $2,225,719 | $3,123,127 | $3,418,173 | $3,513,041 | $3,582,774 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% | 2.03% | | 1,382 | 1,414 | 1,446 | 1,637 | 1,870 | 2,022 | 2,387 | 3,758 | 5,273 | 5,772 | 5,932 | 6,050 | 38,943 |
| | b. Equity Component Grossed Up For Taxes | 8.27% | 8.33% | | 5,714 | 5,846 | 5,981 | 6,769 | 7,731 | 8,361 | 9,818 | 15,459 | 21,692 | 23,742 | 24,401 | 24,885 | 160,399 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | Blended | | | 546 | 1,432 | 1,461 | 1,391 | 1,544 | 1,544 | 1,544 | 1,544 | 6,046 | 6,269 | 6,403 | 6,537 | 36,262 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/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 | | | 38 | 109 | 112 | 108 | 118 | 118 | 118 | 118 | 481 | 498 | 509 | 520 | 2,847 |
| | e. Other (E) | | | | 0 | 0 | (597) | (597) | (597) | (597) | (597) | (597) | (597) | (597) | (597) | (597) | (5,967) |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $7,680 | $8,801 | $8,403 | $9,308 | $10,666 | $11,448 | $13,270 | $20,282 | $32,895 | $35,685 | $36,649 | $37,396 | 232,485 |
| | a. Recoverable Costs Allocated to Energy | | | | 7,680 | 8,801 | 8,403 | 9,308 | 10,666 | 11,448 | 13,270 | 20,282 | 32,895 | 35,685 | 36,649 | 37,396 | 232,485 |
| | b. Recoverable Costs Allocated to Demand | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | | 0.96920 | 0.97990 | 0.97660 | 0.96410 | 0.94750 | 0.95600 | 0.97335 | 0.97071 | 0.96978 | 0.97063 | 0.97372 | 0.98187 | |
| 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) | | | | $7,443 | $8,624 | $8,207 | $8,974 | $10,106 | $10,945 | $12,917 | $19,688 | $31,901 | $34,637 | $35,685 | $36,718 | $225,845 |
| 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) | | | | $7,443 | $8,624 | $8,207 | $8,974 | $10,106 | $10,945 | $12,917 | $19,688 | $31,901 | $34,637 | $35,685 | $36,718 | $225,845 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.

(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $204,857 | $211,629 | $1,865 | $60,882 | ($34,562) | $64,739 | $0 | $0 | $0 | $0 | $0 | $0 | $509,410 |
| | b. Clearings to Plant | | | | 204,857 | 211,629 | 1,865 | 60,882 | (34,562) | 64,739 | 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 | | | $134,240,865 | 134,445,722 | 134,657,351 | 134,659,216 | 134,720,098 | 134,685,536 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | |
| 3 | Less: Accumulated Depreciation | | | (2,898,693) | (3,142,062) | (3,385,814) | (3,629,570) | (3,873,436) | (4,117,239) | (4,361,159) | (4,605,079) | (4,848,999) | (5,092,919) | (5,336,839) | (5,580,759) | (5,824,679) | |
| 4 | CWIP - AFUDC Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | | $131,342,171 | $131,303,660 | $131,271,537 | $131,029,646 | $130,846,662 | $130,568,297 | $130,389,116 | $130,145,196 | $129,901,276 | $129,657,356 | $129,413,436 | $129,169,516 | $128,925,596 | |
| 6 | Average Net Investment | | | | $131,322,916 | $131,287,598 | $131,150,591 | $130,938,154 | $130,707,479 | $130,478,706 | $130,267,156 | $130,023,236 | $129,779,316 | $129,535,396 | $129,291,476 | $129,047,556 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% | 2.03% | | 218,872 | 218,813 | 218,584 | 218,230 | 217,846 | 217,465 | 219,956 | 219,544 | 219,132 | 218,721 | 218,309 | 217,897 | 2,623,369 |
| | b. Equity Component Grossed Up For Taxes | 8.27% | 8.33% | | 905,061 | 904,818 | 903,873 | 902,409 | 900,819 | 899,243 | 904,801 | 903,107 | 901,413 | 899,718 | 898,024 | 896,330 | 10,819,616 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.1722% | | | 243,369 | 243,752 | 243,756 | 243,866 | 243,803 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 2,925,986 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/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) | 0.007910 | | | 88,622 | 88,762 | 88,763 | 88,803 | 88,780 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 1,065,491 |
| | 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) | | | | $1,441,130 | $1,441,351 | $1,440,182 | $1,438,514 | $1,436,454 | $1,434,657 | $1,442,706 | $1,440,600 | $1,438,494 | $1,436,388 | $1,434,282 | $1,432,176 | 17,256,928 |
| | a. Recoverable Costs Allocated to Energy | | | | 1,441,130 | 1,441,351 | 1,440,182 | 1,438,514 | 1,436,454 | 1,434,657 | 1,442,706 | 1,440,600 | 1,438,494 | 1,436,388 | 1,434,282 | 1,432,176 | 17,256,928 |
| | b. Recoverable Costs Allocated to Demand | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | | 0.96920 | 0.97990 | 0.97660 | 0.96410 | 0.94750 | 0.95600 | 0.97335 | 0.97071 | 0.96978 | 0.97063 | 0.97372 | 0.98187 | |
| 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) | | | | $1,396,743 | $1,412,379 | $1,406,481 | $1,386,871 | $1,361,040 | $1,371,532 | $1,404,260 | $1,398,410 | $1,395,019 | $1,394,203 | $1,396,581 | $1,406,209 | $16,729,728 |
| 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) | | | | $1,396,743 | $1,412,379 | $1,406,481 | $1,386,871 | $1,361,040 | $1,371,532 | $1,404,260 | $1,398,410 | $1,395,019 | $1,394,203 | $1,396,581 | $1,406,209 | $16,729,728 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.

(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - CRYSTAL RIVER UNITS 1 & 2 - Energy (Project 17.2)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $370,429 | $654,647 | $2,928,591 | $2,543,601 | $2,847,982 | $979,605 | $1,510,648 | $650,648 | $359,648 | $772,648 | $712,648 | $702,648 | $15,033,744 |
| | b. Clearings to Plant | | | | 2,459,343 | 26,871 | 98,322 | (43,556) | 9,512,569 | 740,095 | 440,000 | 254,636 | 0 | 2,207,105 | 0 | 520,000 | |
| | 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 | | | $3,854,841 | 6,314,184 | 6,341,055 | 6,439,376 | 6,395,820 | 15,908,389 | 16,648,484 | 17,088,484 | 17,343,120 | 17,343,120 | 19,550,225 | 19,550,225 | 20,070,225 | |
| 3 | Less: Accumulated Depreciation | | | (16,418) | (28,414) | (47,966) | (67,821) | (87,541) | (107,261) | (158,594) | (211,283) | (263,972) | (317,447) | (370,922) | (431,202) | (491,482) | |
| 4 | CWIP - Non-Interest Bearing | | | 3,741,848 | 1,652,934 | 2,280,710 | 5,110,980 | 7,698,138 | 1,033,550 | 1,273,061 | 2,343,709 | 2,739,721 | 3,099,369 | 1,664,913 | 2,377,561 | 2,560,209 | |
| 5 | Net Investment (Lines 2 + 3 ) | | | $7,580,272 | $7,938,705 | $8,573,799 | $11,482,536 | $14,006,417 | $16,834,678 | $17,762,951 | $19,220,910 | $19,818,869 | $20,125,042 | $20,844,216 | $21,496,584 | $22,138,952 | |
| 6 | Average Net Investment | | | | $7,759,488 | $8,256,252 | $10,028,167 | $12,744,476 | $15,420,548 | $17,298,815 | $18,491,930 | $19,519,890 | $19,971,956 | $20,484,629 | $21,170,400 | $21,817,768 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% | 2.03% | | 12,932 | 13,760 | 16,714 | 21,241 | 25,701 | 28,831 | 31,224 | 32,959 | 33,723 | 34,588 | 35,746 | 36,839 | 324,258 |
| | b. Equity Component Grossed Up For Taxes | 8.27% | 8.33% | | 53,477 | 56,901 | 69,113 | 87,833 | 106,276 | 119,221 | 128,440 | 135,580 | 138,720 | 142,281 | 147,044 | 151,540 | 1,336,426 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.7000% | | | 11,996 | 19,552 | 19,855 | 19,720 | 19,720 | 51,333 | 52,689 | 52,689 | 53,475 | 53,475 | 60,280 | 60,280 | 475,064 |
| | 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) | 0.001703 | | | 552 | 900 | 914 | 908 | 908 | 2,363 | 2,425 | 2,425 | 2,461 | 2,461 | 2,774 | 2,774 | 21,865 |
| | e. Other (E) | | | | (9,111) | (9,111) | (10,540) | (10,540) | (10,540) | (10,540) | (10,540) | (10,540) | (10,540) | (10,540) | (10,540) | (10,540) | (123,619) |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $69,846 | $82,002 | $96,056 | $119,162 | $142,065 | $191,208 | $204,238 | $213,113 | $217,839 | $222,265 | $235,304 | $240,893 | 2,033,994 |
| | a. Recoverable Costs Allocated to Energy | | | | 69,846 | 82,002 | 96,056 | 119,162 | 142,065 | 191,208 | 204,238 | 213,113 | 217,839 | 222,265 | 235,304 | 240,893 | 2,033,994 |
| | b. Recoverable Costs Allocated to Demand | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | | 0.96920 | 0.97990 | 0.97660 | 0.96410 | 0.94750 | 0.95600 | 0.97335 | 0.97071 | 0.96978 | 0.97063 | 0.97372 | 0.98187 | |
| 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) | | | | $67,695 | $80,354 | $93,809 | $114,884 | $134,607 | $182,795 | $198,796 | $206,872 | $211,256 | $215,738 | $229,119 | $236,526 | $1,972,451 |
| 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) | | | | $67,695 | $80,354 | $93,809 | $114,884 | $134,607 | $182,795 | $198,796 | $206,872 | $211,256 | $215,738 | $229,119 | $236,526 | $1,972,451 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.

(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-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 2015 - December 2015**

Docket No. 150007-EI
Duke Energy Florida
Witness: T. G. Foster
Exh. No. __ (TGF-3)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Energy (Project 18)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $100,000 | $500,000 | $500,000 | $500,000 | $0 | $0 | $1,600,000 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 100,000 | 0 | 0 | 1,500,000 | 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 | 100,000 | 100,000 | 100,000 | 1,600,000 | 1,600,000 | 1,600,000 | |
| 3 | Less: Accumulated Depreciation | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (206) | (412) | (618) | (3,911) | (7,204) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 500,000 | 1,000,000 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $100,000 | $599,794 | $1,099,588 | $1,599,382 | $1,596,089 | $1,592,796 | |
| 6 | Average Net Investment | | | | $0 | $0 | $0 | $0 | $0 | $0 | $50,000 | $349,897 | $849,691 | $1,349,485 | $1,597,736 | $1,594,443 | |
| 7 | Return on Average Net Investment (B) | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% | 2.03% | | 0 | 0 | 0 | 0 | 0 | 0 | 84 | 591 | 1,435 | 2,279 | 2,698 | 2,692 | 9,779 |
| | b. Equity Component Grossed Up For Taxes | 8.27% | 8.33% | | 0 | 0 | 0 | 0 | 0 | 0 | 347 | 2,430 | 5,902 | 9,373 | 11,097 | 11,075 | 40,224 |
| | 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 | 206 | 206 | 206 | 3,293 | 3,293 | 7,204 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/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 | 14 | 14 | 14 | 227 | 227 | 496 |
| | 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 | $431 | $3,241 | $7,557 | $11,872 | $17,315 | $17,287 | 57,703 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 431 | 3,241 | 7,557 | 11,872 | 17,315 | 17,287 | 57,703 |
| | b. Recoverable Costs Allocated to Demand | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | | 0.96920 | 0.97990 | 0.97660 | 0.96410 | 0.94750 | 0.95600 | 0.97335 | 0.97071 | 0.96978 | 0.97063 | 0.97372 | 0.98187 | |
| 11 | Demand Jurisdictional Factor | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | | | $0 | $0 | $0 | $0 | $0 | $0 | $420 | $3,146 | $7,329 | $11,523 | $16,860 | $16,974 | $56,252 |
| 13 | Retail Demand-Related Recoverable Costs (F) | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | | $0 | $0 | $0 | $0 | $0 | $0 | $420 | $3,146 | $7,329 | $11,523 | $16,860 | $16,974 | $56,252 |

Notes:

(A) N/A

(B) Jan - Jun 2015 Line 6 x 10.27% x 1/12. Jul - Dec 2015 Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.08% (Jan-Jun) or 5.12% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2015 - December 2015**

**Capital Structure and Cost Rates**

| Class of Capital | Retail Amount | Ratio | Cost Rate | Weighted Cost Rate | PreTax Weighted Cost Rate |
|---|---|---|---|---|---|
| CE | $4,101,842.07 | 48.36% | 0.10500 | 5.080% | 8.270% |
| PS | - | 0.00% | 0.00000 | 0.000% | 0.000% |
| LTD | 3,174,547 | 37.42% | 0.05216 | 1.950% | 1.950% |
| STD | 79,303 | 0.93% | 0.01220 | 0.010% | 0.010% |
| CD-Active | 157,817 | 1.86% | 0.02254 | 0.040% | 0.040% |
| CD-Inactive | 1,181 | 0.01% | 0.00000 | 0.000% | 0.000% |
| ADIT | 1,114,885 | 13.14% | 0.00000 | 0.000% | 0.000% |
| FAS 109 | (148,097) | -1.75% | 0.00000 | 0.000% | 0.000% |
| ITC | 1,246 | 0.01% | 0.00000 | 0.000% | 0.000% |
| Total | $ 8,482,724 | 100.00% | | 7.080% | 10.270% |
| | | | Total Debt | 2.000% | 2.000% |
| | | | Total Equity | 5.080% | 8.270% |

May 2014 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 | $4,681,853.42 | 48.76% | 0.10500 | 5.120% | 8.335% |
| PS | - | 0.00% | 0.00000 | 0.000% | 0.000% |
| LTD | 3,672,596 | 38.25% | 0.05187 | 1.984% | 1.984% |
| STD | (90,568) | -0.94% | 0.00170 | -0.002% | -0.002% |
| CD-Active | 182,163 | 1.90% | 0.02306 | 0.044% | 0.044% |
| CD-Inactive | 1,306 | 0.01% | 0.00000 | 0.000% | 0.000% |
| ADIT | 1,318,615 | 13.73% | 0.00000 | 0.000% | 0.000% |
| FAS 109 | (164,391) | -1.71% | 0.00000 | 0.000% | 0.000% |
| ITC | 498 | 0.01% | 0.00000 | 0.000% | 0.000% |
| Total | $ 9,602,073 | 100.00% | | 7.146% | 10.361% |
| | | | Total Debt | 2.026% | 2.026% |
| | | | Total Equity | 5.120% | 8.335% |

May 2015 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Capital Program Detail**

**January 2015 - December 2015**
**Actuals for the Period January 2015 - June 2015**
**Estimates for the Period July 2015 - December 2015**
**Docket No. 150007-EI**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 13
PARTY: DUKE ENERGY FLORIDA, LLC
(DEF) – (DIRECT)
DESCRIPTION: Thomas G. Foster TGF-4

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | 33,952 | 33,952 | 33,952 | 33,952 | 33,952 | 33,952 | 33,952 | |
| 3 | Less: Accumulated Depreciation | | (8,701) | (8,754) | (8,807) | (8,860) | (8,913) | (8,966) | (9,019) | (9,072) | (9,125) | (9,178) | (9,231) | (9,284) | (9,337) | |
| 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) | | $25,252 | $25,199 | $25,146 | $25,093 | $25,040 | $24,987 | $24,934 | $24,881 | $24,828 | $24,775 | $24,722 | $24,669 | $24,616 | |
| 6 | Average Net Investment | | | 25,225 | 25,172 | 25,119 | 25,066 | 25,013 | 24,960 | 24,907 | 24,854 | 24,801 | 24,748 | 24,695 | 24,642 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% 2.03% | | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 504 |
| | b. Equity Component Grossed Up For Taxes | 8.27% 8.33% | | 174 | 173 | 173 | 173 | 172 | 172 | 173 | 173 | 172 | 172 | 172 | 171 | 2,070 |
| | 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 | 53 | 53 | 53 | 53 | 53 | 53 | 636 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.009672 | | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 324 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $296 | $295 | $295 | $295 | $294 | $294 | $295 | $295 | $294 | $294 | $294 | $293 | $3,534 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $296 | $295 | $295 | $295 | $294 | $294 | $295 | $295 | $294 | $294 | $294 | $293 | $3,534 |

**For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $1,536,272 | 1,536,272 | 1,536,272 | 1,536,272 | 1,536,272 | 1,536,272 | 1,536,272 | 1,536,272 | 1,536,272 | 1,536,272 | 1,536,272 | 1,536,272 | 1,536,272 | |
| 3 | Less: Accumulated Depreciation | | (532,137) | (535,412) | (538,687) | (541,962) | (545,237) | (548,512) | (551,787) | (555,062) | (558,337) | (561,612) | (564,887) | (568,162) | (571,437) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $1,004,135 | $1,000,860 | $997,585 | $994,310 | $991,035 | $987,760 | $984,485 | $981,210 | $977,935 | $974,660 | $971,385 | $968,110 | $964,835 | |
| 6 | Average Net Investment | | | 1,002,498 | 999,223 | 995,948 | 992,673 | 989,398 | 986,123 | 982,848 | 979,573 | 976,298 | 973,023 | 969,748 | 966,473 | |
| 7 | Return on Average Net Investment (A) | Jan-Jun Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | 2.00% 2.03% | | 1,671 | 1,665 | 1,660 | 1,654 | 1,649 | 1,644 | 1,660 | 1,654 | 1,648 | 1,643 | 1,637 | 1,632 | 19,817 |
| | b. Equity Component Grossed Up For Taxes | 8.27% 8.33% | | 6,909 | 6,887 | 6,864 | 6,841 | 6,819 | 6,796 | 6,827 | 6,804 | 6,781 | 6,758 | 6,736 | 6,713 | 81,735 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation | 2.5579% | | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 39,300 |
| | 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 | 0.009672 | | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 14,856 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $13,093 | $13,065 | $13,037 | $13,008 | $12,981 | $12,953 | $13,000 | $12,971 | $12,942 | $12,914 | $12,886 | $12,858 | $155,708 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $13,093 | $13,065 | $13,037 | $13,008 | $12,981 | $12,953 | $13,000 | $12,971 | $12,942 | $12,914 | $12,886 | $12,858 | $155,708 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | |
| 3 | Less: Accumulated Depreciation | | | (155,140) | (157,078) | (159,016) | (160,954) | (162,892) | (164,830) | (166,768) | (168,706) | (170,644) | (172,582) | (174,520) | (176,458) | (178,396) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $754,267 | $752,329 | $750,391 | $748,453 | $746,515 | $744,577 | $742,639 | $740,701 | $738,763 | $736,825 | $734,887 | $732,949 | $731,011 | |
| 6 | Average Net Investment | | | | 753,298 | 751,360 | 749,422 | 747,484 | 745,546 | 743,608 | 741,670 | 739,732 | 737,794 | 735,856 | 733,918 | 731,980 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | 1,255 | 1,252 | 1,249 | 1,246 | 1,243 | 1,239 | 1,252 | 1,249 | 1,246 | 1,242 | 1,239 | 1,236 | 14,948 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | 5,192 | 5,178 | 5,165 | 5,152 | 5,138 | 5,125 | 5,151 | 5,138 | 5,125 | 5,111 | 5,098 | 5,084 | 61,657 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 2.5579% | | | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 23,256 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.009672 | | | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 8,796 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $9,118 | $9,101 | $9,085 | $9,069 | $9,052 | $9,035 | $9,074 | $9,058 | $9,042 | $9,024 | $9,008 | $8,991 | $108,657 |
| | 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 | | | | $9,118 | $9,101 | $9,085 | $9,069 | $9,052 | $9,035 | $9,074 | $9,058 | $9,042 | $9,024 | $9,008 | $8,991 | $108,657 |

**For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | |
| 3 | Less: Accumulated Depreciation | | | (13,800) | (14,178) | (14,556) | (14,934) | (15,312) | (15,690) | (16,068) | (16,446) | (16,824) | (17,202) | (17,580) | (17,958) | (18,336) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $121,274 | $120,896 | $120,518 | $120,140 | $119,762 | $119,384 | $119,006 | $118,628 | $118,250 | $117,872 | $117,494 | $117,116 | $116,738 | |
| 6 | Average Net Investment | | | | 121,085 | 120,707 | 120,329 | 119,951 | 119,573 | 119,195 | 118,817 | 118,439 | 118,061 | 117,683 | 117,305 | 116,927 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | 202 | 201 | 201 | 200 | 199 | 199 | 201 | 200 | 199 | 199 | 198 | 197 | 2,396 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | 835 | 832 | 829 | 827 | 824 | 821 | 825 | 823 | 820 | 817 | 815 | 812 | 9,880 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 3.3596% | | | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 4,536 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.009672 | | | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 1,308 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,524 | $1,520 | $1,517 | $1,514 | $1,510 | $1,507 | $1,513 | $1,510 | $1,506 | $1,503 | $1,500 | $1,496 | $18,120 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,524 | $1,520 | $1,517 | $1,514 | $1,510 | $1,507 | $1,513 | $1,510 | $1,506 | $1,503 | $1,500 | $1,496 | $18,120 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | | $2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | |
| 3 | Less: Accumulated Depreciation | | | | (343,767) | (348,925) | (354,083) | (359,241) | (364,399) | (369,557) | (374,715) | (379,873) | (385,031) | (390,189) | (395,347) | (400,505) | (405,663) | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $1,722,833 | $1,717,675 | $1,712,517 | $1,707,359 | $1,702,201 | $1,697,043 | $1,691,885 | $1,686,727 | $1,681,569 | $1,676,411 | $1,671,253 | $1,666,095 | $1,660,937 | |
| 6 | Average Net Investment | | | | | 1,720,254 | 1,715,096 | 1,709,938 | 1,704,780 | 1,699,622 | 1,694,464 | 1,689,306 | 1,684,148 | 1,678,990 | 1,673,832 | 1,668,674 | 1,663,516 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 2,867 | 2,858 | 2,850 | 2,841 | 2,833 | 2,824 | 2,852 | 2,844 | 2,835 | 2,826 | 2,818 | 2,809 | 34,057 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 11,856 | 11,820 | 11,785 | 11,749 | 11,714 | 11,678 | 11,733 | 11,698 | 11,662 | 11,626 | 11,590 | 11,554 | 140,465 |
| | c. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | | |
| | a. Depreciation | Blended | | | | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 61,896 |
| | b. Amortization | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.011680 | | | | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 24,132 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $21,892 | $21,847 | $21,804 | $21,759 | $21,716 | $21,671 | $21,754 | $21,711 | $21,666 | $21,621 | $21,577 | $21,532 | $260,550 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $21,892 | $21,847 | $21,804 | $21,759 | $21,716 | $21,671 | $21,754 | $21,711 | $21,666 | $21,621 | $21,577 | $21,532 | $260,550 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (248,331) | (252,016) | (255,701) | (259,386) | (263,071) | (266,756) | (270,441) | (274,126) | (277,811) | (281,496) | (285,181) | (288,866) | (292,551) | |
| 4 | CWIP - Non-Interest Bearing | | | | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $1,225,470 | $1,221,785 | $1,218,100 | $1,214,415 | $1,210,730 | $1,207,045 | $1,203,360 | $1,199,675 | $1,195,990 | $1,192,305 | $1,188,620 | $1,184,935 | $1,181,250 | |
| 6 | Average Net Investment | | | | | 1,223,627 | 1,219,942 | 1,216,257 | 1,212,572 | 1,208,887 | 1,205,202 | 1,201,517 | 1,197,832 | 1,194,147 | 1,190,462 | 1,186,777 | 1,183,092 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 2,039 | 2,033 | 2,027 | 2,021 | 2,015 | 2,009 | 2,029 | 2,023 | 2,016 | 2,010 | 2,004 | 1,998 | 24,224 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 8,433 | 8,408 | 8,382 | 8,357 | 8,331 | 8,306 | 8,345 | 8,320 | 8,294 | 8,269 | 8,243 | 8,217 | 99,905 |
| | 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 | 0.009890 | | | | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 14,580 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $15,372 | $15,341 | $15,309 | $15,278 | $15,246 | $15,215 | $15,274 | $15,243 | $15,210 | $15,179 | $15,147 | $15,115 | $182,929 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $15,372 | $15,341 | $15,309 | $15,278 | $15,246 | $15,215 | $15,274 | $15,243 | $15,210 | $15,179 | $15,147 | $15,115 | $182,929 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (724,463) | (733,602) | (742,741) | (751,880) | (761,019) | (770,158) | (779,297) | (788,436) | (797,575) | (806,714) | (815,853) | (824,992) | (834,131) | |
| 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) | | | $937,201 | $928,062 | $918,923 | $909,784 | $900,645 | $891,506 | $882,367 | $873,228 | $864,089 | $854,950 | $845,811 | $836,672 | $827,533 | |
| 6 | Average Net Investment | | | | 932,632 | 923,493 | 914,354 | 905,215 | 896,076 | 886,937 | 877,798 | 868,659 | 859,520 | 850,381 | 841,242 | 832,103 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | 1,554 | 1,539 | 1,524 | 1,509 | 1,493 | 1,478 | 1,482 | 1,467 | 1,451 | 1,436 | 1,420 | 1,405 | 17,758 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | 6,428 | 6,365 | 6,302 | 6,239 | 6,176 | 6,113 | 6,097 | 6,033 | 5,970 | 5,907 | 5,843 | 5,780 | 73,253 |
| | 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 | 0.008700 | | | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 14,460 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $18,326 | $18,248 | $18,170 | $18,092 | $18,013 | $17,935 | $17,923 | $17,844 | $17,765 | $17,687 | $17,607 | $17,529 | $215,139 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $18,326 | $18,248 | $18,170 | $18,092 | $18,013 | $17,935 | $17,923 | $17,844 | $17,765 | $17,687 | $17,607 | $17,529 | $215,139 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (64,121) | (64,837) | (65,553) | (66,269) | (66,985) | (67,701) | (68,417) | (69,133) | (69,849) | (70,565) | (71,281) | (71,997) | (72,713) | |
| 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) | | | $114,817 | $114,101 | $113,385 | $112,669 | $111,953 | $111,237 | $110,521 | $109,805 | $109,089 | $108,373 | $107,657 | $106,941 | $106,225 | |
| 6 | Average Net Investment | | | | 114,459 | 113,743 | 113,027 | 112,311 | 111,595 | 110,879 | 110,163 | 109,447 | 108,731 | 108,015 | 107,299 | 106,583 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | 191 | 190 | 188 | 187 | 186 | 185 | 186 | 185 | 184 | 182 | 181 | 180 | 2,225 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | 789 | 784 | 779 | 774 | 769 | 764 | 765 | 760 | 755 | 750 | 745 | 740 | 9,174 |
| | 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 | 0.009380 | | | 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) | | | | $1,836 | $1,830 | $1,823 | $1,817 | $1,811 | $1,805 | $1,807 | $1,801 | $1,795 | $1,788 | $1,782 | $1,776 | $21,671 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,836 | $1,830 | $1,823 | $1,817 | $1,811 | $1,805 | $1,807 | $1,801 | $1,795 | $1,788 | $1,782 | $1,776 | $21,671 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (155,012) | (156,834) | (158,656) | (160,478) | (162,300) | (164,122) | (165,944) | (167,766) | (169,588) | (171,410) | (173,232) | (175,054) | (176,876) | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $575,283 | $573,461 | $571,639 | $569,817 | $567,995 | $566,173 | $564,351 | $562,529 | $560,707 | $558,885 | $557,063 | $555,241 | $553,419 | |
| 6 | Average Net Investment | | | | | 574,372 | 572,550 | 570,728 | 568,906 | 567,084 | 565,262 | 563,440 | 561,618 | 559,796 | 557,974 | 556,152 | 554,330 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 957 | 954 | 951 | 948 | 945 | 942 | 951 | 948 | 945 | 942 | 939 | 936 | 11,358 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 3,958 | 3,946 | 3,933 | 3,921 | 3,908 | 3,896 | 3,914 | 3,901 | 3,888 | 3,876 | 3,863 | 3,850 | 46,854 |
| | 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 | 0.009890 | | | | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 7,224 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $7,339 | $7,324 | $7,308 | $7,293 | $7,277 | $7,262 | $7,289 | $7,273 | $7,257 | $7,242 | $7,226 | $7,210 | $87,300 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $7,339 | $7,324 | $7,308 | $7,293 | $7,277 | $7,262 | $7,289 | $7,273 | $7,257 | $7,242 | $7,226 | $7,210 | $87,300 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (255,480) | (258,332) | (261,184) | (264,036) | (266,888) | (269,740) | (272,592) | (275,444) | (278,296) | (281,148) | (284,000) | (286,852) | (289,704) | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $781,719 | $778,867 | $776,015 | $773,163 | $770,311 | $767,459 | $764,607 | $761,755 | $758,903 | $756,051 | $753,199 | $750,347 | $747,495 | |
| 6 | Average Net Investment | | | | | 780,293 | 777,441 | 774,589 | 771,737 | 768,885 | 766,033 | 763,181 | 760,329 | 757,477 | 754,625 | 751,773 | 748,921 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 1,300 | 1,296 | 1,291 | 1,286 | 1,281 | 1,277 | 1,289 | 1,284 | 1,279 | 1,274 | 1,269 | 1,265 | 15,391 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 5,378 | 5,358 | 5,338 | 5,319 | 5,299 | 5,279 | 5,301 | 5,281 | 5,261 | 5,241 | 5,222 | 5,202 | 63,479 |
| | 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 | 0.008630 | | | | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 8,952 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $10,276 | $10,252 | $10,227 | $10,203 | $10,178 | $10,154 | $10,188 | $10,163 | $10,138 | $10,113 | $10,089 | $10,065 | $122,046 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $10,276 | $10,252 | $10,227 | $10,203 | $10,178 | $10,154 | $10,188 | $10,163 | $10,138 | $10,113 | $10,089 | $10,065 | $122,046 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (445,934) | (453,771) | (461,608) | (469,445) | (477,282) | (485,119) | (492,956) | (500,793) | (508,630) | (516,467) | (524,304) | (532,141) | (539,978) | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $3,170,970 | $3,163,133 | $3,155,296 | $3,147,459 | $3,139,622 | $3,131,785 | $3,123,948 | $3,116,111 | $3,108,274 | $3,100,437 | $3,092,600 | $3,084,763 | $3,076,926 | |
| 6 | Average Net Investment | | | | | 3,167,051 | 3,159,214 | 3,151,377 | 3,143,540 | 3,135,703 | 3,127,866 | 3,120,029 | 3,112,192 | 3,104,355 | 3,096,518 | 3,088,681 | 3,080,844 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 5,278 | 5,265 | 5,252 | 5,239 | 5,226 | 5,213 | 5,268 | 5,255 | 5,242 | 5,228 | 5,215 | 5,202 | 62,883 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 21,827 | 21,773 | 21,719 | 21,665 | 21,611 | 21,557 | 21,671 | 21,616 | 21,562 | 21,508 | 21,453 | 21,399 | 259,361 |
| | 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 | 0.011680 | | | | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 42,240 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $38,462 | $38,395 | $38,328 | $38,261 | $38,194 | $38,127 | $38,296 | $38,228 | $38,161 | $38,093 | $38,025 | $37,958 | $458,528 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $38,462 | $38,395 | $38,328 | $38,261 | $38,194 | $38,127 | $38,296 | $38,228 | $38,161 | $38,093 | $38,025 | $37,958 | $458,528 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (51,666) | (51,907) | (52,148) | (52,389) | (52,630) | (52,871) | (53,112) | (53,353) | (53,594) | (53,835) | (54,076) | (54,317) | (54,558) | |
| 4 | CWIP - Non-Interest Bearing | | | | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $89,768 | $89,527 | $89,286 | $89,045 | $88,804 | $88,563 | $88,322 | $88,081 | $87,840 | $87,599 | $87,358 | $87,117 | $86,876 | |
| 6 | Average Net Investment | | | | | 89,648 | 89,407 | 89,166 | 88,925 | 88,684 | 88,443 | 88,202 | 87,961 | 87,720 | 87,479 | 87,238 | 86,997 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 149 | 149 | 149 | 148 | 148 | 147 | 149 | 149 | 148 | 148 | 147 | 147 | 1,778 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 618 | 616 | 615 | 613 | 611 | 610 | 613 | 611 | 609 | 608 | 606 | 604 | 7,334 |
| | 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 | 0.012880 | | | | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 1,824 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $1,160 | $1,158 | $1,157 | $1,154 | $1,152 | $1,150 | $1,155 | $1,153 | $1,150 | $1,149 | $1,146 | $1,144 | $13,828 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $1,160 | $1,158 | $1,157 | $1,154 | $1,152 | $1,150 | $1,155 | $1,153 | $1,150 | $1,149 | $1,146 | $1,144 | $13,828 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (118,416) | (120,193) | (121,970) | (123,747) | (125,524) | (127,301) | (129,078) | (130,855) | (132,632) | (134,409) | (136,186) | (137,963) | (139,740) | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $276,552 | $274,775 | $272,998 | $271,221 | $269,444 | $267,667 | $265,890 | $264,113 | $262,336 | $260,559 | $258,782 | $257,005 | $255,228 | |
| 6 | Average Net Investment | | | | | 275,663 | 273,886 | 272,109 | 270,332 | 268,555 | 266,778 | 265,001 | 263,224 | 261,447 | 259,670 | 257,893 | 256,116 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 459 | 456 | 454 | 451 | 448 | 445 | 447 | 444 | 441 | 438 | 435 | 432 | 5,350 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 1,900 | 1,888 | 1,875 | 1,863 | 1,851 | 1,839 | 1,841 | 1,828 | 1,816 | 1,804 | 1,791 | 1,779 | 22,075 |
| | 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 | 0.009890 | | | | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 3,912 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $4,462 | $4,447 | $4,432 | $4,417 | $4,402 | $4,387 | $4,391 | $4,375 | $4,360 | $4,345 | $4,329 | $4,314 | $52,661 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $4,462 | $4,447 | $4,432 | $4,417 | $4,402 | $4,387 | $4,391 | $4,375 | $4,360 | $4,345 | $4,329 | $4,314 | $52,661 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (14,667) | (14,769) | (14,871) | (14,973) | (15,075) | (15,177) | (15,279) | (15,381) | (15,483) | (15,585) | (15,687) | (15,789) | (15,891) | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $18,425 | $18,323 | $18,221 | $18,119 | $18,017 | $17,915 | $17,813 | $17,711 | $17,609 | $17,507 | $17,405 | $17,303 | $17,201 | |
| 6 | Average Net Investment | | | | | 18,374 | 18,272 | 18,170 | 18,068 | 17,966 | 17,864 | 17,762 | 17,660 | 17,558 | 17,456 | 17,354 | 17,252 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 31 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 29 | 29 | 29 | 358 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 127 | 126 | 125 | 125 | 124 | 123 | 123 | 123 | 122 | 121 | 121 | 120 | 1,480 |
| | 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 | 0.001703 | | | | 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) | | | | | $265 | $263 | $262 | $262 | $261 | $260 | $260 | $260 | $259 | $257 | $257 | $256 | $3,122 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $265 | $263 | $262 | $262 | $261 | $260 | $260 | $260 | $259 | $257 | $257 | $256 | $3,122 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Envrionmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | $151,052 | 148,122 | 145,192 | 142,262 | 139,332 | 136,402 | 133,472 | 130,542 | 127,612 | 124,682 | 121,752 | 118,822 | 115,892 | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $2,517,000 | $2,514,070 | $2,511,140 | $2,508,210 | $2,505,280 | $2,502,350 | $2,499,420 | $2,496,490 | $2,493,560 | $2,490,630 | $2,487,700 | $2,484,770 | $2,481,840 | |
| 6 | Average Net Investment | | | | | 2,515,535 | 2,512,605 | 2,509,675 | 2,506,745 | 2,503,815 | 2,500,885 | 2,497,955 | 2,495,025 | 2,492,095 | 2,489,165 | 2,486,235 | 2,483,305 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 4,193 | 4,188 | 4,183 | 4,178 | 4,173 | 4,168 | 4,218 | 4,213 | 4,208 | 4,203 | 4,198 | 4,193 | 50,316 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 17,337 | 17,317 | 17,296 | 17,276 | 17,256 | 17,236 | 17,350 | 17,330 | 17,309 | 17,289 | 17,269 | 17,248 | 207,513 |
| | 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 | 0.001703 | | | | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 4,032 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $24,796 | $24,771 | $24,745 | $24,720 | $24,695 | $24,670 | $24,834 | $24,809 | $24,783 | $24,758 | $24,733 | $24,707 | $297,021 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $24,796 | $24,771 | $24,745 | $24,720 | $24,695 | $24,670 | $24,834 | $24,809 | $24,783 | $24,758 | $24,733 | $24,707 | $297,021 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (53,886) | (54,411) | (54,936) | (55,461) | (55,986) | (56,511) | (57,036) | (57,561) | (58,086) | (58,611) | (59,136) | (59,661) | (60,186) | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $236,412 | $235,887 | $235,362 | $234,837 | $234,312 | $233,787 | $233,262 | $232,737 | $232,212 | $231,687 | $231,162 | $230,637 | $230,112 | |
| 6 | Average Net Investment | | | | | 236,149 | 235,624 | 235,099 | 234,574 | 234,049 | 233,524 | 232,999 | 232,474 | 231,949 | 231,424 | 230,899 | 230,374 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 394 | 393 | 392 | 391 | 390 | 389 | 393 | 393 | 392 | 391 | 390 | 389 | 4,697 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 1,628 | 1,624 | 1,620 | 1,617 | 1,613 | 1,609 | 1,618 | 1,615 | 1,611 | 1,607 | 1,604 | 1,600 | 19,366 |
| | 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 | 0.007910 | | | | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 2,292 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $2,738 | $2,733 | $2,728 | $2,724 | $2,719 | $2,714 | $2,727 | $2,724 | $2,719 | $2,714 | $2,710 | $2,705 | $32,655 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $2,738 | $2,733 | $2,728 | $2,724 | $2,719 | $2,714 | $2,727 | $2,724 | $2,719 | $2,714 | $2,710 | $2,705 | $32,655 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (28,793) | (29,197) | (29,601) | (30,005) | (30,409) | (30,813) | (31,217) | (31,621) | (32,025) | (32,429) | (32,833) | (33,237) | (33,641) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $132,961 | $132,557 | $132,153 | $131,749 | $131,345 | $130,941 | $130,537 | $130,133 | $129,729 | $129,325 | $128,921 | $128,517 | $128,113 | |
| 6 | Average Net Investment | | | | 132,759 | 132,355 | 131,951 | 131,547 | 131,143 | 130,739 | 130,335 | 129,931 | 129,527 | 129,123 | 128,719 | 128,315 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | 221 | 221 | 220 | 219 | 219 | 218 | 220 | 219 | 219 | 218 | 217 | 217 | 2,628 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | 915 | 912 | 909 | 907 | 904 | 901 | 905 | 902 | 900 | 897 | 894 | 891 | 10,837 |
| | 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 | 0.009380 | | | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 1,512 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,666 | $1,663 | $1,659 | $1,656 | $1,653 | $1,649 | $1,655 | $1,651 | $1,649 | $1,645 | $1,641 | $1,638 | $19,825 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,666 | $1,663 | $1,659 | $1,656 | $1,653 | $1,649 | $1,655 | $1,651 | $1,649 | $1,645 | $1,641 | $1,638 | $19,825 |

**For Project: CAIR CTs - BARTOW (Project 7.2b)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (40,969) | (41,327) | (41,685) | (42,043) | (42,401) | (42,759) | (43,117) | (43,475) | (43,833) | (44,191) | (44,549) | (44,907) | (45,265) | |
| 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) | | | $234,378 | $234,020 | $233,662 | $233,304 | $232,946 | $232,588 | $232,230 | $231,872 | $231,514 | $231,156 | $230,798 | $230,440 | $230,082 | |
| 6 | Average Net Investment | | | | 234,199 | 233,841 | 233,483 | 233,125 | 232,767 | 232,409 | 232,051 | 231,693 | 231,335 | 230,977 | 230,619 | 230,261 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | 390 | 390 | 389 | 389 | 388 | 387 | 392 | 391 | 391 | 390 | 389 | 389 | 4,675 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | 1,614 | 1,612 | 1,609 | 1,607 | 1,604 | 1,602 | 1,612 | 1,609 | 1,607 | 1,604 | 1,602 | 1,599 | 19,281 |
| | 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 | 0.009890 | | | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 2,724 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $2,589 | $2,587 | $2,583 | $2,581 | $2,577 | $2,574 | $2,589 | $2,585 | $2,583 | $2,579 | $2,576 | $2,573 | $30,976 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $2,589 | $2,587 | $2,583 | $2,581 | $2,577 | $2,574 | $2,589 | $2,585 | $2,583 | $2,579 | $2,576 | $2,573 | $30,976 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**CAIR CTs (Project 7.2 Recap)**



**For Project: CAIR CTs - BAYBORO (Project 7.2c)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (34,047) | (34,431) | (34,815) | (35,199) | (35,583) | (35,967) | (36,351) | (36,735) | (37,119) | (37,503) | (37,887) | (38,271) | (38,655) | |
| 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) | | | | $164,941 | $164,557 | $164,173 | $163,789 | $163,405 | $163,021 | $162,637 | $162,253 | $161,869 | $161,485 | $161,101 | $160,717 | $160,333 | |
| 6 | Average Net Investment | | | | | 164,749 | 164,365 | 163,981 | 163,597 | 163,213 | 162,829 | 162,445 | 162,061 | 161,677 | 161,293 | 160,909 | 160,525 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 275 | 274 | 273 | 273 | 272 | 271 | 274 | 274 | 273 | 272 | 272 | 271 | 3,274 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 1,135 | 1,133 | 1,130 | 1,127 | 1,125 | 1,122 | 1,128 | 1,126 | 1,123 | 1,120 | 1,118 | 1,115 | 13,502 |
| | 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 | 0.009890 | | | | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 1,968 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $1,958 | $1,955 | $1,951 | $1,948 | $1,945 | $1,941 | $1,950 | $1,948 | $1,944 | $1,940 | $1,938 | $1,934 | $23,352 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $1,958 | $1,955 | $1,951 | $1,948 | $1,945 | $1,941 | $1,950 | $1,948 | $1,944 | $1,940 | $1,938 | $1,934 | $23,352 |

**For Project: CAIR CTs - DeBARY (Project 7.2d)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (19,515) | (19,734) | (19,953) | (20,172) | (20,391) | (20,610) | (20,829) | (21,048) | (21,267) | (21,486) | (21,705) | (21,924) | (22,143) | |
| 4 | CWIP - Non-Interest Bearing | | | | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $68,152 | $67,933 | $67,714 | $67,495 | $67,276 | $67,057 | $66,838 | $66,619 | $66,400 | $66,181 | $65,962 | $65,743 | $65,524 | |
| 6 | Average Net Investment | | | | | 68,042 | 67,823 | 67,604 | 67,385 | 67,166 | 66,947 | 66,728 | 66,509 | 66,290 | 66,071 | 65,852 | 65,633 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 113 | 113 | 113 | 112 | 112 | 112 | 113 | 112 | 112 | 112 | 111 | 111 | 1,346 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 469 | 467 | 466 | 464 | 463 | 461 | 463 | 462 | 460 | 459 | 457 | 456 | 5,547 |
| | 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 | 0.011680 | | | | 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) | | | | | $886 | $884 | $883 | $880 | $879 | $877 | $880 | $878 | $876 | $875 | $872 | $871 | $10,541 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $886 | $884 | $883 | $880 | $879 | $877 | $880 | $878 | $876 | $875 | $872 | $871 | $10,541 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**CAIR CTs (Project 7.2 Recap)**



**For Project: CAIR CTs - HIGGINS (Project 7.2e)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (56,973) | (57,812) | (58,651) | (59,490) | (60,329) | (61,168) | (62,007) | (62,846) | (63,685) | (64,524) | (65,363) | (66,202) | (67,041) | |
| 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) | | | | $290,225 | $289,386 | $288,547 | $287,708 | $286,869 | $286,030 | $285,191 | $284,352 | $283,513 | $282,674 | $281,835 | $280,996 | $280,157 | |
| 6 | Average Net Investment | | | | | 289,805 | 288,966 | 288,127 | 287,288 | 286,449 | 285,610 | 284,771 | 283,932 | 283,093 | 282,254 | 281,415 | 280,576 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 483 | 482 | 480 | 479 | 477 | 476 | 481 | 479 | 478 | 477 | 475 | 474 | 5,741 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 1,997 | 1,992 | 1,986 | 1,980 | 1,974 | 1,968 | 1,978 | 1,972 | 1,966 | 1,960 | 1,955 | 1,949 | 23,677 |
| | 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 | 0.009890 | | | | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 3,432 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $3,605 | $3,599 | $3,591 | $3,584 | $3,576 | $3,569 | $3,584 | $3,576 | $3,569 | $3,562 | $3,555 | $3,548 | $42,918 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $3,605 | $3,599 | $3,591 | $3,584 | $3,576 | $3,569 | $3,584 | $3,576 | $3,569 | $3,562 | $3,555 | $3,548 | $42,918 |

**For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (66,679) | (67,466) | (68,253) | (69,040) | (69,827) | (70,614) | (71,401) | (72,188) | (72,975) | (73,762) | (74,549) | (75,336) | (76,123) | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $282,905 | $282,118 | $281,331 | $280,544 | $279,757 | $278,970 | $278,183 | $277,396 | $276,609 | $275,822 | $275,035 | $274,248 | $273,461 | |
| 6 | Average Net Investment | | | | | 282,511 | 281,724 | 280,937 | 280,150 | 279,363 | 278,576 | 277,789 | 277,002 | 276,215 | 275,428 | 274,641 | 273,854 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 471 | 470 | 468 | 467 | 466 | 464 | 469 | 468 | 466 | 465 | 464 | 462 | 5,600 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 1,947 | 1,942 | 1,936 | 1,931 | 1,925 | 1,920 | 1,929 | 1,924 | 1,919 | 1,913 | 1,908 | 1,902 | 23,096 |
| | 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 | 0.008700 | | | | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 3,036 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $3,458 | $3,452 | $3,444 | $3,438 | $3,431 | $3,424 | $3,438 | $3,432 | $3,425 | $3,418 | $3,412 | $3,404 | $41,176 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $3,458 | $3,452 | $3,444 | $3,438 | $3,431 | $3,424 | $3,438 | $3,432 | $3,425 | $3,418 | $3,412 | $3,404 | $41,176 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**CAIR CTs (Project 7.2 Recap)**



**For Project: CAIR CTs - TURNER (Project 7.2g)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | | $134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | |
| 3 | Less: Accumulated Depreciation | | | | (15,879) | (16,015) | (16,151) | (16,287) | (16,423) | (16,559) | (16,695) | (16,831) | (16,967) | (17,103) | (17,239) | (17,375) | (17,511) | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $118,133 | $117,997 | $117,861 | $117,725 | $117,589 | $117,453 | $117,317 | $117,181 | $117,045 | $116,909 | $116,773 | $116,637 | $116,501 | |
| 6 | Average Net Investment | | | | | 118,065 | 117,929 | 117,793 | 117,657 | 117,521 | 117,385 | 117,249 | 117,113 | 116,977 | 116,841 | 116,705 | 116,569 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 197 | 197 | 196 | 196 | 196 | 196 | 198 | 198 | 198 | 197 | 197 | 197 | 2,363 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 814 | 813 | 812 | 811 | 810 | 809 | 814 | 813 | 812 | 812 | 811 | 810 | 9,741 |
| | c. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | | |
| | a. Depreciation | 1.2187% | | | | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 1,632 |
| | b. Amortization | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.011680 | | | | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 1,560 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $1,277 | $1,276 | $1,274 | $1,273 | $1,272 | $1,271 | $1,278 | $1,277 | $1,276 | $1,275 | $1,274 | $1,273 | $15,296 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $1,277 | $1,276 | $1,274 | $1,273 | $1,272 | $1,271 | $1,278 | $1,277 | $1,276 | $1,275 | $1,274 | $1,273 | $15,296 |

**For Project: CAIR CTs - SUWANNEE (Project 7.2h)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (40,962) | (41,385) | (41,808) | (42,231) | (42,654) | (43,077) | (43,500) | (43,923) | (44,346) | (44,769) | (45,192) | (45,615) | (46,038) | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $340,598 | $340,175 | $339,752 | $339,329 | $338,906 | $338,483 | $338,060 | $337,637 | $337,214 | $336,791 | $336,368 | $335,945 | $335,522 | |
| 6 | Average Net Investment | | | | | 340,386 | 339,963 | 339,540 | 339,117 | 338,694 | 338,271 | 337,848 | 337,425 | 337,002 | 336,579 | 336,156 | 335,733 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 567 | 567 | 566 | 565 | 564 | 564 | 570 | 570 | 569 | 568 | 568 | 567 | 6,805 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 2,346 | 2,343 | 2,340 | 2,337 | 2,334 | 2,331 | 2,347 | 2,344 | 2,341 | 2,338 | 2,335 | 2,332 | 28,068 |
| | 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 | 0.008630 | | | | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 3,288 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $3,610 | $3,607 | $3,603 | $3,599 | $3,595 | $3,592 | $3,614 | $3,611 | $3,607 | $3,603 | $3,600 | $3,596 | $43,237 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $3,610 | $3,607 | $3,603 | $3,599 | $3,595 | $3,592 | $3,614 | $3,611 | $3,607 | $3,603 | $3,600 | $3,596 | $43,237 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $6,058 | $12,003 | $21,452 | $43,572 | $26,097 | $11,157 | $20,000 | $8,843 | $0 | $0 | $0 | $0 | $149,183 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 2,144,255 | 8,843 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | | $16,857 | 16,857 | 16,857 | 16,857 | 16,857 | 16,857 | 16,857 | 2,161,112 | 2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | |
| 3 | Less: Accumulated Depreciation | | | | (500) | (535) | (570) | (605) | (640) | (675) | (710) | (745) | (5,211) | (9,677) | (14,143) | (18,609) | (23,075) | |
| 4 | CWIP - Non-Interest Bearing | | | | 2,003,915 | 2,009,973 | 2,021,976 | 2,043,427 | 2,087,000 | 2,113,097 | 2,124,255 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $2,020,273 | $2,026,295 | $2,038,263 | $2,059,680 | $2,103,218 | $2,129,280 | $2,140,402 | $2,160,367 | $2,164,744 | $2,160,278 | $2,155,812 | $2,151,346 | $2,146,880 | |
| 6 | Average Net Investment | | | | | 2,023,284 | 2,032,279 | 2,048,972 | 2,081,449 | 2,116,249 | 2,134,841 | 2,150,385 | 2,162,556 | 2,162,511 | 2,158,045 | 2,153,579 | 2,149,113 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 3,372 | 3,387 | 3,415 | 3,469 | 3,527 | 3,558 | 3,631 | 3,651 | 3,651 | 3,644 | 3,636 | 3,629 | 42,570 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 13,944 | 14,006 | 14,121 | 14,345 | 14,585 | 14,713 | 14,936 | 15,021 | 15,020 | 14,989 | 14,958 | 14,927 | 175,565 |
| | c. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | | |
| | a. Depreciation | 2.4700% | | | | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 4,466 | 4,466 | 4,466 | 4,466 | 4,466 | 22,575 |
| | b. Amortization | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | | N/A | N/A | N/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 | | | | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 308 | 308 | 308 | 308 | 308 | 1,554 |
| | e. Other | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | | $17,353 | $17,430 | $17,573 | $17,851 | $18,149 | $18,308 | $18,604 | $23,446 | $23,445 | $23,407 | $23,368 | $23,330 | $242,264 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $17,353 | $17,430 | $17,573 | $17,851 | $18,149 | $18,308 | $18,604 | $23,446 | $23,445 | $23,407 | $23,368 | $23,330 | $242,264 |

**For Project: Crystal River 4 and 5 - Conditions of Certification (Project 7.4q)**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (9,509) | (10,269) | (11,029) | (11,789) | (12,549) | (13,309) | (14,069) | (14,829) | (15,589) | (16,349) | (17,109) | (17,869) | (18,629) | |
| 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) | | | | $604,501 | $603,741 | $602,981 | $602,221 | $601,461 | $600,701 | $599,941 | $599,181 | $598,421 | $597,661 | $596,901 | $596,141 | $595,381 | |
| 6 | Average Net Investment | | | | | 604,121 | 603,361 | 602,601 | 601,841 | 601,081 | 600,321 | 599,561 | 598,801 | 598,041 | 597,281 | 596,521 | 595,761 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 1,007 | 1,006 | 1,004 | 1,003 | 1,002 | 1,001 | 1,012 | 1,011 | 1,010 | 1,009 | 1,007 | 1,006 | 12,078 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 4,164 | 4,158 | 4,153 | 4,148 | 4,143 | 4,137 | 4,164 | 4,159 | 4,154 | 4,149 | 4,143 | 4,138 | 49,810 |
| | 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) | | | | | $6,018 | $6,011 | $6,004 | $5,998 | $5,992 | $5,985 | $6,023 | $6,017 | $6,011 | $6,005 | $5,997 | $5,991 | $72,052 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $6,018 | $6,011 | $6,004 | $5,998 | $5,992 | $5,985 | $6,023 | $6,017 | $6,011 | $6,005 | $5,997 | $5,991 | $72,052 |

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-13-0598-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-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**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-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (27,623) | (28,984) | (30,345) | (31,706) | (33,067) | (34,428) | (35,789) | (37,150) | (38,511) | (39,872) | (41,233) | (42,594) | (43,955) | |
| 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) | | | | $633,375 | $632,014 | $630,653 | $629,292 | $627,931 | $626,570 | $625,209 | $623,848 | $622,487 | $621,126 | $619,765 | $618,404 | $617,043 | |
| 6 | Average Net Investment | | | | | 632,695 | 631,334 | 629,973 | 628,612 | 627,251 | 625,890 | 624,529 | 623,168 | 621,807 | 620,446 | 619,085 | 617,724 | |
| 7 | Return on Average Net Investment (A) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 1,054 | 1,052 | 1,050 | 1,048 | 1,045 | 1,043 | 1,055 | 1,052 | 1,050 | 1,048 | 1,045 | 1,043 | 12,585 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 4,360 | 4,351 | 4,342 | 4,332 | 4,323 | 4,314 | 4,338 | 4,328 | 4,319 | 4,309 | 4,300 | 4,291 | 51,907 |
| | 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) | | | | | $6,869 | $6,858 | $6,847 | $6,835 | $6,823 | $6,812 | $6,848 | $6,835 | $6,824 | $6,812 | $6,800 | $6,789 | $81,952 |
| | 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 | | | | | $6,869 | $6,858 | $6,847 | $6,835 | $6,823 | $6,812 | $6,848 | $6,835 | $6,824 | $6,812 | $6,800 | $6,789 | $81,952 |

**For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4s) - CR5 Clinker Mitigation**
**(in Dollars)**

| Line | Description | | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | | (8,318) | (9,359) | (10,400) | (11,441) | (12,482) | (13,523) | (14,564) | (15,605) | (16,646) | (17,687) | (18,728) | (19,769) | (20,810) | |
| 4 | CWIP - Non-Interest Bearing | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | | $497,586 | $496,545 | $495,504 | $494,463 | $493,422 | $492,381 | $491,340 | $490,299 | $489,258 | $488,217 | $487,176 | $486,135 | $485,094 | |
| 6 | Return on Average Net Investment (A) | | | | | 497,066 | 496,025 | 494,984 | 493,943 | 492,902 | 491,861 | 490,820 | 489,779 | 488,738 | 487,697 | 486,656 | 485,615 | |
| 7 | Return on Average Net Investment | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | | 828 | 827 | 825 | 823 | 822 | 820 | 829 | 827 | 825 | 823 | 822 | 820 | 9,891 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | | 3,426 | 3,419 | 3,411 | 3,404 | 3,397 | 3,390 | 3,409 | 3,402 | 3,395 | 3,387 | 3,380 | 3,373 | 40,793 |
| | 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) | | | | | $5,367 | $5,359 | $5,349 | $5,340 | $5,332 | $5,323 | $5,351 | $5,342 | $5,333 | $5,323 | $5,315 | $5,306 | $64,040 |
| | a. Recoverable Costs Allocated to Energy | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | | $5,367 | $5,359 | $5,349 | $5,340 | $5,332 | $5,323 | $5,351 | $5,342 | $5,333 | $5,323 | $5,315 | $5,306 | $64,040 |

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-13-0598-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-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**Thermal Discharge Permanent Cooling Tower (Project 11.1 Recap) - Activity Prior to 1/1/13**



**For Project: Crystal River Thermal Discharge Compliance Project AFUDC - Point of Discharge (POD) Cooling Tower (Project 11.1a)**
**(in Dollars)**
**(Activity Prior to 1/1/13)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 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 | (36,519) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Regulatory Asset Balance | | | $5,610,669 | 5,610,669 | 5,143,113 | 4,639,038 | 4,175,134 | 3,711,231 | 3,247,327 | 2,783,423 | 2,319,519 | 1,855,615 | 1,391,711 | 927,808 | 463,904 | |
| 3 | Less: Amortization (C) | | | 0 | (467,556) | (467,556) | (463,904) | (463,904) | (463,904) | (463,904) | (463,904) | (463,904) | (463,904) | (463,904) | (463,904) | (463,904) | |
| 4 | CWIP - AFUDC Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3) | | | $5,610,669 | $5,143,113 | $4,675,557 | $4,175,134 | $3,711,231 | $3,247,327 | $2,783,423 | $2,319,519 | $1,855,615 | $1,391,711 | $927,808 | $463,904 | $0 | |
| 6 | Average Net Investment | | | | 5,376,891 | 4,909,335 | 4,425,346 | 3,943,182 | 3,479,279 | 3,015,375 | 2,551,471 | 2,087,567 | 1,623,663 | 1,159,760 | 695,856 | 231,952 | |
| 7 | Return on Average Net Investment (B) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | 8,961 | 8,182 | 7,376 | 6,572 | 5,799 | 5,026 | 4,308 | 3,525 | 2,742 | 1,958 | 1,175 | 392 | 56,016 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | 37,057 | 33,835 | 30,499 | 27,176 | 23,979 | 20,782 | 17,722 | 14,500 | 11,278 | 8,055 | 4,833 | 1,611 | 231,327 |
| | c. Other | | | | 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 (C) | 33.3333% | | | 467,556 | 467,556 | 463,904 | 463,904 | 463,904 | 463,904 | 463,904 | 463,904 | 463,904 | 463,904 | 463,904 | 463,904 | 5,574,150 |
| | c. Dismantlement | | | | N/A | N/A | N/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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $513,574 | $509,573 | $501,779 | $497,652 | $493,682 | $489,712 | $485,934 | $481,929 | $477,924 | $473,917 | $469,912 | $465,907 | 5,861,493 |
| | 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 | | | | $513,574 | $509,573 | $501,779 | $497,652 | $493,682 | $489,712 | $485,934 | $481,929 | $477,924 | $473,917 | $469,912 | $465,907 | 5,861,493 |

**For Project: Crystal River Thermal Discharge Compliance Project AFUDC - MET Tower (Project 11.1b)**
**(in Dollars)**
**(Activity Prior to 1/1/13)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Regulatory Asset Balance | | | $113,659 | 113,659 | 104,188 | 94,716 | 85,244 | 75,773 | 66,301 | 56,830 | 47,358 | 37,886 | 28,415 | 18,943 | 9,472 | |
| 3 | Less: Amortization (C) | | | 0 | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | (9,472) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $113,659 | $104,188 | $94,716 | $85,244 | $75,773 | $66,301 | $56,830 | $47,358 | $37,886 | $28,415 | $18,943 | $9,472 | ($0) | |
| 6 | Average Net Investment | | | | 108,923 | 99,452 | 89,980 | 80,509 | 71,037 | 61,565 | 52,094 | 42,622 | 33,151 | 23,679 | 14,207 | 4,736 | |
| 7 | Return on Average Net Investment (B) | | Jan-Jun | Jul-Dec | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% | 2.03% | 182 | 166 | 150 | 134 | 118 | 103 | 88 | 72 | 56 | 40 | 24 | 8 | 1,141 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% | 8.33% | 751 | 685 | 620 | 555 | 490 | 424 | 362 | 296 | 230 | 164 | 99 | 33 | 4,709 |
| | c. Other | | | | 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 (C) | 33.3333% | | | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 9,472 | 113,659 |
| | c. Dismantlement | | | | N/A | N/A | N/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 | | | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 625 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $10,457 | $10,375 | $10,294 | $10,213 | $10,132 | $10,051 | $9,974 | $9,892 | $9,810 | $9,728 | $9,647 | $9,565 | 120,134 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $10,457 | $10,375 | $10,294 | $10,213 | $10,132 | $10,051 | $9,974 | $9,892 | $9,810 | $9,728 | $9,647 | $9,565 | 120,134 |

(A) N/A
(B) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.
(C) Investment amortized over three years in accordance with Order No. PSC-13-0381-PAA-EI.
(D) Property tax calculated on original asset basis of $361,735.

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause (ECRC)**
**Capital Programs Detail Support - January 2015 through December 2015**
**Thermal Discharge Permanent Cooling Tower (Project 11.1 Recap) - Activity After 12/31/12**



**For Project: Crystal River Thermal Discharge Compliance Project AFUDC - Point of Discharge (POD) Cooling Tower (Project 11.1a)**
**(in Dollars)**
**(Activity After 12/31/12)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Regulatory Asset Balance | | | $38,025 | 38,025 | 34,856 | 31,688 | 28,519 | 25,350 | 22,181 | 19,013 | 15,844 | 12,675 | 9,506 | 6,338 | 3,169 | |
| 3 | Less: Amortization (A) | | | 0 | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | (3,169) | |
| 4 | CWIP - AFUDC Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3) | | | $38,025 | $34,856 | $31,688 | $28,519 | $25,350 | $22,181 | $19,013 | $15,844 | $12,675 | $9,506 | $6,338 | $3,169 | ($0) | |
| 6 | Average Net Investment | | | | 36,441 | 33,272 | 30,103 | 26,934 | 23,766 | 20,597 | 17,428 | 14,259 | 11,091 | 7,922 | 4,753 | 1,584 | |
| 7 | Return on Average Net Investment (B) | | Jan-Jun Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% 2.03% | | 61 | 55 | 50 | 45 | 40 | 34 | 29 | 24 | 19 | 13 | 8 | 3 | 381 |
| | b. Equity Component Grossed Up For Taxes | | 8.27% 8.33% | | 251 | 229 | 207 | 186 | 164 | 142 | 121 | 99 | 77 | 55 | 33 | 11 | 1,575 |
| | c. Other | | | | | 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 (A) | 33.3333% | | | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 3,169 | 38,025 |
| | c. Dismantlement | | | | N/A | N/A | N/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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $3,481 | $3,453 | $3,426 | $3,400 | $3,373 | $3,345 | $3,319 | $3,292 | $3,265 | $3,237 | $3,210 | $3,183 | 39,981 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $3,481 | $3,453 | $3,426 | $3,400 | $3,373 | $3,345 | $3,319 | $3,292 | $3,265 | $3,237 | $3,210 | $3,183 | 39,981 |

**For Project: Crystal River Thermal Discharge Compliance Project AFUDC - MET Tower (Project 11.1b)**
**(in Dollars)**
**(Activity After 12/31/12)**

| Line | Description | | | Beginning of Period Amount | Actual Jan-15 | Actual Feb-15 | Actual Mar-15 | Actual Apr-15 | Actual May-15 | Actual Jun-15 | Estimated Jul-15 | Estimated Aug-15 | Estimated Sep-15 | Estimated Oct-15 | Estimated Nov-15 | Estimated Dec-15 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Regulatory Asset Balance | | | ($1,706) | (1,706) | (1,564) | (1,422) | (1,280) | (1,137) | (995) | (853) | (711) | (569) | (427) | (284) | (142) | |
| 3 | Less: Amortization (A) | | | 0 | 142 | 142 | 142 | 142 | 142 | 142 | 142 | 142 | 142 | 142 | 142 | 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) | | | ($1,706) | ($1,564) | ($1,422) | ($1,280) | ($1,137) | ($995) | ($853) | ($711) | ($569) | ($427) | ($284) | ($142) | ($0) | |
| 6 | Average Net Investment | | | | (1,635) | (1,493) | (1,351) | (1,209) | (1,066) | (924) | (782) | (640) | (498) | (355) | (213) | (71) | |
| 7 | Return on Average Net Investment (B) | | Jan-Jun Jul-Dec | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.00% 2.03% | | (3) | (2) | (2) | (2) | (2) | (2) | (1) | (1) | (1) | (1) | 0 | 0 | (17) |
| | b. Equity Component Grossed Up For Taxes | | 8.27% 8.33% | | (11) | (10) | (9) | (8) | (7) | (6) | (5) | (4) | (3) | (2) | (1) | 0 | (66) |
| | c. Other | | | | 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 (A) | 33.3333% | | | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (142) | (1,706) |
| | c. Dismantlement | | | | N/A | N/A | N/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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | ($156) | ($154) | ($153) | ($152) | ($151) | ($150) | ($148) | ($147) | ($146) | ($145) | ($143) | ($142) | ($1,789) |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | ($156) | ($154) | ($153) | ($152) | ($151) | ($150) | ($148) | ($147) | ($146) | ($145) | ($143) | ($142) | ($1,789) |

(A) Investment amortized over three years in accordance with Order No. PSC-13-0381-PAA-EI.
(B) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Commission Forms 42-1P Through 42-8P**

**January 2016 - December 2016**
**Calculation of Projected Period Amount**

**Docket No. 150007-EI**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 14
PARTY: DUKE ENERGY FLORIDA, LLC
(DEF) – (DIRECT)
DESCRIPTION: Thomas G. Foster TGF-5

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

| 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) | $42,339,858 | $329,256 | $621,710 | $876,120 | $44,166,944 |
| b | Projected Capital Projects (Form 42-3P, Lines 7 through 9) | 22,049,877 | 0 | 1,414 | 3,176,702 | 25,227,993 |
| c | Total Jurisdictional Rev Req for the Projected Period (Lines 1a + 1b) | 64,389,735 | 329,256 | 623,124 | 4,052,822 | 69,394,937 |
| 2 | True-up for Estimated Over/(Under) Recovery for the Current Period January 2015 - December 2015 (Form 42-2E, Line 5 + 6 + 10) | (1,720,135) | (350,923) | 885,148 | 406,308 | (779,602) |
| 3 | Final True-up for the Period January 2014 - December 2014 (Form 42-1A, Line 3) | 1,428,470 | (98,371) | 4,238 | 84,706 | 1,419,043 |
| 4 | Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection Period January 2016 - December 2016 (Line 1 - Line 2 - Line 3) | 64,681,400 | 778,551 | (266,263) | 3,561,808 | 68,755,496 |
| 5 | Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072) | $64,727,970 | $779,111 | ($266,454) | $3,564,373 | $68,805,000 |

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**O&M Activities**
**(in Dollars)**

Form 42-2P

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)


| Line | Description | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | O&M Activities - System | | | | | | | | | | | | | |
| 1 | Transmission Substation Environmental Investigation, Remediation and Pollution Prevention | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $469,000 |
| 1a | Distribution Substation Environmental Investigation, Remediation and Pollution Prevention | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 621,000 |
| 2 | Distribution System Environmental Investigation, Remediation and Pollution Prevention | 3,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,000 |
| 3 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 51,723 | 51,723 | 51,723 | 51,723 | 695,676 |
| 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 | 8,824 | 8,824 | 10,978 | 8,657 | 9,562 | 9,661 | 9,921 | 9,934 | 9,931 | 8,793 | 7,740 | 8,223 | 111,050 |
| 5 | NOx Emissions Allowances Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 6 | Phase II Cooling Water Intake 316(b) - Base | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 250,000 |
| 6a | Phase II Cooling Water Intake 316(b) - Intm | 20,500 | 20,500 | 20,500 | 20,500 | 20,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 190,000 |
| 7.2 | CAIR/CAMR - Peaking | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 31,850 | 0 | 66,109 | 0 | 134,459 |
| 7.4 | CAIR/CAMR Crystal River - Base | 1,119,721 | 3,452,919 | 1,914,869 | 1,317,818 | 1,346,472 | 1,114,151 | 1,120,802 | 1,088,803 | 1,326,571 | 1,200,915 | 1,221,061 | 1,105,970 | 17,330,071 |
| 7.4 | CAIR/CAMR Crystal River - Energy | 1,421,824 | 1,336,488 | 1,001,927 | 1,382,142 | 1,426,980 | 1,465,949 | 1,456,055 | 1,483,137 | 1,483,419 | 1,514,175 | 1,311,791 | 1,499,939 | 16,783,826 |
| 7.4 | CAIR/CAMR Crystal River - A&G | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 141,192 |
| 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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Sea Turtle - Coastal Street Lighting - Distrib | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 50 | 50 | 50 | 0 | 0 | 450 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Energy | 0 | 0 | 18,232 | 0 | 4,290 | 7,500 | 0 | 0 | 18,232 | 0 | 4,290 | 7,500 | 60,044 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 48,283 | 48,283 | 43,283 | 43,283 | 529,400 |
| 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 | 266,003 | 266,003 | 406,003 | 542,253 | 366,003 | 266,003 | 302,253 | 266,003 | 266,003 | 302,253 | 266,003 | 266,003 | 3,780,792 |
| 18 | Coal Combustion Residual (CCR) Rule - Energy (C) | 150,333 | 75,333 | 75,333 | 294,083 | 294,083 | 294,083 | 294,083 | 75,333 | 75,333 | 75,333 | 50,333 | 50,333 | 1,804,000 |
| 2 | Total O&M Activities - Recoverable Costs | $3,512,115 | $5,718,478 | $3,994,753 | $4,087,364 | $3,989,901 | $3,716,858 | $3,717,624 | $3,457,671 | $3,766,426 | $3,631,555 | $3,452,362 | $3,488,005 | $46,533,115 |
| 3 | Recoverable Costs Allocated to Energy | 1,890,267 | 1,729,932 | 1,555,758 | 2,270,419 | 2,144,202 | 2,086,481 | 2,105,596 | 1,877,691 | 1,901,203 | 1,948,838 | 1,683,441 | 1,875,283 | 23,069,111 |
| | Recoverable Costs Allocated to Energy - NOx Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 4 | Recoverable Costs Allocated to Demand - Transm | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 469,000 |
| | Recoverable Costs Allocated to Demand - Distrib | 54,750 | 51,750 | 51,750 | 51,750 | 51,850 | 51,850 | 51,850 | 51,800 | 51,800 | 51,800 | 51,750 | 51,750 | 624,450 |
| | Recoverable Costs Allocated to Demand - Prod-Base | 1,132,221 | 3,465,419 | 1,952,369 | 1,330,318 | 1,358,972 | 1,151,651 | 1,133,302 | 1,101,303 | 1,364,071 | 1,213,415 | 1,233,561 | 1,143,470 | 17,580,071 |
| | Recoverable Costs Allocated to Demand - Prod-Intm | 81,598 | 81,598 | 81,598 | 81,598 | 81,598 | 73,598 | 73,598 | 73,598 | 64,223 | 64,223 | 64,223 | 64,223 | 885,676 |
| | Recoverable Costs Allocated to Demand - Prod-Peaking | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 31,850 | 0 | 66,109 | 0 | 134,459 |
| | Recoverable Costs Allocated to Demand - A&G | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 141,192 |
| 5 | Retail Energy Jurisdictional Factor | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | 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) | 1,849,176 | 1,689,187 | 1,529,691 | 2,220,389 | 2,084,201 | 2,025,099 | 2,037,318 | 1,812,034 | 1,837,596 | 1,884,537 | 1,627,322 | 1,831,640 | 22,428,190 |
| | Retail Energy Jurisdictional Factor - NOx Regulatory Asset (A) | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 8 | Jurisdictional Demand Recoverable Costs - Transm (B) | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 329,256 |
| | Jurisdictional Demand Recoverable Costs - Distrib (B) | 54,510 | 51,523 | 51,523 | 51,523 | 51,622 | 51,622 | 51,622 | 51,573 | 51,573 | 51,573 | 51,523 | 51,523 | 621,710 |
| | Jurisdictional Demand Recoverable Costs - Prod-Base (B) | 1,051,663 | 3,218,854 | 1,813,458 | 1,235,666 | 1,262,281 | 1,069,711 | 1,052,667 | 1,022,945 | 1,267,018 | 1,127,081 | 1,145,793 | 1,062,112 | 16,329,249 |
| | Jurisdictional Demand Recoverable Costs - Prod-Intm (B) | 59,324 | 59,324 | 59,324 | 59,324 | 59,324 | 53,508 | 53,508 | 53,508 | 46,692 | 46,692 | 46,692 | 46,692 | 643,912 |
| | Jurisdictional Demand Recoverable Costs - Prod-Peaking (B) | 0 | 35,012 | 0 | 0 | 0 | 0 | 0 | 0 | 30,552 | 0 | 63,414 | 0 | 128,978 |
| | Jurisdictional Demand Recoverable Costs - A&G (B) | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 131,616 |
| 9 | Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8) | $3,349,248 | $5,388,475 | $3,788,571 | $3,901,477 | $3,792,003 | $3,534,515 | $3,529,690 | $3,274,635 | $3,568,006 | $3,444,458 | $3,269,319 | $3,326,542 | $44,166,944 |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6
(C) As explained in the testimony of Garry Miller, $75K of 2015 temporary dust mitigation resulting from shift of permanent capital solution from October 2015 to October 2016 is included in Jan-16.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Capital Investment Projects-Recoverable Costs**
**(in Dollars)**

Form 42-3P

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)


| Line | Description | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investment Projects - System (A) | | | | | | | | | | | | | |
| 3.1 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| 4.1 | Above Ground Tank Secondary Containment - Peaking | 116,357 | 116,069 | 115,781 | 115,496 | 115,208 | 114,921 | 114,635 | 114,348 | 114,060 | 113,774 | 113,486 | 113,199 | 1,377,334 |
| 4.2 | Above Ground Tank Secondary Containment - Base | 24,937 | 24,911 | 24,885 | 24,858 | 24,832 | 24,806 | 24,780 | 24,754 | 24,728 | 24,702 | 24,676 | 24,649 | 297,518 |
| 4.3 | Above Ground Tank Secondary Containment - Intm | 2,700 | 2,696 | 2,691 | 2,687 | 2,683 | 2,678 | 2,674 | 2,669 | 2,664 | 2,660 | 2,655 | 2,650 | 32,107 |
| 5 | SO2/NOX Emissions Allowances - Energy | 90,075 | 87,387 | 84,690 | 81,995 | 79,305 | 76,610 | 73,915 | 71,217 | 68,521 | 65,828 | 63,146 | 60,466 | 903,155 |
| 7.1 | CAIR/CAMR Anclote- Intm | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.2 | CAIR/CAMR - Peaking | 18,804 | 18,775 | 18,745 | 18,711 | 18,684 | 18,651 | 18,622 | 18,590 | 18,558 | 18,531 | 18,499 | 18,468 | 223,638 |
| 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 | 42,190 | 43,219 | 43,666 | 44,115 | 44,563 | 45,007 | 45,456 | 45,904 | 46,348 | 46,797 | 47,246 | 47,692 | 542,203 |
| 7.4 | CAIR/CAMR Crystal River AFUDC - Energy | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 112,443 |
| 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 | 115 | 116 | 116 | 116 | 116 | 117 | 118 | 119 | 120 | 123 | 122 | 122 | 1,420 |
| 10.1 | Underground Storage Tanks - Base | 1,569 | 1,567 | 1,564 | 1,562 | 1,559 | 1,557 | 1,554 | 1,552 | 1,548 | 1,546 | 1,543 | 1,541 | 18,662 |
| 10.2 | Underground Storage Tanks - Intm | 733 | 731 | 730 | 728 | 726 | 725 | 722 | 721 | 720 | 717 | 716 | 714 | 8,683 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Intm | 154,003 | 153,692 | 153,383 | 153,073 | 152,763 | 152,453 | 152,143 | 151,833 | 151,523 | 151,214 | 150,903 | 150,593 | 1,827,576 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 37,668 | 37,612 | 37,555 | 37,499 | 37,443 | 37,386 | 37,330 | 37,273 | 37,217 | 37,160 | 37,103 | 37,047 | 448,291 |
| 17.1 | Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - | 1,430,070 | 1,427,963 | 1,425,857 | 1,423,751 | 1,421,646 | 1,419,540 | 1,417,433 | 1,415,327 | 1,413,221 | 1,411,115 | 1,409,009 | 1,406,902 | 17,021,828 |
| 17.2 | Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy | 246,827 | 250,632 | 257,005 | 262,083 | 263,275 | 279,122 | 278,455 | 277,789 | 277,122 | 276,456 | 275,790 | 275,123 | 3,219,684 |
| 18 | Coal Combustion Residual (CCR) Rule - Energy | (56,167) | 4,608 | 7,680 | 10,753 | 13,824 | 16,896 | 19,968 | 23,041 | 26,113 | 29,184 | 35,878 | 37,137 | 168,915 |
| 2 | Total Investment Projects - Recoverable Costs | $2,142,842 | $2,202,887 | $2,207,210 | $2,210,241 | $2,209,391 | $2,223,184 | $2,220,473 | $2,217,755 | $2,215,033 | $2,212,328 | $2,213,244 | $2,208,729 | $26,483,317 |
| 3 | Recoverable Costs Allocated to Energy | 1,757,843 | 1,817,572 | 1,822,157 | 1,825,451 | 1,824,863 | 1,838,924 | 1,836,471 | 1,834,017 | 1,831,564 | 1,829,113 | 1,830,296 | 1,826,045 | 21,874,316 |
| | Recoverable Costs Allocated to Distribution Demand | 115 | 116 | 116 | 116 | 116 | 117 | 118 | 119 | 120 | 123 | 122 | 122 | 1,420 |
| 4 | Recoverable Costs Allocated to Demand - Production - Base | 68,696 | 69,697 | 70,115 | 70,535 | 70,954 | 71,370 | 71,790 | 72,210 | 72,624 | 73,045 | 73,465 | 73,882 | 858,383 |
| | Recoverable Costs Allocated to Demand - Production - Intermediate | 181,027 | 180,658 | 180,296 | 179,932 | 179,566 | 179,201 | 178,837 | 178,471 | 178,107 | 177,742 | 177,376 | 177,013 | 2,148,226 |
| | Recoverable Costs Allocated to Demand - Production - Peaking | 135,161 | 134,844 | 134,526 | 134,207 | 133,892 | 133,572 | 133,257 | 132,938 | 132,618 | 132,305 | 131,985 | 131,667 | 1,600,972 |
| | Recoverable Costs Allocated to Demand - Production - Base (2012) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | Retail Energy Jurisdictional Factor | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | 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) | 1,719,630 | 1,774,762 | 1,791,627 | 1,785,225 | 1,773,798 | 1,784,825 | 1,776,920 | 1,769,887 | 1,770,287 | 1,768,762 | 1,769,281 | 1,783,548 | 21,268,554 |
| | Jurisdictional Demand Recoverable Costs - Distribution (B) | 114 | 115 | 115 | 115 | 115 | 116 | 117 | 118 | 119 | 122 | 121 | 121 | 1,414 |
| 8 | Jurisdictional Demand Recoverable Costs - Production - Base (C) | 63,808 | 64,738 | 65,126 | 65,516 | 65,906 | 66,292 | 66,682 | 67,072 | 67,457 | 67,848 | 68,238 | 68,625 | 797,309 |
| | Jurisdictional Demand Recoverable Costs - Production - Intermediate (C) | 131,612 | 131,344 | 131,081 | 130,816 | 130,550 | 130,285 | 130,020 | 129,754 | 129,489 | 129,224 | 128,958 | 128,694 | 1,561,825 |
| | Jurisdictional Demand Recoverable Costs - Production - Peaking (C) | 129,652 | 129,348 | 129,043 | 128,737 | 128,435 | 128,128 | 127,825 | 127,519 | 127,212 | 126,912 | 126,605 | 126,300 | 1,535,716 |
| | Jurisdictional Demand Recoverable Costs - Production - Base (2012) (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8) | $2,044,817 | $2,100,308 | $2,116,992 | $2,110,410 | $2,098,803 | $2,109,646 | $2,101,565 | $2,094,351 | $2,094,565 | $2,092,869 | $2,093,204 | $2,107,289 | $25,164,818 |

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, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | |
| 3 | Less: Accumulated Depreciation | (777,505) | (783,149) | (788,793) | (794,437) | (800,081) | (805,725) | (811,369) | (817,013) | (822,657) | (828,301) | (833,945) | (839,589) | (845,233) | |
| 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) | $1,837,200 | $1,831,556 | $1,825,912 | $1,820,268 | $1,814,624 | $1,808,980 | $1,803,336 | $1,797,692 | $1,792,048 | $1,786,404 | $1,780,760 | $1,775,116 | $1,769,472 | |
| 6 | Average Net Investment | | $1,834,378 | $1,828,734 | $1,823,090 | $1,817,446 | $1,811,802 | $1,806,158 | $1,800,514 | $1,794,870 | $1,789,226 | $1,783,582 | $1,777,938 | $1,772,294 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 3,098 | 3,087 | 3,078 | 3,069 | 3,059 | 3,050 | 3,040 | 3,031 | 3,021 | 3,012 | 3,002 | 2,994 | 36,541 |
| | b. Equity Component Grossed Up For Taxes | | 12,742 | 12,701 | 12,663 | 12,624 | 12,584 | 12,544 | 12,507 | 12,466 | 12,428 | 12,388 | 12,349 | 12,311 | 150,307 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 67,728 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 25,284 |
| | e. Other (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| 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) | | 17,151 | 17,114 | 17,079 | 17,044 | 17,008 | 16,973 | 16,938 | 16,902 | 16,867 | 16,831 | 16,796 | 16,762 | 203,467 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $17,151 | $17,114 | $17,079 | $17,044 | $17,008 | $16,973 | $16,938 | $16,902 | $16,867 | $16,831 | $16,796 | $16,762 | $203,467 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | |
| 3 | Less: Accumulated Depreciation | (2,805,915) | (2,839,142) | (2,872,369) | (2,905,596) | (2,938,823) | (2,972,050) | (3,005,277) | (3,038,504) | (3,071,731) | (3,104,958) | (3,138,185) | (3,171,412) | (3,204,639) | |
| 4 | CWIP - Non-Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $8,495,889 | $8,462,662 | $8,429,435 | $8,396,208 | $8,362,981 | $8,329,754 | $8,296,527 | $8,263,300 | $8,230,073 | $8,196,846 | $8,163,619 | $8,130,392 | $8,097,165 | |
| 6 | Average Net Investment | | $8,479,275 | $8,446,048 | $8,412,821 | $8,379,594 | $8,346,367 | $8,313,140 | $8,279,913 | $8,246,686 | $8,213,459 | $8,180,232 | $8,147,005 | $8,113,778 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 14,317 | 14,261 | 14,205 | 14,148 | 14,093 | 14,037 | 13,980 | 13,924 | 13,867 | 13,812 | 13,755 | 13,699 | 168,098 |
| | b. Equity Component Grossed Up For Taxes | | 58,896 | 58,664 | 58,432 | 58,204 | 57,971 | 57,740 | 57,511 | 57,280 | 57,049 | 56,818 | 56,587 | 56,356 | 691,508 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 398,724 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 119,004 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $116,357 | $116,069 | $115,781 | $115,496 | $115,208 | $114,921 | $114,635 | $114,348 | $114,060 | $113,774 | $113,486 | $113,199 | $1,377,334 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $116,357 | $116,069 | $115,781 | $115,496 | $115,208 | $114,921 | $114,635 | $114,348 | $114,060 | $113,774 | $113,486 | $113,199 | $1,377,334 |
| 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) | | 111,614 | 111,338 | 111,062 | 110,788 | 110,512 | 110,237 | 109,962 | 109,687 | 109,411 | 109,137 | 108,860 | 108,585 | 1,321,194 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $111,614 | $111,338 | $111,062 | $110,788 | $110,512 | $110,237 | $109,962 | $109,687 | $109,411 | $109,137 | $108,860 | $108,585 | $1,321,194 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | 100,001 | 96,969 | 93,937 | 90,905 | 87,873 | 84,841 | 81,809 | 78,777 | 75,745 | 72,713 | 69,681 | 66,649 | 63,617 | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | $2,499,040 | $2,496,008 | $2,492,976 | $2,489,944 | $2,486,912 | $2,483,880 | $2,480,848 | $2,477,816 | $2,474,784 | $2,471,752 | $2,468,720 | $2,465,688 | $2,462,656 | |
| 6 | Average Net Investment | | $2,497,524 | $2,494,492 | $2,491,460 | $2,488,428 | $2,485,396 | $2,482,364 | $2,479,332 | $2,476,300 | $2,473,268 | $2,470,236 | $2,467,204 | $2,464,172 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 4,217 | 4,212 | 4,207 | 4,201 | 4,196 | 4,191 | 4,186 | 4,181 | 4,177 | 4,171 | 4,166 | 4,161 | 50,266 |
| | b. Equity Component Grossed Up For Taxes | | 17,347 | 17,326 | 17,305 | 17,284 | 17,263 | 17,242 | 17,221 | 17,200 | 17,178 | 17,158 | 17,137 | 17,115 | 206,776 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 36,384 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 4,092 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $24,937 | $24,911 | $24,885 | $24,858 | $24,832 | $24,806 | $24,780 | $24,754 | $24,728 | $24,702 | $24,676 | $24,649 | $297,518 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $24,937 | $24,911 | $24,885 | $24,858 | $24,832 | $24,806 | $24,780 | $24,754 | $24,728 | $24,702 | $24,676 | $24,649 | $297,518 |
| 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) | | 23,163 | 23,139 | 23,114 | 23,089 | 23,065 | 23,041 | 23,017 | 22,993 | 22,969 | 22,944 | 22,920 | 22,895 | 276,350 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $23,163 | $23,139 | $23,114 | $23,089 | $23,065 | $23,041 | $23,017 | $22,993 | $22,969 | $22,944 | $22,920 | $22,895 | $276,350 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | (60,186) | (60,711) | (61,236) | (61,761) | (62,286) | (62,811) | (63,336) | (63,861) | (64,386) | (64,911) | (65,436) | (65,961) | (66,486) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | $230,112 | $229,587 | $229,062 | $228,537 | $228,012 | $227,487 | $226,962 | $226,437 | $225,912 | $225,387 | $224,862 | $224,337 | $223,812 | |
| 6 | Average Net Investment | | $229,849 | $229,324 | $228,799 | $228,274 | $227,749 | $227,224 | $226,699 | $226,174 | $225,649 | $225,124 | $224,599 | $224,074 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 388 | 387 | 386 | 385 | 385 | 384 | 383 | 382 | 381 | 380 | 379 | 378 | 4,598 |
| | b. Equity Component Grossed Up For Taxes | | 1,596 | 1,593 | 1,589 | 1,586 | 1,582 | 1,578 | 1,575 | 1,571 | 1,567 | 1,564 | 1,560 | 1,556 | 18,917 |
| | 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) | | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 2,292 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |
| 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) | | 1,963 | 1,960 | 1,956 | 1,954 | 1,951 | 1,947 | 1,944 | 1,940 | 1,937 | 1,934 | 1,930 | 1,927 | 23,343 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $1,963 | $1,960 | $1,956 | $1,954 | $1,951 | $1,947 | $1,944 | $1,940 | $1,937 | $1,934 | $1,930 | $1,927 | $23,343 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0158150 $SO_2$ Emission Allowance Inventory | | $3,333,608 | $3,324,785 | $3,315,961 | $3,304,982 | $3,296,584 | $3,287,013 | $3,277,343 | $3,267,414 | $3,257,471 | $3,247,532 | $3,238,730 | $3,230,982 | $3,222,750 | $3,222,750 |
| | b. 0254020 Auctioned $SO_2$ Allowance | | (4,039) | (4,039) | (4,039) | (4,039) | (4,298) | (4,289) | (4,281) | (4,272) | (4,264) | (4,256) | (4,247) | (4,239) | (4,230) | (4,230) |
| | c. 0158170 NOx Emission Allowance Inventory | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Other (A) | | 7,258,313 | 6,955,883 | 6,653,453 | 6,351,024 | 6,048,594 | 5,746,164 | 5,443,735 | 5,141,305 | 4,838,875 | 4,536,446 | 4,234,016 | 3,931,586 | 3,629,156 | 3,629,156 |
| 2 | Total Working Capital | | $10,587,882 | $10,276,629 | $9,965,375 | $9,651,967 | $9,340,880 | $9,028,888 | $8,716,797 | $8,404,447 | $8,092,083 | $7,779,722 | $7,468,499 | $7,158,329 | $6,847,676 | $6,847,676 |
| 3 | Average Net Investment | | | $10,432,255 | $10,121,002 | $9,808,671 | $9,496,424 | $9,184,884 | $8,872,843 | $8,560,622 | $8,248,265 | $7,935,902 | $7,624,110 | $7,313,414 | $7,003,003 | |
| 4 | Return on Average Net Working Capital Balance (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 17,615 | 17,089 | 16,562 | 16,035 | 15,509 | 14,982 | 14,455 | 13,927 | 13,400 | 12,873 | 12,349 | 11,825 | 176,621 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 72,460 | 70,298 | 68,128 | 65,960 | 63,796 | 61,628 | 59,460 | 57,290 | 55,121 | 52,955 | 50,797 | 48,641 | 726,534 |
| 5 | Total Return Component (C) | | | $90,075 | $87,387 | $84,690 | $81,995 | $79,305 | $76,610 | $73,915 | $71,217 | $68,521 | $65,828 | $63,146 | $60,466 | 903,155 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0509030 $SO_2$ Allowance Expense | | | $8,824 | $8,824 | $10,978 | $8,399 | $9,571 | $9,670 | $9,929 | $9,943 | $9,940 | $8,802 | $7,748 | $8,232 | 110,858 |
| | b. 0407426 Amortization Expense | | | 0 | 0 | 0 | 259 | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | 191 |
| | 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) | | | 8,824 | 8,824 | 10,978 | 8,657 | 9,562 | 9,661 | 9,921 | 9,934 | 9,931 | 8,793 | 7,740 | 8,223 | 111,050 |
| 8 | Amortization of NOx CAIR Emission Allowances (A) | | | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | 3,629,156 |
| 9 | Total System Recoverable Expenses (Lines 5 + 7) | | | $401,328 | $398,641 | $398,098 | $393,082 | $391,297 | $388,701 | $386,265 | $383,581 | $380,882 | $377,051 | $373,316 | $371,119 | |
| | a. Recoverable Costs Allocated to Energy | | | 98,899 | 96,211 | 95,668 | 90,652 | 88,867 | 86,271 | 83,836 | 81,151 | 78,452 | 74,621 | 70,886 | 68,689 | |
| | b. Recoverable Costs Allocated to Energy - NOx CAIR Emisssion Allowances (A) | | | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | |
| 10 | a. Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | b. NOx Regulatory Asset Energy Factor (12/2014) (A) | | | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | |
| 11 | Retail Energy-Related Recoverable Costs (E) | | | $96,749 | $93,945 | $94,065 | $88,654 | $86,381 | $83,733 | $81,117 | $78,314 | $75,828 | $72,159 | $68,523 | $67,091 | 986,559 |
| 12 | Retail Demand-Related Recoverable Costs (F) | | | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 13 | Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | | $ 392,918 | $ 390,114 | $ 390,235 | $ 384,824 | $ 382,550 | $ 379,903 | $ 377,287 | $ 374,483 | $ 371,997 | $ 368,329 | $ 364,692 | $ 363,260 | $ 4,540,592 |

Notes:

(A) Unusable NOx emission allowances due expiration of Clean Air Interstate Rule (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 conisistent with Order No. PSC-11-0553-FOF-EI.

(B) Line 3 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) Line 5 is reported on Capital Schedule

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

(E) Line 9a x Line 10a

(F) Line 9b x Line 10b

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | |
| 3 | Less: Accumulated Depreciation | (346,416) | (349,966) | (353,516) | (357,066) | (360,616) | (364,166) | (367,716) | (371,266) | (374,816) | (378,366) | (381,916) | (385,466) | (389,016) | |
| 4 | CWIP - Non-Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $1,589,692 | $1,586,142 | $1,582,592 | $1,579,042 | $1,575,492 | $1,571,942 | $1,568,392 | $1,564,842 | $1,561,292 | $1,557,742 | $1,554,192 | $1,550,642 | $1,547,092 | |
| 6 | Average Net Investment | | $1,587,917 | $1,584,367 | $1,580,817 | $1,577,267 | $1,573,717 | $1,570,167 | $1,566,617 | $1,563,067 | $1,559,517 | $1,555,967 | $1,552,417 | $1,548,867 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 2,680 | 2,675 | 2,670 | 2,662 | 2,658 | 2,651 | 2,646 | 2,639 | 2,632 | 2,629 | 2,621 | 2,614 | 31,777 |
| | b. Equity Component Grossed Up For Taxes | | 11,029 | 11,005 | 10,980 | 10,954 | 10,931 | 10,905 | 10,881 | 10,856 | 10,831 | 10,807 | 10,783 | 10,759 | 130,721 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 42,600 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 18,540 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $18,804 | $18,775 | $18,745 | $18,711 | $18,684 | $18,651 | $18,622 | $18,590 | $18,558 | $18,531 | $18,499 | $18,468 | 223,638 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $18,804 | $18,775 | $18,745 | $18,711 | $18,684 | $18,651 | $18,622 | $18,590 | $18,558 | $18,531 | $18,499 | $18,468 | 223,638 |
| 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) | | 18,038 | 18,010 | 17,981 | 17,948 | 17,922 | 17,891 | 17,863 | 17,832 | 17,802 | 17,776 | 17,745 | 17,715 | 214,523 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $18,038 | $18,010 | $17,981 | $17,948 | $17,922 | $17,891 | $17,863 | $17,832 | $17,802 | $17,776 | $17,745 | $17,715 | $214,523 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $713,122 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | |
| 3 | Less: Accumulated Depreciation | (106,469) | (114,097) | (121,725) | (129,353) | (136,981) | (144,609) | (152,237) | (159,865) | (167,493) | (175,121) | (182,749) | (190,377) | (198,005) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 59,427 | 118,854 | 178,281 | 237,707 | 297,134 | 356,561 | 415,988 | 475,415 | 534,842 | 594,268 | 653,695 | 713,122 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $3,844,399 | $3,896,197 | $3,947,996 | $3,999,795 | $4,051,594 | $4,103,393 | $4,155,192 | $4,206,990 | $4,258,789 | $4,310,588 | $4,362,387 | $4,414,186 | $4,465,985 | |
| 6 | Average Net Investment | | $3,870,298 | $3,922,097 | $3,973,896 | $4,025,694 | $4,077,493 | $4,129,292 | $4,181,091 | $4,232,890 | $4,284,689 | $4,336,487 | $4,388,286 | $4,440,085 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 6,649 | 6,850 | 6,938 | 7,026 | 7,114 | 7,199 | 7,288 | 7,376 | 7,462 | 7,550 | 7,638 | 7,725 | 86,815 |
| | b. Equity Component Grossed Up For Taxes | | 27,352 | 28,180 | 28,539 | 28,900 | 29,260 | 29,619 | 29,979 | 30,339 | 30,697 | 31,058 | 31,419 | 31,778 | 357,120 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 91,536 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (D) | | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 6,732 |
| | e. Other | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $42,190 | $43,219 | $43,666 | $44,115 | $44,563 | $45,007 | $45,456 | $45,904 | $46,348 | $46,797 | $47,246 | $47,692 | 542,203 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $42,190 | $43,219 | $43,666 | $44,115 | $44,563 | $45,007 | $45,456 | $45,904 | $46,348 | $46,797 | $47,246 | $47,692 | 542,203 |
| 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) | | 39,188 | 40,144 | 40,559 | 40,976 | 41,392 | 41,805 | 42,222 | 42,638 | 43,050 | 43,467 | 43,884 | 44,299 | 503,625 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $39,188 | $40,144 | $40,559 | $40,976 | $41,392 | $41,805 | $42,222 | $42,638 | $43,050 | $43,467 | $43,884 | $44,299 | $503,625 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**Schedule of Amortization and Return**
**For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-Products)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0154401 Ammonia Inventory | | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | 185,206 |
| | b. 0154200 Limestone Inventory | | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 |
| 2 | Total Working Capital | | $1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 |
| 3 | Average Net Investment | | | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | |
| 4 | Return on Average Net Working Capital Balance (A) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | $21,989 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 90,454 |
| 5 | Total Return Component (B) | | | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 112,443 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0502010 Ammonia Expense | | | 455,485 | 425,538 | 297,964 | 432,747 | 455,824 | 459,359 | 470,739 | 467,246 | 474,561 | 484,937 | 413,592 | 472,009 | 5,310,002 |
| | b. 0502040 Limestone Expense | | | 447,356 | 418,943 | 294,169 | 428,890 | 452,848 | 457,804 | 470,373 | 468,108 | 476,919 | 488,404 | 417,340 | 476,024 | 5,297,179 |
| | c. 0502050 Dibasic Acid Expense | | | 0 | 0 | 22,000 | 0 | 0 | 22,000 | 0 | 22,000 | 0 | 0 | 0 | 22,000 | 88,000 |
| | d. 0502070 Gypsum Disposal/Sale | | | 101,740 | 99,311 | 99,311 | 123,599 | 102,010 | 106,867 | 85,008 | 99,311 | 99,311 | 99,311 | 99,311 | 99,311 | 1,214,400 |
| | e. 0502040 Hydrated Lime Expense | | | 392,243 | 367,696 | 263,483 | 371,906 | 391,298 | 394,918 | 404,935 | 401,472 | 407,628 | 416,522 | 356,548 | 405,595 | 4,574,245 |
| | f. 0502300 Caustic Expense | | | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 300,000 |
| 7 | Net Expense (C) | | | 1,421,824 | 1,336,488 | 1,001,927 | 1,382,142 | 1,426,980 | 1,465,949 | 1,456,055 | 1,483,137 | 1,483,419 | 1,514,175 | 1,311,791 | 1,499,939 | 16,783,826 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | | $1,431,194 | $1,345,858 | $1,011,298 | $1,391,513 | $1,436,350 | $1,475,319 | $1,465,425 | $1,492,507 | $1,492,790 | $1,523,545 | $1,321,161 | $1,509,309 | $16,896,268 |
| | a. Recoverable Costs Allocated to Energy | | | 1,431,194 | 1,345,858 | 1,011,298 | 1,391,513 | 1,436,350 | 1,475,319 | 1,465,425 | 1,492,507 | 1,492,790 | 1,523,545 | 1,321,161 | 1,509,309 | 16,896,268 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | 1,400,082 | 1,314,159 | 994,353 | 1,360,849 | 1,396,157 | 1,431,917 | 1,417,906 | 1,440,318 | 1,442,847 | 1,473,276 | 1,277,119 | 1,474,184 | 16,423,168 |
| 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) | | | $ 1,400,082 | $ 1,314,159 | $ 994,353 | $ 1,360,849 | $ 1,396,157 | $ 1,431,917 | $ 1,417,906 | $ 1,440,318 | $ 1,442,847 | $ 1,473,276 | $ 1,277,119 | $ 1,474,184 | $ 16,423,168 |

Notes:

(A) Line 3 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $150 | $150 | $150 | $150 | $150 | $0 | $0 | $0 | $750 |
| | b. Clearings to Plant | | 300 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 750 | 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 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 12,374 | 12,374 | 12,374 | 12,374 | |
| 3 | Less: Accumulated Depreciation | (2,655) | (2,684) | (2,714) | (2,744) | (2,774) | (2,804) | (2,834) | (2,864) | (2,894) | (2,924) | (2,956) | (2,988) | (3,020) | |
| 4 | CWIP - Non-Interest Bearing | 300 | 0 | 0 | 0 | 0 | 150 | 300 | 450 | 600 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $8,969 | $8,940 | $8,910 | $8,880 | $8,850 | $8,970 | $9,090 | $9,210 | $9,330 | $9,450 | $9,418 | $9,386 | $9,354 | |
| 6 | Average Net Investment | | $8,954 | $8,925 | $8,895 | $8,865 | $8,910 | $9,030 | $9,150 | $9,270 | $9,390 | $9,434 | $9,402 | $9,370 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component 2.03% | | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 16 | 16 | 16 | 16 | 16 | 185 |
| | b. Equity Component Grossed Up For Taxes 8.33% | | 62 | 62 | 62 | 62 | 62 | 63 | 64 | 64 | 65 | 66 | 65 | 65 | 762 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) 3.0658% | | 29 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 32 | 32 | 32 | 365 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/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) 0.009035 | | 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) | | $115 | $116 | $116 | $116 | $116 | $117 | $118 | $119 | $120 | $123 | $122 | $122 | 1,420 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $115 | $116 | $116 | $116 | $116 | $117 | $118 | $119 | $120 | $123 | $122 | $122 | 1,420 |
| 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) | | 114 | 115 | 115 | 115 | 115 | 116 | 117 | 118 | 119 | 122 | 121 | 121 | 1,414 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $114 | $115 | $115 | $115 | $115 | $116 | $117 | $118 | $119 | $122 | $121 | $121 | $1,414 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | (35,344) | (35,640) | (35,936) | (36,232) | (36,528) | (36,824) | (37,120) | (37,416) | (37,712) | (38,008) | (38,304) | (38,600) | (38,896) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $133,597 | $133,301 | $133,005 | $132,709 | $132,413 | $132,117 | $131,821 | $131,525 | $131,229 | $130,933 | $130,637 | $130,341 | $130,045 | |
| 6 | Average Net Investment | | | $133,449 | $133,153 | $132,857 | $132,561 | $132,265 | $131,969 | $131,673 | $131,377 | $131,081 | $130,785 | $130,489 | $130,193 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 225 | 225 | 224 | 224 | 223 | 223 | 222 | 222 | 221 | 221 | 220 | 220 | 2,670 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 927 | 925 | 923 | 921 | 919 | 917 | 915 | 913 | 910 | 908 | 906 | 904 | 10,988 |
| | 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) | | | $1,569 | $1,567 | $1,564 | $1,562 | $1,559 | $1,557 | $1,554 | $1,552 | $1,548 | $1,546 | $1,543 | $1,541 | 18,662 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $1,569 | $1,567 | $1,564 | $1,562 | $1,559 | $1,557 | $1,554 | $1,552 | $1,548 | $1,546 | $1,543 | $1,541 | 18,662 |
| 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) | | | 1,457 | 1,456 | 1,453 | 1,451 | 1,448 | 1,446 | 1,443 | 1,442 | 1,438 | 1,436 | 1,433 | 1,431 | 17,334 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $1,457 | $1,456 | $1,453 | $1,451 | $1,448 | $1,446 | $1,443 | $1,442 | $1,438 | $1,436 | $1,433 | $1,431 | $17,334 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | (21,785) | (21,988) | (22,191) | (22,394) | (22,597) | (22,800) | (23,003) | (23,206) | (23,409) | (23,612) | (23,815) | (24,018) | (24,221) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $54,221 | $54,018 | $53,815 | $53,612 | $53,409 | $53,206 | $53,003 | $52,800 | $52,597 | $52,394 | $52,191 | $51,988 | $51,785 | |
| 6 | Average Net Investment | | | $54,120 | $53,917 | $53,714 | $53,511 | $53,308 | $53,105 | $52,902 | $52,699 | $52,496 | $52,293 | $52,090 | $51,887 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 91 | 91 | 91 | 90 | 90 | 90 | 89 | 89 | 89 | 88 | 88 | 88 | 1,074 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 376 | 374 | 373 | 372 | 370 | 369 | 367 | 366 | 365 | 363 | 362 | 360 | 4,417 |
| | 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) | | | $733 | $731 | $730 | $728 | $726 | $725 | $722 | $721 | $720 | $717 | $716 | $714 | 8,683 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $733 | $731 | $730 | $728 | $726 | $725 | $722 | $721 | $720 | $717 | $716 | $714 | 8,683 |
| 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) | | | 533 | 531 | 531 | 529 | 528 | 527 | 525 | 524 | 523 | 521 | 521 | 519 | 6,313 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $533 | $531 | $531 | $529 | $528 | $527 | $525 | $524 | $523 | $521 | $521 | $519 | $6,313 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | |
| 3 | Less: Accumulated Depreciation | | (431,137) | (467,033) | (502,929) | (538,825) | (574,721) | (610,617) | (646,513) | (682,409) | (718,305) | (754,201) | (790,097) | (825,993) | (861,889) | |
| 4 | CWIP - Non-Interest Bearing | | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $12,463,374 | $12,427,478 | $12,391,582 | $12,355,686 | $12,319,790 | $12,283,894 | $12,247,998 | $12,212,102 | $12,176,206 | $12,140,310 | $12,104,414 | $12,068,518 | $12,032,622 | |
| 6 | Average Net Investment | | | $12,445,426 | $12,409,530 | $12,373,634 | $12,337,738 | $12,301,842 | $12,265,946 | $12,230,050 | $12,194,154 | $12,158,258 | $12,122,362 | $12,086,466 | $12,050,570 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 21,014 | 20,953 | 20,893 | 20,832 | 20,772 | 20,711 | 20,650 | 20,590 | 20,529 | 20,469 | 20,408 | 20,347 | 248,168 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 86,443 | 86,193 | 85,944 | 85,695 | 85,445 | 85,196 | 84,947 | 84,697 | 84,448 | 84,199 | 83,949 | 83,700 | 1,020,856 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.3333% | | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 430,752 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (D) | 0.009890 | | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 127,800 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $154,003 | $153,692 | $153,383 | $153,073 | $152,763 | $152,453 | $152,143 | $151,833 | $151,523 | $151,214 | $150,903 | $150,593 | 1,827,576 |
| | 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 | | | $154,003 | $153,692 | $153,383 | $153,073 | $152,763 | $152,453 | $152,143 | $151,833 | $151,523 | $151,214 | $150,903 | $150,593 | 1,827,576 |
| 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 - 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) | | | 111,965 | 111,739 | 111,514 | 111,289 | 111,063 | 110,838 | 110,613 | 110,387 | 110,162 | 109,937 | 109,711 | 109,486 | 1,328,703 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $111,965 | $111,739 | $111,514 | $111,289 | $111,063 | $110,838 | $110,613 | $110,387 | $110,162 | $109,937 | $109,711 | $109,486 | $1,328,703 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 1
(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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
Page 17 of 45

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | |
| 3 | Less: Accumulated Depreciation | | (47,336) | (53,873) | (60,411) | (66,948) | (73,486) | (80,023) | (86,561) | (93,098) | (99,636) | (106,173) | (112,710) | (119,248) | (125,785) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $3,617,607 | $3,611,069 | $3,604,532 | $3,597,994 | $3,591,457 | $3,584,919 | $3,578,382 | $3,571,845 | $3,565,307 | $3,558,770 | $3,552,232 | $3,545,695 | $3,539,157 | |
| 6 | Average Net Investment | | | $3,614,338 | $3,607,801 | $3,601,263 | $3,594,726 | $3,588,188 | $3,581,651 | $3,575,113 | $3,568,576 | $3,562,038 | $3,555,501 | $3,548,963 | $3,542,426 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 6,103 | 6,092 | 6,081 | 6,070 | 6,059 | 6,048 | 6,037 | 6,026 | 6,015 | 6,003 | 5,992 | 5,981 | 72,507 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 25,104 | 25,059 | 25,013 | 24,968 | 24,923 | 24,877 | 24,832 | 24,786 | 24,741 | 24,696 | 24,650 | 24,605 | 298,254 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | Blended | | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 78,449 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 6,241 |
| | 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) | | | $37,668 | $37,612 | $37,555 | $37,499 | $37,443 | $37,386 | $37,330 | $37,273 | $37,217 | $37,160 | $37,103 | $37,047 | 448,291 |
| | a. Recoverable Costs Allocated to Energy | | | 37,668 | 37,612 | 37,555 | 37,499 | 37,443 | 37,386 | 37,330 | 37,273 | 37,217 | 37,160 | 37,103 | 37,047 | 448,291 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $36,849 | $36,726 | $36,926 | $36,673 | $36,395 | $36,286 | $36,119 | $35,970 | $35,972 | $35,934 | $35,866 | $36,185 | $435,901 |
| 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) | | | $36,849 | $36,726 | $36,926 | $36,673 | $36,395 | $36,286 | $36,119 | $35,970 | $35,972 | $35,934 | $35,866 | $36,185 | $435,901 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | |
| 3 | Less: Accumulated Depreciation | | (5,824,679) | (6,068,599) | (6,312,519) | (6,556,439) | (6,800,359) | (7,044,279) | (7,288,199) | (7,532,119) | (7,776,039) | (8,019,959) | (8,263,879) | (8,507,799) | (8,751,719) | |
| 4 | CWIP - AFUDC Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $128,925,596 | $128,681,676 | $128,437,756 | $128,193,836 | $127,949,916 | $127,705,996 | $127,462,076 | $127,218,156 | $126,974,236 | $126,730,316 | $126,486,396 | $126,242,476 | $125,998,556 | |
| 6 | Average Net Investment | | | $128,803,636 | $128,559,716 | $128,315,796 | $128,071,876 | $127,827,956 | $127,584,036 | $127,340,116 | $127,096,196 | $126,852,276 | $126,608,356 | $126,364,436 | $126,120,516 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 217,485 | 217,073 | 216,661 | 216,249 | 215,838 | 215,426 | 215,014 | 214,602 | 214,190 | 213,778 | 213,366 | 212,954 | 2,582,636 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 894,636 | 892,941 | 891,247 | 889,553 | 887,859 | 886,165 | 884,470 | 882,776 | 881,082 | 879,388 | 877,694 | 875,999 | 10,623,810 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.1722% | | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 2,927,040 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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) | 0.007910 | | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 1,065,876 |
| | 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) | | | $1,430,070 | $1,427,963 | $1,425,857 | $1,423,751 | $1,421,646 | $1,419,540 | $1,417,433 | $1,415,327 | $1,413,221 | $1,411,115 | $1,409,009 | $1,406,902 | 17,021,828 |
| | a. Recoverable Costs Allocated to Energy | | | 1,430,070 | 1,427,963 | 1,425,857 | 1,423,751 | 1,421,646 | 1,419,540 | 1,417,433 | 1,415,327 | 1,413,221 | 1,411,115 | 1,409,009 | 1,406,902 | 17,021,828 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $1,398,982 | $1,394,329 | $1,401,967 | $1,392,377 | $1,381,864 | $1,377,778 | $1,371,470 | $1,365,837 | $1,365,940 | $1,364,555 | $1,362,038 | $1,374,159 | $16,551,296 |
| 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) | | | $1,398,982 | $1,394,329 | $1,401,967 | $1,392,377 | $1,381,864 | $1,377,778 | $1,371,470 | $1,365,837 | $1,365,940 | $1,364,555 | $1,362,038 | $1,374,159 | $16,551,296 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $600,000 | $600,000 | $1,000,000 | $300,000 | $100,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,600,000 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 4,965,495 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | (194,715) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $20,070,225 | 20,070,225 | 20,070,225 | 20,070,225 | 20,070,225 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | |
| 3 | Less: Accumulated Depreciation | | (491,482) | (553,365) | (615,248) | (677,131) | (739,014) | (800,897) | (878,090) | (955,283) | (1,032,476) | (1,109,669) | (1,186,862) | (1,264,055) | (1,341,248) | |
| 4 | CWIP - Non-Interest Bearing | | 2,560,209 | 2,965,495 | 3,565,495 | 4,565,495 | 4,865,495 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $22,138,952 | $22,482,354 | $23,020,471 | $23,958,588 | $24,196,705 | $24,234,822 | $24,157,629 | $24,080,436 | $24,003,243 | $23,926,050 | $23,848,857 | $23,771,664 | $23,694,471 | |
| 6 | Average Net Investment | | | $22,310,653 | $22,751,413 | $23,489,530 | $24,077,647 | $24,215,764 | $24,196,226 | $24,119,033 | $24,041,840 | $23,964,647 | $23,887,454 | $23,810,261 | $23,733,068 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 37,672 | 38,416 | 39,662 | 40,655 | 40,888 | 40,855 | 40,725 | 40,595 | 40,464 | 40,334 | 40,204 | 40,073 | 480,543 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 154,964 | 158,025 | 163,152 | 167,237 | 168,196 | 168,061 | 167,524 | 166,988 | 166,452 | 165,916 | 165,380 | 164,844 | 1,976,739 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.7000% | | 61,883 | 61,883 | 61,883 | 61,883 | 61,883 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 849,766 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | | 2,848 | 2,848 | 2,848 | 2,848 | 2,848 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 39,111 |
| | 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) | | | $246,827 | $250,632 | $257,005 | $262,083 | $263,275 | $279,122 | $278,455 | $277,789 | $277,122 | $276,456 | $275,790 | $275,123 | 3,219,684 |
| | a. Recoverable Costs Allocated to Energy | | | 246,827 | 250,632 | 257,005 | 262,083 | 263,275 | 279,122 | 278,455 | 277,789 | 277,122 | 276,456 | 275,790 | 275,123 | 3,219,684 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $241,462 | $244,729 | $252,699 | $256,308 | $255,908 | $270,911 | $269,426 | $268,076 | $267,851 | $267,335 | $266,597 | $268,720 | $3,130,022 |
| 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) | | | $241,462 | $244,729 | $252,699 | $256,308 | $255,908 | $270,911 | $269,426 | $268,076 | $267,851 | $267,335 | $266,597 | $268,720 | $3,130,022 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Return on Capital Investments, Depreciation and Taxes**
**For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Energy (Project 18)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $150,000 | $150,000 | $3,858,000 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,058,000 | 0 | 1,800,000 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | (1,600,000) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $1,600,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,058,000 | 2,058,000 | 3,858,000 | |
| 3 | Less: Accumulated Depreciation (A) | | (7,204) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (4,236) | (8,472) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 355,800 | 711,600 | 1,067,400 | 1,423,200 | 1,779,000 | 2,134,800 | 2,490,600 | 2,846,400 | 3,202,200 | 1,500,000 | 1,650,000 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $1,592,796 | $355,800 | $711,600 | $1,067,400 | $1,423,200 | $1,779,000 | $2,134,800 | $2,490,600 | $2,846,400 | $3,202,200 | $3,558,000 | $3,703,764 | $3,849,528 | |
| 6 | Average Net Investment | | | $974,298 | $533,700 | $889,500 | $1,245,300 | $1,601,100 | $1,956,900 | $2,312,700 | $2,668,500 | $3,024,300 | $3,380,100 | $3,630,882 | $3,776,646 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 1,645 | 901 | 1,502 | 2,103 | 2,703 | 3,304 | 3,905 | 4,506 | 5,107 | 5,707 | 6,131 | 6,377 | 43,891 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 6,767 | 3,707 | 6,178 | 8,650 | 11,121 | 13,592 | 16,063 | 18,535 | 21,006 | 23,477 | 25,219 | 26,232 | 180,547 |
| | c. Other (A) | | | (56,879) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (56,879) |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.4700% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4,236 | 4,236 | 8,472 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | 292 | 292 | 584 |
| | e. Other (A) | | | (7,700) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (7,700) |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | ($56,167) | $4,608 | $7,680 | $10,753 | $13,824 | $16,896 | $19,968 | $23,041 | $26,113 | $29,184 | $35,878 | $37,137 | 168,915 | |
| | a. Recoverable Costs Allocated to Energy | | (56,167) | 4,608 | 7,680 | 10,753 | 13,824 | 16,896 | 19,968 | 23,041 | 26,113 | 29,184 | 35,878 | 37,137 | 168,915 | |
| | b. Recoverable Costs Allocated to Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | | |
| 11 | Demand Jurisdictional Factor | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | ($54,946) | $4,499 | $7,551 | $10,516 | $13,437 | $16,399 | $19,321 | $22,235 | $25,239 | $28,221 | $34,682 | $36,273 | $163,427 | |
| 13 | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | ($54,946) | $4,499 | $7,551 | $10,516 | $13,437 | $16,399 | $19,321 | $22,235 | $25,239 | $28,221 | $34,682 | $36,273 | $163,427 | |

Notes:

(A) As explained in the testimony of Garry Miller, DEF has revised the permanent dust mitigation in-service date from October 2015 to October 2016 and determined vegetation management compliance can be achived without the 2015 capital investment. As a result, DEF has made these adjustments to ensure that the revenue requirement impact to customers is neutral.
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2nd Qtr end 2015, a total of 260 substation remediations are completed out of 279 slated for clean-up. DEF expects to remediate 3 more substations during the remainder of 2015.

**Project Fiscal Expenditures:**
2015 expenditures are estimated to be $405k lower than originally projected due to remediation work delays at the Consolidated Rock, Holder and Kenneth City substations.

**Project Progress Summary:**
DEF continues to remediate substation sites in accordance with the approved Substation Assessment and Remedial Action Plan (SARAP).

**Project Projections:**
2016 estimated expenditures are $1.1M.

**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:**
As of 2nd Qtr end 2015, there are 3 remaining Transformer Replacement and Inspection Program (TRIP) sites.

**Project Fiscal Expenditures:**
2015 expenditures are estimated to be $42k higher than originally projected due to costs to remove additional impacted soil at the three remaining sites.

**Project Progress Summary:**
This project is on schedule according to the approved Distribution System Investigation, Remediation and Pollution Prevention Program.

**Project Projections:**
2016 estimated expenditures are $3k.

**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) contains 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.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $19k higher than originally projected due to increased costs to comply with PIM regulations. No capital expenditures are estimated for 2015.

**Project Progress Summary:**
Ongoing regulatory compliance activities will continue until pipeline is sold or retired.

**Project Projections:**
2016 estimated O&M expenditures are $696k. No capital expenditures are expected in 2016.

**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 2015.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

**Project Projections:**
No project expenditures are expected in 2016.

**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 is treating its unused NOx costs as a regulatory asset amortizing it over 3 years, as approved by the Commission in Order No. PSC-11-0553-FOF-EI.

**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:**
2015 emission allowance expenditures are estimated to be $1.5M higher than originally projected due to unusable NOx emission allowances as a result of the expiration of the CAIR. CAIR was replaced by the CSAPR on 1/1/15. Consistent with Order No. PSC-11-0553-FOF-EI, DEF is treating costs associated with its unusable CAIR NOx emission allowances as a regulatory asset amortizing it over 3 years, beginning 1/1/15 until fully recovered by 12/31/17, with a return on the unamortized investment.

**Project Progress Summary:**
DEF continually evaluates the status of emission rules to maximize the cost effectiveness of its compliance strategy.

**Project Projections:**
2016 estimated expenditures are $111k. 2016 amortization of the CAIR NOx regulatory asset is approximately $3.6M.

**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.

**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 are under development to ensure compliance with all applicable requirements of the rule.

**Project Fiscal Expenditures:**
2015 project expenditures are estimated to be $43k lower than originally projected as methods used to allocate costs to analyze 316(b) compliance strategies at each affected Duke Energy station were adjusted to reflect present configurations and operations. DEF intends to implement a consistent approach across its entire fleet of regulated units to focus on full compliance with applicable 316(b) requirements through the development of facility specific strategic plans.

**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.

**Project Projections:**
2016 estimated O&M expenditures are $440k. No capital expenditures are expected in 2016.

**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 not 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)

**Project Accomplishments:**
The reclaimed water reuse system project was placed in-service in July 2015. This project will provide DEF with up to 1 1/2 million gallons per day of reclaimed water from the City of Crystal River to supplement well water use. This project has positive environmental impacts as it reduces aquifer use.

**Project Fiscal Expenditures:**
2015 estimated O&M expenditures are estimated to be $661k higher than originally projected due to a $710 decrease in CAIR Crystal River Project 7.4 - Base costs and $1.4 million increase in CAIR Crystal River Project 7.4 - Energy costs. The $710k is due to lower base routine project costs. The $1.4M is due to higher ammonia and hydrated lime costs offset by lower limestone and gypsum costs. 2015 estimated capital expenditures are expected to be $124k higher than originally projected due to a shift in spending from 2014 to 2015 in order to align with the City of Crystal River reclaimed water reuse project timeline.

**Project Progress Summary:**
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program.

**Project Projections:**
2016 estimated O&M and capital expenditures are $34.4M and $713k, 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 2015.

**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 2016.

**Project Title:** **Arsenic Groundwater Standard**
**Project No. 8**

**Project Description:**
On 1/22/01, the EPA adopted a new maximum contaminant level (MCL) for arsenic in drinking water replacing the previous standard of 0.050 mg/L (50ppb) with a new MCL of 0.010 mg/L (10ppb). 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 implications for land application and water reuse projects in Florida because the drinking water standard has been established as the groundwater standard by Rule 62-520.420(1), F.A.C. Lowering the arsenic standard will require new analytical methods for sampling groundwater at numerous DEF sites.

**Project Accomplishments:**
DEF has completed required monitoring as directed by the FDEP.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $23k higher than originally projected due to consultant costs to evaluate the source of arsenic exceedances and issue a summery report in compliance with FDEP Consent Order No. 09-3463C executed on 11/21/11. The Consent Order was issued by the FDEP for exceedance of the arsenic groundwater limit when the EPA lowered the arsenic maximum containment level from 50ppb to 10 ppb.

**Project Progress Summary:**
DEF is evaluating monitoring data and other options to achieve compliance in accordance to Consent Order.

**Project Projections:**
No project expenditures are expected in 2016.

**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:**
2015 capital expenditures are estimated to be $3k lower than originally projected. No new street lighting has been required in Franklin County, the City of Mexico Beach in Bay county or GULF County as DEF is in compliance with sea turtle ordinances. Also, the Don Cesar lighting project is delayed from 2014 to late 4th quarter 2015 due to scheduling conflicts.

**Project Progress Summary:**
DEF is on schedule with activities identified for this program.

**Project Projections:**
2016 estimated project O&M and capital expenditures are $450 and $750, 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

**Project Projections:**
No 2016 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 2015 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 2016 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. 060162-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 2015 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 180MWe 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 2016 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 2015 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 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
The mercury TMDL study concluded in 2012.

**Project Projections:**
No 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA during 2010.

**Project Projections:**
No 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA in September 2010.

**Project Projections:**
No 2016 expenditures are expected for this project.

**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 1/14/11, 2/14/11, 7/18/11,4/7/14 and 11/28/11, respectively. All facilities are required to meet new permitting conditions. In Docket No. 110007-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 thermal studies and whole effluent toxicity testing as required 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.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $54k lower than originally projected due to lower than expected 316(a) thermal study costs at the Anclote and Bartow stations. 2015 capital expenditures are expected to be $86k lower than originally projected due to a vendor reimbursement payment.

**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. DEF continues to work with FDEP to resolve the copper issue at the Suwannee station.

**Project Projections:**
2016 estimated O&M expenditures are $60k. No capital expenditures are expected in 2016.

**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-11-0553-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 the existing FGD and SCR systems as the primary MATS compliance measures. Additional monitoring and emissions reduction technologies will be installed in 2014 & 2015.

**Project Accomplishments:**
DEF installed ORP probes and particulate matter continuous emissions monitoring systems (PM CEMS) in 2014. In addition, a mercury characterization study was performed in late 2014, and temporary mercury re-emission control systems were installed in early 2015. DEF continues to monitor mercury emissions with Appendix K sorbent trap systems.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $153k higher than originally projected due to the addition of a temporary chemical injection system to control mercury emissions, and the cancellation of preliminary engineering for a fuel additive system to improve mercury oxidation. 2015 capital expenditures are expected to be $1.3M higher than originally projected driven by the installation of continuous emission monitoring systems (CEMS) for mercury monitoring, compliance demonstration and feedback to the re-emission control system.

**Project Progress Summary:**
Installation of mercury CEMS and permanent mercury re-emission control systems is scheduled in the third quarter of 2015. Certification and commissioning activities are expected to be completed by the end of the year.

**Project Projections:**
2016 estimated O&M is $529k. No capital expenditures are expected in 2016.

**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-12-0432-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:**
2015 capital expenditures are estimated to be $314k lower than originally projected due to earlier than expected completion of Unit 2 FD fan work in November 2013 versus December 2014. There are no recoverable O&M costs for this project.

**Project Progress Summary:**
This project is in-service.

**Project Projections:**
No 2016 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-14-0173-PAA-EI. DEF will make modifications to the electrostatic precipitators to improve particulate collection efficiency, as well as install reagent injection systems to reduce HCl and mercury emissions.

**Project Accomplishments:**
DEF finalized its CR1&2 MATS Compliance Plan in December 2013 and began implementation in early 2014.

**Project Fiscal Expenditures:**
2015 O&M expenditures are expected to be $51k lower than expected. Capital expenditures are estimated to be $4.2M higher than originally projected due to an additional project related to the Unit 1 electrostatic precipitator (ESP).

**Project Progress Summary:**
Implementation of the CR1&2 MATS Compliance Plan will be completed by April 2016.

**Project Projections:**
2016 estimated O&M and capital expenditures are $3.8M and $2.6M, respectively.

**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:**
DEF began defining and implementing of its CCR Rule compliance strategy.

**Project Fiscal Expenditures:**
2015 estimated O&M and capital expenditures are $391k and $1.6M, respectively.

**Project Progress Summary:**
Ash Landfill: Two engineering firms are studying Crystal River ash landfill stability and ash placement.
Temporary Gypsum Pad: Efforts are underway to address fugitive dust mitigation at the CCR gypsum stack-out.
FGD Blowdown Ponds: A definitive assessment and action plan is being developed.
Emergency Action Plan: A determination if the CCR requires an EPA for the FGD Blowdown Ponds is in process.
Vegetation Mgt & Inspection Work: More frequent mowing and inspection work is planned to comply with the CCR Rule.

**Project Projections:**
2016 estimated O&M and capital expenditures are $1.8M and $3.9M, respectively. See the August 31, 2015 direct testimony of Mr. Miller for 2015 CCR compliance strategy change.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of the Energy & Demand Allocation % by Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) Average 12CP Load Factor at Meter (%) | (2) Sales at Meter (mWh) | (3) Avg 12 CP at Meter (MW) (2)/(8784hrsx(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)/(8784hrs/(4)) | (9) mWh Sales at Source Energy Allocator (%) | (10) 12CP Demand Transmission Allocator (%) | (11) 12CP & 1/13 AD Demand Allocator (%) | (12) NCP Distribution Allocator (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | | | | | |
| **RS-1, RST-1, RSL-1, RSL-2, RSS-1** | | | | | | | | | | | | | |
| Secondary | 0.518 | 19,482,925 | 4,282.48 | 0.401 | 0.9463589 | 20,587,248 | 4,525.22 | 20,587,248 | 5,851.4 | 51.568% | 61.617% | 60.844% | 61.780% |
| **General Service Non-Demand** | | | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | | | |
| Secondary | 0.682 | 1,547,422 | 258.45 | 0.491 | 0.9463589 | 1,635,132 | 273.10 | 1,635,132 | 378.9 | 4.096% | 3.719% | 3.748% | 4.000% |
| Primary | 0.682 | 8,546 | 1.43 | 0.491 | 0.9766343 | 8,750 | 1.46 | 8,750 | 2.0 | 0.022% | 0.020% | 0.020% | 0.021% |
| Transmission | 0.682 | 3,571 | 0.60 | 0.491 | 0.9866343 | 3,619 | 0.60 | 0 | 0.0 | 0.009% | 0.008% | 0.008% | 0.000% |
| | | | | | | | | | | 4.127% | 3.747% | 3.776% | 4.021% |
| **General Service** | | | | | | | | | | | | | |
| **GS-2** Secondary | 1.000 | 161,981 | 18.44 | 1.000 | 0.9463589 | 171,162 | 19.49 | 171,162 | 19.5 | 0.429% | 0.265% | 0.278% | 0.206% |
| **General Service Demand** | | | | | | | | | | | | | |
| **GSD-1, GSDT-1** | | | | | | | | | | | | | |
| Secondary | 0.749 | 11,824,122 | 1,797.93 | 0.594 | 0.9463589 | 12,494,332 | 1,899.84 | 12,494,332 | 2,394.0 | 31.296% | 25.869% | 26.286% | 25.277% |
| Primary | 0.749 | 2,313,813 | 351.83 | 0.594 | 0.9766343 | 2,369,170 | 360.25 | 2,369,170 | 454.0 | 5.934% | 4.905% | 4.984% | 4.793% |
| Secondary Del/ Primary Mtr | 0.749 | 46,245 | 7.03 | 0.594 | 0.9766343 | 47,351 | 7.20 | 47,351 | 9.1 | 0.119% | 0.098% | 0.100% | 0.096% |
| Transm Del/ Primary Mtr | 0.749 | 1,419 | 0.22 | 0.594 | 0.9766343 | 1,453 | 0.22 | 0 | 0.0 | 0.004% | 0.003% | 0.003% | 0.000% |
| Transmission | 0.749 | 0 | 0.00 | 0.594 | 0.9866343 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| **SS-1** Primary | 1.166 | 5,602 | 0.55 | 0.093 | 0.9766343 | 5,736 | 0.56 | 5,736 | 7.0 | 0.014% | 0.008% | 0.008% | 0.074% |
| Transm Del/ Transm Mtr | 1.166 | 11,127 | 1.09 | 0.093 | 0.9866343 | 11,278 | 1.10 | 0 | 0.0 | 0.028% | 0.015% | 0.016% | 0.000% |
| Transm Del/ Primary Mtr | 1.166 | 3,474 | 0.34 | 0.093 | 0.9766343 | 3,557 | 0.35 | 0 | 0.0 | 0.009% | 0.005% | 0.005% | 0.000% |
| | | | | | | | | | | 37.404% | 30.902% | 31.403% | 30.240% |
| **Curtailable** | | | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, SS-3** | | | | | | | | | | | | | |
| Secondary | 1.305 | 0 | 0.00 | 0.456 | 0.9463589 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| Primary | 1.305 | 121,852 | 10.63 | 0.456 | 0.9766343 | 124,767 | 10.88 | 124,767 | 31.2 | 0.313% | 0.148% | 0.161% | 0.329% |
| **SS-3** Primary | 0.583 | 3,604 | 0.70 | 0.077 | 0.9766343 | 3,690 | 0.72 | 3,690 | 5.5 | 0.009% | 0.010% | 0.010% | 0.058% |
| | | | | | | | | | | 0.322% | 0.158% | 0.171% | 0.387% |
| **Interruptible** | | | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2** | | | | | | | | | | | | | |
| Secondary | 1.009 | 88,539 | 9.99 | 0.707 | 0.9463589 | 93,558 | 10.55 | 93,558 | 15.1 | 0.234% | 0.144% | 0.151% | 0.159% |
| Sec Del/Primary Mtr | 1.009 | 4,449 | 0.50 | 0.707 | 0.9766343 | 4,555 | 0.51 | 4,555 | 0.7 | 0.011% | 0.007% | 0.007% | 0.008% |
| Primary Del / Primary Mtr | 1.009 | 1,229,525 | 138.66 | 0.707 | 0.9766343 | 1,258,941 | 141.98 | 1,258,941 | 202.9 | 3.153% | 1.933% | 2.027% | 2.142% |
| Primary Del / Transm Mtr | 1.009 | 9,117 | 1.03 | 0.707 | 0.9866343 | 9,241 | 1.04 | 9,241 | 1.5 | 0.023% | 0.014% | 0.015% | 0.016% |
| Transm Del/ Transm Mtr | 1.009 | 222,224 | 25.06 | 0.707 | 0.9866343 | 225,234 | 25.40 | 0 | 0.0 | 0.564% | 0.346% | 0.363% | 0.000% |
| Transm Del/ Primary Mtr | 1.009 | 269,448 | 30.39 | 0.707 | 0.9766343 | 275,894 | 31.11 | 0 | 0.0 | 0.691% | 0.424% | 0.444% | 0.000% |
| **SS-2** Primary | 0.870 | 9,262 | 1.21 | 0.380 | 0.9766343 | 9,484 | 1.24 | 9,484 | 2.8 | 0.024% | 0.017% | 0.017% | 0.030% |
| Transm Del/ Transm Mtr | 0.870 | 92,038 | 12.05 | 0.380 | 0.9866343 | 93,285 | 12.21 | 0 | 0.0 | 0.234% | 0.166% | 0.171% | 0.000% |
| Transm Del/ Primary Mtr | 0.870 | 80,335 | 10.52 | 0.380 | 0.9766343 | 82,257 | 10.77 | 0 | 0.0 | 0.206% | 0.147% | 0.151% | 0.000% |
| | | | | | | | | | | 5.141% | 3.197% | 3.347% | 2.354% |
| **Lighting** | | | | | | | | | | | | | |
| **LS-1** (Secondary) | 5.506 | 381,551 | 7.89 | 0.479 | 0.9463589 | 403,178 | 8.34 | 403,178 | 95.8 | 1.010% | 0.114% | 0.182% | 1.012% |
| | | 37,922,191 | 6,969.01 | | | 39,922,874 | 7,344.16 | 39,226,296 | 9,471.2 | 100.000% | 100.000% | 100.000% | 100.000% |

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2015
(2) Projected kWh sales for the period January 2016 to December 2016
(3) Calculated: Column 2 / (8,784 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2015
(5) Based on system average line loss analysis for 2014
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,784 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 9 x 1/13 + Column 10 x 12/13
(12) Column 8/ Total Column 8

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) mWh Sales at Source Energy Allocator (%) | (2) 12CP Transmission Demand Allocator (%) | (3) 12CP & 1/13th AD Demand Allocator (%) | (4) NCP Distribution Allocator (%) | (5) Energy-Related Costs ($) | (6) Transmission Demand Costs ($) | (8) Production Demand Costs ($) | (7) Distribution Demand Costs ($) | (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 | 51.568% | 61.617% | 60.844% | 61.780% | $33,378,628 | $480,062 | $2,168,692 | ($164,617) | $35,862,765 | 19,482,925 | **0.184** |
| **General Service Non-Demand** | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 1,547,422 | **0.181** |
| Primary | | | | | | | | | | 8,461 | **0.179** |
| Transmission | | | | | | | | | | 3,500 | **0.177** |
| **TOTAL GS** | 4.127% | 3.747% | 3.776% | 4.021% | $2,671,137 | $29,191 | $134,590 | ($10,715) | $2,824,203 | **1,559,382** | |
| **General Service** | | | | | | | | | | | |
| **GS-2** Secondary | 0.429% | 0.265% | 0.278% | 0.206% | $277,510 | $2,067 | $9,905.12 | ($548.19) | $288,934 | 161,981 | **0.178** |
| **General Service Demand** | | | | | | | | | | | |
| **GSD-1, GSDT-1, SS-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 11,824,122 | **0.180** |
| Primary | | | | | | | | | | 2,346,847 | **0.178** |
| Transmission | | | | | | | | | | 10,904 | **0.176** |
| **TOTAL GSD** | 37.404% | 30.902% | 31.403% | 30.240% | $24,211,054 | $240,764 | $1,119,303 | ($80,575) | $25,490,546 | **14,181,874** | |
| **Curtailable** | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3** | | | | | | | | | | | |
| Secondary | | | | | | | | | | - | **0.173** |
| Primary | | | | | | | | | | 124,201 | **0.171** |
| Transmission | | | | | | | | | | - | **0.170** |
| **TOTAL CS** | 0.322% | 0.158% | 0.171% | 0.387% | $208,271 | $1,231 | $6,081 | ($1,030) | $214,553 | **124,201** | |
| **Interruptible** | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2, SS-2** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 88,539 | **0.175** |
| Primary | | | | | | | | | | 1,577,089 | **0.173** |
| Transmission | | | | | | | | | | 316,911 | **0.172** |
| **TOTAL IS** | 5.141% | 3.197% | 3.347% | 2.354% | $3,327,687 | $24,912 | $119,299 | ($6,274) | $3,465,624 | **1,982,539** | |
| **Lighting** | | | | | | | | | | | |
| **LS-1** Secondary | 1.010% | 0.114% | 0.182% | 1.012% | $653,683 | $884 | $6,503.57 | ($2,695.78) | $658,375 | 381,551 | **0.173** |
| | 100.000% | 100.000% | 100.000% | 100.000% | $64,727,970 | $779,111 | $3,564,373 | ($266,454) | $68,805,000 | 37,874,454 | **0.182** |

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 4 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
(8) Column 3 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 2016 to December 2016
(11) (Column 9/ Column 10)/10

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Capital Structure and Cost Rates**



| Class of Capital | | Retail Amount | Ratio | Cost Rate | Weighted Cost Rate | PreTax Weighted Cost Rate |
|---|---|---|---|---|---|---|
| CE | $ | 4,681,853 | 48.76% | 0.10500 | 5.120% | 8.335% |
| PS | | - | 0.00% | 0.00000 | 0.000% | 0.000% |
| LTD | | 3,672,596 | 38.25% | 0.05187 | 1.984% | 1.984% |
| STD | | (90,568) | -0.94% | 0.00170 | -0.002% | -0.002% |
| CD-Active | | 182,163 | 1.90% | 0.02306 | 0.044% | 0.044% |
| CD-Inactive | | 1,306 | 0.01% | 0.00000 | 0.000% | 0.000% |
| ADIT | | 1,318,615 | 13.73% | 0.00000 | 0.000% | 0.000% |
| FAS 109 | | (164,391) | -1.71% | 0.00000 | 0.000% | 0.000% |
| ITC | | 498 | 0.01% | 0.00000 | 0.000% | 0.000% |
| Total | $ | 9,602,073 | 100.00% | | 7.146% | 10.361% |
| | | | | Total Debt | 2.026% | 2.026% |
| | | | | Total Equity | 5.120% | 8.335% |

May 2015 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 2016 - December 2016**

**Docket No. 150007-EI**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 15
PARTY: DUKE ENERGY FLORIDA, LLC
(DEF) – (DIRECT)
DESCRIPTION: Thomas G. Foster TGF-6

**For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)**
**(in Dollars)**

NERGY FLORIDA, LLC

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | 33,952 | 33,952 | 33,952 | 33,952 | 33,952 | 33,952 | 33,952 | |
| 3 | Less: Accumulated Depreciation | | | (9,337) | (9,390) | (9,443) | (9,496) | (9,549) | (9,602) | (9,655) | (9,708) | (9,761) | (9,814) | (9,867) | (9,920) | (9,973) | |
| 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) | | | $24,616 | $24,563 | $24,510 | $24,457 | $24,404 | $24,351 | $24,298 | $24,245 | $24,192 | $24,139 | $24,086 | $24,033 | $23,980 | |
| 6 | Average Net Investment | | | | 24,589 | 24,536 | 24,483 | 24,430 | 24,377 | 24,324 | 24,271 | 24,218 | 24,165 | 24,112 | 24,059 | 24,006 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 42 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 493 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 171 | 170 | 170 | 170 | 169 | 169 | 169 | 168 | 168 | 167 | 167 | 167 | 2,025 |
| | 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 | 53 | 53 | 53 | 53 | 53 | 53 | 636 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.009672 | | | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 324 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $293 | $291 | $291 | $291 | $290 | $290 | $290 | $289 | $289 | $288 | $288 | $288 | $3,478 |
| | 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 | | | | $293 | $291 | $291 | $291 | $290 | $290 | $290 | $289 | $289 | $288 | $288 | $288 | $3,478 |

**For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | $1,536,272 | |
| 3 | Less: Accumulated Depreciation | | | (571,437) | (574,712) | (577,987) | (581,262) | (584,537) | (587,812) | (591,087) | (594,362) | (597,637) | (600,912) | (604,187) | (607,462) | (610,737) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $964,835 | $961,560 | $958,285 | $955,010 | $951,735 | $948,460 | $945,185 | $941,910 | $938,635 | $935,360 | $932,085 | $928,810 | $925,535 | |
| 6 | Average Net Investment | | | | 963,198 | 959,923 | 956,648 | 953,373 | 950,098 | 946,823 | 943,548 | 940,273 | 936,998 | 933,723 | 930,448 | 927,173 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 1,626 | 1,621 | 1,615 | 1,610 | 1,604 | 1,599 | 1,593 | 1,588 | 1,582 | 1,577 | 1,571 | 1,566 | 19,152 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 6,690 | 6,667 | 6,645 | 6,622 | 6,599 | 6,576 | 6,554 | 6,531 | 6,508 | 6,485 | 6,463 | 6,440 | 78,780 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 2.5579% | | | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 3,275 | 39,300 |
| | 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 | 0.009672 | | | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 1,238 | 14,856 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $12,829 | $12,801 | $12,773 | $12,745 | $12,716 | $12,688 | $12,660 | $12,632 | $12,603 | $12,575 | $12,547 | $12,519 | $152,088 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $12,829 | $12,801 | $12,773 | $12,745 | $12,716 | $12,688 | $12,660 | $12,632 | $12,603 | $12,575 | $12,547 | $12,519 | $152,088 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | 909,407 | |
| 3 | Less: Accumulated Depreciation | | | (178,396) | (180,334) | (182,272) | (184,210) | (186,148) | (188,086) | (190,024) | (191,962) | (193,900) | (195,838) | (197,776) | (199,714) | (201,652) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $731,011 | $729,073 | $727,135 | $725,197 | $723,259 | $721,321 | $719,383 | $717,445 | $715,507 | $713,569 | $711,631 | $709,693 | $707,755 | |
| 6 | Average Net Investment | | | | 730,042 | 728,104 | 726,166 | 724,228 | 722,290 | 720,352 | 718,414 | 716,476 | 714,538 | 712,600 | 710,662 | 708,724 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 1,233 | 1,229 | 1,226 | 1,223 | 1,220 | 1,216 | 1,213 | 1,210 | 1,206 | 1,203 | 1,200 | 1,197 | 14,576 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 5,071 | 5,057 | 5,044 | 5,030 | 5,017 | 5,003 | 4,990 | 4,976 | 4,963 | 4,950 | 4,936 | 4,923 | 59,960 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 2.5579% | | | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 1,938 | 23,256 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.009672 | | | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 8,796 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $8,975 | $8,957 | $8,941 | $8,924 | $8,908 | $8,890 | $8,874 | $8,857 | $8,840 | $8,824 | $8,807 | $8,791 | $106,588 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $8,975 | $8,957 | $8,941 | $8,924 | $8,908 | $8,890 | $8,874 | $8,857 | $8,840 | $8,824 | $8,807 | $8,791 | $106,588 |

**For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | |
| 3 | Less: Accumulated Depreciation | | | (18,336) | (18,714) | (19,092) | (19,470) | (19,848) | (20,226) | (20,604) | (20,982) | (21,360) | (21,738) | (22,116) | (22,494) | (22,872) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $116,738 | $116,360 | $115,982 | $115,604 | $115,226 | $114,848 | $114,470 | $114,092 | $113,714 | $113,336 | $112,958 | $112,580 | $112,202 | |
| 6 | Average Net Investment | | | | 116,549 | 116,171 | 115,793 | 115,415 | 115,037 | 114,659 | 114,281 | 113,903 | 113,525 | 113,147 | 112,769 | 112,391 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 197 | 196 | 196 | 195 | 194 | 194 | 193 | 192 | 192 | 191 | 190 | 190 | 2,320 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 810 | 807 | 804 | 802 | 799 | 796 | 794 | 791 | 789 | 786 | 783 | 781 | 9,542 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 3.3596% | | | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 378 | 4,536 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.009672 | | | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 1,308 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,494 | $1,490 | $1,487 | $1,484 | $1,480 | $1,477 | $1,474 | $1,470 | $1,468 | $1,464 | $1,460 | $1,458 | $17,706 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,494 | $1,490 | $1,487 | $1,484 | $1,480 | $1,477 | $1,474 | $1,470 | $1,468 | $1,464 | $1,460 | $1,458 | $17,706 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)**
**(in Dollars)**

DUKE ENERGY FLORIDA, LLC

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | 2,066,600 | |
| 3 | Less: Accumulated Depreciation | | | (405,663) | (410,821) | (415,979) | (421,137) | (426,295) | (431,453) | (436,611) | (441,769) | (446,927) | (452,085) | (457,243) | (462,401) | (467,559) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $1,660,937 | $1,655,779 | $1,650,621 | $1,645,463 | $1,640,305 | $1,635,147 | $1,629,989 | $1,624,831 | $1,619,673 | $1,614,515 | $1,609,357 | $1,604,199 | $1,599,041 | |
| 6 | Average Net Investment | | | | 1,658,358 | 1,653,200 | 1,648,042 | 1,642,884 | 1,637,726 | 1,632,568 | 1,627,410 | 1,622,252 | 1,617,094 | 1,611,936 | 1,606,778 | 1,601,620 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 2,800 | 2,791 | 2,783 | 2,774 | 2,765 | 2,757 | 2,748 | 2,739 | 2,730 | 2,722 | 2,713 | 2,704 | 33,026 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 11,519 | 11,483 | 11,447 | 11,411 | 11,375 | 11,339 | 11,304 | 11,268 | 11,232 | 11,196 | 11,160 | 11,124 | 135,858 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | Blended | | | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 5,158 | 61,896 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.011680 | | | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 24,132 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $21,488 | $21,443 | $21,399 | $21,354 | $21,309 | $21,265 | $21,221 | $21,176 | $21,131 | $21,087 | $21,042 | $20,997 | $254,912 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $21,488 | $21,443 | $21,399 | $21,354 | $21,309 | $21,265 | $21,221 | $21,176 | $21,131 | $21,087 | $21,042 | $20,997 | $254,912 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (292,551) | (296,236) | (299,921) | (303,606) | (307,291) | (310,976) | (314,661) | (318,346) | (322,031) | (325,716) | (329,401) | (333,086) | (336,771) | |
| 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) | | | $1,181,250 | $1,177,565 | $1,173,880 | $1,170,195 | $1,166,510 | $1,162,825 | $1,159,140 | $1,155,455 | $1,151,770 | $1,148,085 | $1,144,400 | $1,140,715 | $1,137,030 | |
| 6 | Average Net Investment | | | | 1,179,407 | 1,175,722 | 1,172,037 | 1,168,352 | 1,164,667 | 1,160,982 | 1,157,297 | 1,153,612 | 1,149,927 | 1,146,242 | 1,142,557 | 1,138,872 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 1,991 | 1,985 | 1,979 | 1,973 | 1,967 | 1,960 | 1,954 | 1,948 | 1,942 | 1,935 | 1,929 | 1,923 | 23,486 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 8,192 | 8,166 | 8,141 | 8,115 | 8,089 | 8,064 | 8,038 | 8,013 | 7,987 | 7,961 | 7,936 | 7,910 | 96,612 |
| | 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 | 0.009890 | | | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 | 14,580 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $15,083 | $15,051 | $15,020 | $14,988 | $14,956 | $14,924 | $14,892 | $14,861 | $14,829 | $14,796 | $14,765 | $14,733 | $178,898 |
| | 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 | | | | $15,083 | $15,051 | $15,020 | $14,988 | $14,956 | $14,924 | $14,892 | $14,861 | $14,829 | $14,796 | $14,765 | $14,733 | $178,898 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (834,131) | (843,270) | (852,409) | (861,548) | (870,687) | (879,826) | (888,965) | (898,104) | (907,243) | (916,382) | (925,521) | (934,660) | (943,799) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $827,533 | $818,394 | $809,255 | $800,116 | $790,977 | $781,838 | $772,699 | $763,560 | $754,421 | $745,282 | $736,143 | $727,004 | $717,865 | |
| 6 | Average Net Investment | | | | 822,964 | 813,825 | 804,686 | 795,547 | 786,408 | 777,269 | 768,130 | 758,991 | 749,852 | 740,713 | 731,574 | 722,435 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 1,390 | 1,374 | 1,359 | 1,343 | 1,328 | 1,312 | 1,297 | 1,282 | 1,266 | 1,251 | 1,235 | 1,220 | 15,657 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 5,716 | 5,653 | 5,589 | 5,526 | 5,462 | 5,399 | 5,335 | 5,272 | 5,208 | 5,145 | 5,081 | 5,018 | 64,404 |
| | 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 | 0.008700 | | | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 1,205 | 14,460 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $17,450 | $17,371 | $17,292 | $17,213 | $17,134 | $17,055 | $16,976 | $16,898 | $16,818 | $16,740 | $16,660 | $16,582 | $204,189 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $17,450 | $17,371 | $17,292 | $17,213 | $17,134 | $17,055 | $16,976 | $16,898 | $16,818 | $16,740 | $16,660 | $16,582 | $204,189 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (72,713) | (73,429) | (74,145) | (74,861) | (75,577) | (76,293) | (77,009) | (77,725) | (78,441) | (79,157) | (79,873) | (80,589) | (81,305) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $106,225 | $105,509 | $104,793 | $104,077 | $103,361 | $102,645 | $101,929 | $101,213 | $100,497 | $99,781 | $99,065 | $98,349 | $97,633 | |
| 6 | Average Net Investment | | | | 105,867 | 105,151 | 104,435 | 103,719 | 103,003 | 102,287 | 101,571 | 100,855 | 100,139 | 99,423 | 98,707 | 97,991 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 179 | 178 | 176 | 175 | 174 | 173 | 172 | 170 | 169 | 168 | 167 | 165 | 2,066 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 735 | 730 | 725 | 720 | 715 | 710 | 705 | 701 | 696 | 691 | 686 | 681 | 8,495 |
| | 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 | 0.009380 | | | 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) | | | | $1,770 | $1,764 | $1,757 | $1,751 | $1,745 | $1,739 | $1,733 | $1,727 | $1,721 | $1,715 | $1,709 | $1,702 | $20,833 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,770 | $1,764 | $1,757 | $1,751 | $1,745 | $1,739 | $1,733 | $1,727 | $1,721 | $1,715 | $1,709 | $1,702 | $20,833 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (176,876) | (178,698) | (180,520) | (182,342) | (184,164) | (185,986) | (187,808) | (189,630) | (191,452) | (193,274) | (195,096) | (196,918) | (198,740) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $553,419 | $551,597 | $549,775 | $547,953 | $546,131 | $544,309 | $542,487 | $540,665 | $538,843 | $537,021 | $535,199 | $533,377 | $531,555 | |
| 6 | Average Net Investment | | | | 552,508 | 550,686 | 548,864 | 547,042 | 545,220 | 543,398 | 541,576 | 539,754 | 537,932 | 536,110 | 534,288 | 532,466 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 933 | 930 | 927 | 924 | 921 | 918 | 914 | 911 | 908 | 905 | 902 | 899 | 10,992 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 3,838 | 3,825 | 3,812 | 3,800 | 3,787 | 3,774 | 3,762 | 3,749 | 3,736 | 3,724 | 3,711 | 3,698 | 45,216 |
| | 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 | 0.009890 | | | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 602 | 7,224 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $7,195 | $7,179 | $7,163 | $7,148 | $7,132 | $7,116 | $7,100 | $7,084 | $7,068 | $7,053 | $7,037 | $7,021 | $85,296 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $7,195 | $7,179 | $7,163 | $7,148 | $7,132 | $7,116 | $7,100 | $7,084 | $7,068 | $7,053 | $7,037 | $7,021 | $85,296 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (289,704) | (292,556) | (295,408) | (298,260) | (301,112) | (303,964) | (306,816) | (309,668) | (312,520) | (315,372) | (318,224) | (321,076) | (323,928) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $747,495 | $744,643 | $741,791 | $738,939 | $736,087 | $733,235 | $730,383 | $727,531 | $724,679 | $721,827 | $718,975 | $716,123 | $713,271 | |
| 6 | Average Net Investment | | | | 746,069 | 743,217 | 740,365 | 737,513 | 734,661 | 731,809 | 728,957 | 726,105 | 723,253 | 720,401 | 717,549 | 714,697 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 1,260 | 1,255 | 1,250 | 1,245 | 1,240 | 1,236 | 1,231 | 1,226 | 1,221 | 1,216 | 1,212 | 1,207 | 14,799 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 5,182 | 5,162 | 5,142 | 5,123 | 5,103 | 5,083 | 5,063 | 5,043 | 5,024 | 5,004 | 4,984 | 4,964 | 60,877 |
| | 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 | 0.008630 | | | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 8,952 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $10,040 | $10,015 | $9,990 | $9,966 | $9,941 | $9,917 | $9,892 | $9,867 | $9,843 | $9,818 | $9,794 | $9,769 | $118,852 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $10,040 | $10,015 | $9,990 | $9,966 | $9,941 | $9,917 | $9,892 | $9,867 | $9,843 | $9,818 | $9,794 | $9,769 | $118,852 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (539,978) | (547,815) | (555,652) | (563,489) | (571,326) | (579,163) | (587,000) | (594,837) | (602,674) | (610,511) | (618,348) | (626,185) | (634,022) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $3,076,926 | $3,069,089 | $3,061,252 | $3,053,415 | $3,045,578 | $3,037,741 | $3,029,904 | $3,022,067 | $3,014,230 | $3,006,393 | $2,998,556 | $2,990,719 | $2,982,882 | |
| 6 | Average Net Investment | | | | 3,073,007 | 3,065,170 | 3,057,333 | 3,049,496 | 3,041,659 | 3,033,822 | 3,025,985 | 3,018,148 | 3,010,311 | 3,002,474 | 2,994,637 | 2,986,800 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 5,189 | 5,176 | 5,162 | 5,149 | 5,136 | 5,123 | 5,109 | 5,096 | 5,083 | 5,070 | 5,056 | 5,043 | 61,392 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 21,344 | 21,290 | 21,235 | 21,181 | 21,127 | 21,072 | 21,018 | 20,963 | 20,909 | 20,854 | 20,800 | 20,746 | 252,539 |
| | 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 | 0.011680 | | | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 3,520 | 42,240 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $37,890 | $37,823 | $37,754 | $37,687 | $37,620 | $37,552 | $37,484 | $37,416 | $37,349 | $37,281 | $37,213 | $37,146 | $450,215 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $37,890 | $37,823 | $37,754 | $37,687 | $37,620 | $37,552 | $37,484 | $37,416 | $37,349 | $37,281 | $37,213 | $37,146 | $450,215 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (54,558) | (54,799) | (55,040) | (55,281) | (55,522) | (55,763) | (56,004) | (56,245) | (56,486) | (56,727) | (56,968) | (57,209) | (57,450) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $86,876 | $86,635 | $86,394 | $86,153 | $85,912 | $85,671 | $85,430 | $85,189 | $84,948 | $84,707 | $84,466 | $84,225 | $83,984 | |
| 6 | Average Net Investment | | | | 86,756 | 86,515 | 86,274 | 86,033 | 85,792 | 85,551 | 85,310 | 85,069 | 84,828 | 84,587 | 84,346 | 84,105 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 146 | 146 | 146 | 145 | 145 | 144 | 144 | 144 | 143 | 143 | 142 | 142 | 1,730 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 603 | 601 | 599 | 598 | 596 | 594 | 593 | 591 | 589 | 588 | 586 | 584 | 7,122 |
| | 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 | 0.012880 | | | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 1,824 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,142 | $1,140 | $1,138 | $1,136 | $1,134 | $1,131 | $1,130 | $1,128 | $1,125 | $1,124 | $1,121 | $1,119 | $13,568 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,142 | $1,140 | $1,138 | $1,136 | $1,134 | $1,131 | $1,130 | $1,128 | $1,125 | $1,124 | $1,121 | $1,119 | $13,568 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (139,740) | (141,517) | (143,294) | (145,071) | (146,848) | (148,625) | (150,402) | (152,179) | (153,956) | (155,733) | (157,510) | (159,287) | (161,064) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $255,228 | $253,451 | $251,674 | $249,897 | $248,120 | $246,343 | $244,566 | $242,789 | $241,012 | $239,235 | $237,458 | $235,681 | $233,904 | |
| 6 | Average Net Investment | | | | 254,339 | 252,562 | 250,785 | 249,008 | 247,231 | 245,454 | 243,677 | 241,900 | 240,123 | 238,346 | 236,569 | 234,792 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 429 | 426 | 423 | 420 | 417 | 414 | 411 | 408 | 405 | 402 | 399 | 396 | 4,950 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 1,767 | 1,754 | 1,742 | 1,730 | 1,717 | 1,705 | 1,693 | 1,680 | 1,668 | 1,655 | 1,643 | 1,631 | 20,385 |
| | 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 | 0.009890 | | | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 3,912 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $4,299 | $4,283 | $4,268 | $4,253 | $4,237 | $4,222 | $4,207 | $4,191 | $4,176 | $4,160 | $4,145 | $4,130 | $50,571 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $4,299 | $4,283 | $4,268 | $4,253 | $4,237 | $4,222 | $4,207 | $4,191 | $4,176 | $4,160 | $4,145 | $4,130 | $50,571 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (15,891) | (15,993) | (16,095) | (16,197) | (16,299) | (16,401) | (16,503) | (16,605) | (16,707) | (16,809) | (16,911) | (17,013) | (17,115) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $17,201 | $17,099 | $16,997 | $16,895 | $16,793 | $16,691 | $16,589 | $16,487 | $16,385 | $16,283 | $16,181 | $16,079 | $15,977 | |
| 6 | Average Net Investment | | | | 17,150 | 17,048 | 16,946 | 16,844 | 16,742 | 16,640 | 16,538 | 16,436 | 16,334 | 16,232 | 16,130 | 16,028 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 29 | 29 | 29 | 28 | 28 | 28 | 28 | 28 | 28 | 27 | 27 | 27 | 336 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 119 | 118 | 118 | 117 | 116 | 116 | 115 | 114 | 113 | 113 | 112 | 111 | 1,382 |
| | 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 | 0.001703 | | | 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) | | | | $255 | $254 | $254 | $252 | $251 | $251 | $250 | $249 | $248 | $247 | $246 | $245 | $3,002 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $255 | $254 | $254 | $252 | $251 | $251 | $250 | $249 | $248 | $247 | $246 | $245 | $3,002 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | 115,892 | 112,962 | 110,032 | 107,102 | 104,172 | 101,242 | 98,312 | 95,382 | 92,452 | 89,522 | 86,592 | 83,662 | 80,732 | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $2,481,840 | $2,478,910 | $2,475,980 | $2,473,050 | $2,470,120 | $2,467,190 | $2,464,260 | $2,461,330 | $2,458,400 | $2,455,470 | $2,452,540 | $2,449,610 | $2,446,680 | |
| 6 | Average Net Investment | | | | 2,480,375 | 2,477,445 | 2,474,515 | 2,471,585 | 2,468,655 | 2,465,725 | 2,462,795 | 2,459,865 | 2,456,935 | 2,454,005 | 2,451,075 | 2,448,145 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 4,188 | 4,183 | 4,178 | 4,173 | 4,168 | 4,163 | 4,158 | 4,153 | 4,149 | 4,144 | 4,139 | 4,134 | 49,930 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 17,228 | 17,208 | 17,187 | 17,167 | 17,147 | 17,126 | 17,106 | 17,086 | 17,065 | 17,045 | 17,025 | 17,004 | 205,394 |
| | 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 | 0.001703 | | | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 4,032 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $24,682 | $24,657 | $24,631 | $24,606 | $24,581 | $24,555 | $24,530 | $24,505 | $24,480 | $24,455 | $24,430 | $24,404 | $294,516 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $24,682 | $24,657 | $24,631 | $24,606 | $24,581 | $24,555 | $24,530 | $24,505 | $24,480 | $24,455 | $24,430 | $24,404 | $294,516 |

**For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | ($60,186) | (60,711) | (61,236) | (61,761) | (62,286) | (62,811) | (63,336) | (63,861) | (64,386) | (64,911) | (65,436) | (65,961) | (66,486) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $230,112 | $229,587 | $229,062 | $228,537 | $228,012 | $227,487 | $226,962 | $226,437 | $225,912 | $225,387 | $224,862 | $224,337 | $223,812 | |
| 6 | Average Net Investment | | | | 229,849 | 229,324 | 228,799 | 228,274 | 227,749 | 227,224 | 226,699 | 226,174 | 225,649 | 225,124 | 224,599 | 224,074 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 388 | 387 | 386 | 385 | 385 | 384 | 383 | 382 | 381 | 380 | 379 | 378 | 4,598 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 1,596 | 1,593 | 1,589 | 1,586 | 1,582 | 1,578 | 1,575 | 1,571 | 1,567 | 1,564 | 1,560 | 1,556 | 18,917 |
| | 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 | 0.007910 | | | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 2,292 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**For Project: CAIR CTs - AVON PARK (Project 7.2a)**
**(in Dollars)**

:NERGY FLORIDA, LLC

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | (33,641) | (34,045) | (34,449) | (34,853) | (35,257) | (35,661) | (36,065) | (36,469) | (36,873) | (37,277) | (37,681) | (38,085) | (38,489) | |
| 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) | | $128,113 | $127,709 | $127,305 | $126,901 | $126,497 | $126,093 | $125,689 | $125,285 | $124,881 | $124,477 | $124,073 | $123,669 | $123,265 | |
| 6 | Average Net Investment | | | 127,911 | 127,507 | 127,103 | 126,699 | 126,295 | 125,891 | 125,487 | 125,083 | 124,679 | 124,275 | 123,871 | 123,467 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 216 | 215 | 215 | 214 | 213 | 213 | 212 | 211 | 211 | 210 | 209 | 208 | 2,547 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 888 | 886 | 883 | 880 | 877 | 874 | 872 | 869 | 866 | 863 | 860 | 858 | 10,476 |
| | 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 | 0.009380 | | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 1,512 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $1,634 | $1,631 | $1,628 | $1,624 | $1,620 | $1,617 | $1,614 | $1,610 | $1,607 | $1,603 | $1,599 | $1,596 | $19,383 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $1,634 | $1,631 | $1,628 | $1,624 | $1,620 | $1,617 | $1,614 | $1,610 | $1,607 | $1,603 | $1,599 | $1,596 | $19,383 |

**For Project: CAIR CTs - BARTOW (Project 7.2b)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | (45,265) | (45,623) | (45,981) | (46,339) | (46,697) | (47,055) | (47,413) | (47,771) | (48,129) | (48,487) | (48,845) | (49,203) | (49,561) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $230,082 | $229,724 | $229,366 | $229,008 | $228,650 | $228,292 | $227,934 | $227,576 | $227,218 | $226,860 | $226,502 | $226,144 | $225,786 | |
| 6 | Average Net Investment | | | 229,903 | 229,545 | 229,187 | 228,829 | 228,471 | 228,113 | 227,755 | 227,397 | 227,039 | 226,681 | 226,323 | 225,965 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 388 | 388 | 387 | 386 | 386 | 385 | 385 | 384 | 383 | 383 | 382 | 382 | 4,619 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 1,597 | 1,594 | 1,592 | 1,589 | 1,587 | 1,584 | 1,582 | 1,579 | 1,577 | 1,574 | 1,572 | 1,569 | 18,996 |
| | 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 | 0.009890 | | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 227 | 2,724 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $2,570 | $2,567 | $2,564 | $2,560 | $2,558 | $2,554 | $2,552 | $2,548 | $2,545 | $2,542 | $2,539 | $2,536 | $30,635 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $2,570 | $2,567 | $2,564 | $2,560 | $2,558 | $2,554 | $2,552 | $2,548 | $2,545 | $2,542 | $2,539 | $2,536 | $30,635 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**For Project: CAIR CTs - BAYBORO (Project 7.2c)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (38,655) | (39,039) | (39,423) | (39,807) | (40,191) | (40,575) | (40,959) | (41,343) | (41,727) | (42,111) | (42,495) | (42,879) | (43,263) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $160,333 | $159,949 | $159,565 | $159,181 | $158,797 | $158,413 | $158,029 | $157,645 | $157,261 | $156,877 | $156,493 | $156,109 | $155,725 | |
| 6 | Average Net Investment | | | | 160,141 | 159,757 | 159,373 | 158,989 | 158,605 | 158,221 | 157,837 | 157,453 | 157,069 | 156,685 | 156,301 | 155,917 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 270 | 270 | 269 | 268 | 268 | 267 | 267 | 266 | 265 | 265 | 264 | 263 | 3,202 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 1,112 | 1,110 | 1,107 | 1,104 | 1,102 | 1,099 | 1,096 | 1,094 | 1,091 | 1,088 | 1,086 | 1,083 | 13,172 |
| | 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 | 0.009890 | | | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 164 | 1,968 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $1,930 | $1,928 | $1,924 | $1,920 | $1,918 | $1,914 | $1,911 | $1,908 | $1,904 | $1,901 | $1,898 | $1,894 | $22,950 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $1,930 | $1,928 | $1,924 | $1,920 | $1,918 | $1,914 | $1,911 | $1,908 | $1,904 | $1,901 | $1,898 | $1,894 | $22,950 |

**For Project: CAIR CTs - DeBARY (Project 7.2d)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (22,143) | (22,362) | (22,581) | (22,800) | (23,019) | (23,238) | (23,457) | (23,676) | (23,895) | (24,114) | (24,333) | (24,552) | (24,771) | |
| 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) | | | $65,524 | $65,305 | $65,086 | $64,867 | $64,648 | $64,429 | $64,210 | $63,991 | $63,772 | $63,553 | $63,334 | $63,115 | $62,896 | |
| 6 | Average Net Investment | | | | 65,414 | 65,195 | 64,976 | 64,757 | 64,538 | 64,319 | 64,100 | 63,881 | 63,662 | 63,443 | 63,224 | 63,005 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 110 | 110 | 110 | 109 | 109 | 109 | 108 | 108 | 107 | 107 | 107 | 106 | 1,300 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 454 | 453 | 451 | 450 | 448 | 447 | 445 | 444 | 442 | 441 | 439 | 438 | 5,352 |
| | 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 | 0.011680 | | | 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) | | | | $868 | $867 | $865 | $863 | $861 | $860 | $857 | $856 | $853 | $852 | $850 | $848 | $10,300 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $868 | $867 | $865 | $863 | $861 | $860 | $857 | $856 | $853 | $852 | $850 | $848 | $10,300 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**For Project: CAIR CTs - HIGGINS (Project 7.2e)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | (67,041) | (67,880) | (68,719) | (69,558) | (70,397) | (71,236) | (72,075) | (72,914) | (73,753) | (74,592) | (75,431) | (76,270) | (77,109) | |
| 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) | | $280,157 | $279,318 | $278,479 | $277,640 | $276,801 | $275,962 | $275,123 | $274,284 | $273,445 | $272,606 | $271,767 | $270,928 | $270,089 | |
| 6 | Average Net Investment | | | 279,737 | 278,898 | 278,059 | 277,220 | 276,381 | 275,542 | 274,703 | 273,864 | 273,025 | 272,186 | 271,347 | 270,508 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 472 | 471 | 470 | 468 | 467 | 465 | 464 | 462 | 461 | 460 | 458 | 457 | 5,575 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 1,943 | 1,937 | 1,931 | 1,925 | 1,920 | 1,914 | 1,908 | 1,902 | 1,896 | 1,891 | 1,885 | 1,879 | 22,931 |
| | 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 | 0.009890 | | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 3,432 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $3,540 | $3,533 | $3,526 | $3,518 | $3,512 | $3,504 | $3,497 | $3,489 | $3,482 | $3,476 | $3,468 | $3,461 | $42,006 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $3,540 | $3,533 | $3,526 | $3,518 | $3,512 | $3,504 | $3,497 | $3,489 | $3,482 | $3,476 | $3,468 | $3,461 | $42,006 |

**For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | ($76,123) | (76,910) | (77,697) | (78,484) | (79,271) | (80,058) | (80,845) | (81,632) | (82,419) | (83,206) | (83,993) | (84,780) | (85,567) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $273,461 | $272,674 | $271,887 | $271,100 | $270,313 | $269,526 | $268,739 | $267,952 | $267,165 | $266,378 | $265,591 | $264,804 | $264,017 | |
| 6 | Average Net Investment | | | 273,067 | 272,280 | 271,493 | 270,706 | 269,919 | 269,132 | 268,345 | 267,558 | 266,771 | 265,984 | 265,197 | 264,410 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 461 | 460 | 458 | 457 | 456 | 454 | 453 | 452 | 450 | 449 | 448 | 446 | 5,444 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 1,897 | 1,891 | 1,886 | 1,880 | 1,875 | 1,869 | 1,864 | 1,858 | 1,853 | 1,847 | 1,842 | 1,837 | 22,399 |
| | 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 | 0.008700 | | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 253 | 3,036 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $3,398 | $3,391 | $3,384 | $3,377 | $3,371 | $3,363 | $3,357 | $3,350 | $3,343 | $3,336 | $3,330 | $3,323 | $40,323 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $3,398 | $3,391 | $3,384 | $3,377 | $3,371 | $3,363 | $3,357 | $3,350 | $3,343 | $3,336 | $3,330 | $3,323 | $40,323 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**For Project: CAIR CTs - TURNER (Project 7.2g)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | 134,012 | |
| 3 | Less: Accumulated Depreciation | | | (17,511) | (17,647) | (17,783) | (17,919) | (18,055) | (18,191) | (18,327) | (18,463) | (18,599) | (18,735) | (18,871) | (19,007) | (19,143) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $116,501 | $116,365 | $116,229 | $116,093 | $115,957 | $115,821 | $115,685 | $115,549 | $115,413 | $115,277 | $115,141 | $115,005 | $114,869 | |
| 6 | Average Net Investment | | | | 116,433 | 116,297 | 116,161 | 116,025 | 115,889 | 115,753 | 115,617 | 115,481 | 115,345 | 115,209 | 115,073 | 114,937 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 197 | 196 | 196 | 196 | 196 | 195 | 195 | 195 | 195 | 195 | 194 | 194 | 2,344 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 809 | 808 | 807 | 806 | 805 | 804 | 803 | 802 | 801 | 800 | 799 | 798 | 9,642 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 1.2187% | | | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 1,632 |
| | b. Amortization | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes | 0.011680 | | | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 1,560 |
| | 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 | $1,270 | $1,269 | $1,268 | $1,267 | $1,265 | $1,264 | $1,263 | $1,262 | $1,261 | $1,259 | $1,258 | $15,178 |
| | a. 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 | $1,270 | $1,269 | $1,268 | $1,267 | $1,265 | $1,264 | $1,263 | $1,262 | $1,261 | $1,259 | $1,258 | $15,178 |

**For Project: CAIR CTs - SUWANNEE (Project 7.2h)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (46,038) | (46,461) | (46,884) | (47,307) | (47,730) | (48,153) | (48,576) | (48,999) | (49,422) | (49,845) | (50,268) | (50,691) | (51,114) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $335,522 | $335,099 | $334,676 | $334,253 | $333,830 | $333,407 | $332,984 | $332,561 | $332,138 | $331,715 | $331,292 | $330,869 | $330,446 | |
| 6 | Average Net Investment | | | | 335,310 | 334,887 | 334,464 | 334,041 | 333,618 | 333,195 | 332,772 | 332,349 | 331,926 | 331,503 | 331,080 | 330,657 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 566 | 565 | 565 | 564 | 563 | 563 | 562 | 561 | 560 | 560 | 559 | 558 | 6,746 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 2,329 | 2,326 | 2,323 | 2,320 | 2,317 | 2,314 | 2,311 | 2,308 | 2,305 | 2,303 | 2,300 | 2,297 | 27,753 |
| | 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 | 0.008630 | | | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 3,288 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $3,592 | $3,588 | $3,585 | $3,581 | $3,577 | $3,574 | $3,570 | $3,566 | $3,562 | $3,560 | $3,556 | $3,552 | $42,863 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $3,592 | $3,588 | $3,585 | $3,581 | $3,577 | $3,574 | $3,570 | $3,566 | $3,562 | $3,560 | $3,556 | $3,552 | $42,863 |

(A) The allowable return is per the methodology approved in Order No. PSC-12-0425-PAA-EU.

**For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)**
**(in Dollars)**

DUKE ENERGY FLORIDA, LLC

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $713,122 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | | $2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | 2,169,955 | |
| 3 | Less: Accumulated Depreciation | | | (23,075) | (27,541) | (32,007) | (36,473) | (40,939) | (45,405) | (49,871) | (54,337) | (58,803) | (63,269) | (67,735) | (72,201) | (76,667) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 59,427 | 118,854 | 178,281 | 237,707 | 297,134 | 356,561 | 415,988 | 475,415 | 534,842 | 594,268 | 653,695 | 713,122 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $2,146,880 | $2,201,841 | $2,256,802 | $2,311,763 | $2,366,723 | $2,421,684 | $2,476,645 | $2,531,606 | $2,586,567 | $2,641,528 | $2,696,488 | $2,751,449 | $2,806,410 | |
| 6 | Average Net Investment | | | | 2,174,361 | 2,229,321 | 2,284,282 | 2,339,243 | 2,394,204 | 2,449,165 | 2,504,126 | 2,559,086 | 2,614,047 | 2,669,008 | 2,723,969 | 2,778,930 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 3,671 | 3,764 | 3,857 | 3,950 | 4,043 | 4,135 | 4,228 | 4,321 | 4,414 | 4,507 | 4,599 | 4,692 | 50,181 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 15,103 | 15,484 | 15,866 | 16,248 | 16,630 | 17,011 | 17,393 | 17,775 | 18,156 | 18,538 | 18,920 | 19,302 | 206,426 |
| | c. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | | |
| | a. Depreciation | 2.4700% | | | 4,466 | 4,466 | 4,466 | 4,466 | 4,466 | 4,466 | 4,466 | 4,466 | 4,466 | 4,466 | 4,466 | 4,466 | 53,592 |
| | 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 | 0.001703 | | | 308 | 308 | 308 | 308 | 308 | 308 | 308 | 308 | 308 | 308 | 308 | 308 | 3,696 |
| | e. Other | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | | $23,548 | $24,022 | $24,497 | $24,972 | $25,447 | $25,920 | $26,395 | $26,870 | $27,344 | $27,819 | $28,293 | $28,768 | $313,895 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $23,548 | $24,022 | $24,497 | $24,972 | $25,447 | $25,920 | $26,395 | $26,870 | $27,344 | $27,819 | $28,293 | $28,768 | $313,895 |

**For Project: Crystal River 4 and 5 - Conditions of Certification (Project 7.4q)**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (18,629) | (19,389) | (20,149) | (20,909) | (21,669) | (22,429) | (23,189) | (23,949) | (24,709) | (25,469) | (26,229) | (26,989) | (27,749) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $595,381 | $594,621 | $593,861 | $593,101 | $592,341 | $591,581 | $590,821 | $590,061 | $589,301 | $588,541 | $587,781 | $587,021 | $586,261 | |
| 6 | Average Net Investment | | | | 595,001 | 594,241 | 593,481 | 592,721 | 591,961 | 591,201 | 590,441 | 589,681 | 588,921 | 588,161 | 587,401 | 586,641 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 1,005 | 1,003 | 1,002 | 1,001 | 1,000 | 998 | 997 | 996 | 994 | 993 | 992 | 991 | 11,972 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 4,133 | 4,127 | 4,122 | 4,117 | 4,112 | 4,106 | 4,101 | 4,096 | 4,090 | 4,085 | 4,080 | 4,075 | 49,244 |
| | 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) | | | | $5,985 | $5,977 | $5,971 | $5,965 | $5,959 | $5,951 | $5,945 | $5,939 | $5,931 | $5,925 | $5,919 | $5,913 | $71,380 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $5,985 | $5,977 | $5,971 | $5,965 | $5,959 | $5,951 | $5,945 | $5,939 | $5,931 | $5,925 | $5,919 | $5,913 | $71,380 |

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-13-0598-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-12-0425-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (43,955) | (45,316) | (46,677) | (48,038) | (49,399) | (50,760) | (52,121) | (53,482) | (54,843) | (56,204) | (57,565) | (58,926) | (60,287) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $617,043 | $615,682 | $614,321 | $612,960 | $611,599 | $610,238 | $608,877 | $607,516 | $606,155 | $604,794 | $603,433 | $602,072 | $600,711 | |
| 6 | Average Net Investment | | | | 616,363 | 615,002 | 613,641 | 612,280 | 610,919 | 609,558 | 608,197 | 606,836 | 605,475 | 604,114 | 602,753 | 601,392 | |
| 7 | Return on Average Net Investment (A) | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 1,041 | 1,038 | 1,036 | 1,034 | 1,032 | 1,029 | 1,027 | 1,025 | 1,022 | 1,020 | 1,018 | 1,015 | 12,337 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 4,281 | 4,272 | 4,262 | 4,253 | 4,243 | 4,234 | 4,224 | 4,215 | 4,205 | 4,196 | 4,187 | 4,177 | 50,749 |
| | 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) | | | | $6,777 | $6,765 | $6,753 | $6,742 | $6,730 | $6,718 | $6,706 | $6,695 | $6,682 | $6,671 | $6,660 | $6,647 | $80,546 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $6,777 | $6,765 | $6,753 | $6,742 | $6,730 | $6,718 | $6,706 | $6,695 | $6,682 | $6,671 | $6,660 | $6,647 | $80,546 |

**For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4s) - CR5 Clinker Mitigation**
**(in Dollars)**

| Line | Description | | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | | | (20,810) | (21,851) | (22,892) | (23,933) | (24,974) | (26,015) | (27,056) | (28,097) | (29,138) | (30,179) | (31,220) | (32,261) | (33,302) | |
| 4 | CWIP - Non-Interest Bearing | | | 0 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | 135,074 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | | $485,094 | $619,127 | $618,086 | $617,045 | $616,004 | $614,963 | $613,922 | $612,881 | $611,840 | $610,799 | $609,758 | $608,717 | $607,676 | |
| 6 | Return on Average Net Investment (A) | | | | 552,111 | 618,607 | 617,566 | 616,525 | 615,484 | 614,443 | 613,402 | 612,361 | 611,320 | 610,279 | 609,238 | 608,197 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | | | |
| | a. Debt Component | | 2.03% | | 932 | 1,045 | 1,043 | 1,041 | 1,039 | 1,037 | 1,036 | 1,034 | 1,032 | 1,030 | 1,029 | 1,027 | 12,325 |
| | b. Equity Component Grossed Up For Taxes | | 8.33% | | 3,835 | 4,297 | 4,289 | 4,282 | 4,275 | 4,268 | 4,261 | 4,253 | 4,246 | 4,239 | 4,232 | 4,224 | 50,701 |
| | 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) | | | | $5,880 | $6,455 | $6,445 | $6,436 | $6,427 | $6,418 | $6,410 | $6,400 | $6,391 | $6,382 | $6,374 | $6,364 | $76,382 |
| | a. Recoverable Costs Allocated to Energy | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | | $5,880 | $6,455 | $6,445 | $6,436 | $6,427 | $6,418 | $6,410 | $6,400 | $6,391 | $6,382 | $6,374 | $6,364 | $76,382 |

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-13-0598-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-12-0425-PAA-EU.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Commission Forms 42-1P Through 42-8P**

**January 2016 - December 2016**
**Calculation of Projected Period Amount**

**Docket No. 150007-EI**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 16
PARTY: DUKE ENERGY FLORIDA, LLC
(DEF) – (DIRECT)
DESCRIPTION: Garry Miller TGF-5

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

| 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) | $42,339,858 | $329,256 | $621,710 | $876,120 | $44,166,944 |
| b | Projected Capital Projects (Form 42-3P, Lines 7 through 9) | 22,049,877 | 0 | 1,414 | 3,176,702 | 25,227,993 |
| c | Total Jurisdictional Rev Req for the Projected Period (Lines 1a + 1b) | 64,389,735 | 329,256 | 623,124 | 4,052,822 | 69,394,937 |
| 2 | True-up for Estimated Over/(Under) Recovery for the Current Period January 2015 - December 2015 (Form 42-2E, Line 5 + 6 + 10) | (1,720,135) | (350,923) | 885,148 | 406,308 | (779,602) |
| 3 | Final True-up for the Period January 2014 - December 2014 (Form 42-1A, Line 3) | 1,428,470 | (98,371) | 4,238 | 84,706 | 1,419,043 |
| 4 | Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection Period January 2016 - December 2016 (Line 1 - Line 2 - Line 3) | 64,681,400 | 778,551 | (266,263) | 3,561,808 | 68,755,496 |
| 5 | Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072) | $64,727,970 | $779,111 | ($266,454) | $3,564,373 | $68,805,000 |

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**O&M Activities**
**(in Dollars)**

Form 42-2P

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)


| Line | Description | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | O&M Activities - System | | | | | | | | | | | | | |
| 1 | Transmission Substation Environmental Investigation, Remediation and Pollution Prevention | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $469,000 |
| 1a | Distribution Substation Environmental Investigation, Remediation and Pollution Prevention | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 621,000 |
| 2 | Distribution System Environmental Investigation, Remediation and Pollution Prevention | 3,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,000 |
| 3 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 51,723 | 51,723 | 51,723 | 51,723 | 695,676 |
| 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 | 8,824 | 8,824 | 10,978 | 8,657 | 9,562 | 9,661 | 9,921 | 9,934 | 9,931 | 8,793 | 7,740 | 8,223 | 111,050 |
| 5 | NOx Emissions Allowances Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 6 | Phase II Cooling Water Intake 316(b) - Base | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 250,000 |
| 6a | Phase II Cooling Water Intake 316(b) - Intm | 20,500 | 20,500 | 20,500 | 20,500 | 20,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 190,000 |
| 7.2 | CAIR/CAMR - Peaking | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 31,850 | 0 | 66,109 | 0 | 134,459 |
| 7.4 | CAIR/CAMR Crystal River - Base | 1,119,721 | 3,452,919 | 1,914,869 | 1,317,818 | 1,346,472 | 1,114,151 | 1,120,802 | 1,088,803 | 1,326,571 | 1,200,915 | 1,221,061 | 1,105,970 | 17,330,071 |
| 7.4 | CAIR/CAMR Crystal River - Energy | 1,421,824 | 1,336,488 | 1,001,927 | 1,382,142 | 1,426,980 | 1,465,949 | 1,456,055 | 1,483,137 | 1,483,419 | 1,514,175 | 1,311,791 | 1,499,939 | 16,783,826 |
| 7.4 | CAIR/CAMR Crystal River - A&G | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 141,192 |
| 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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Sea Turtle - Coastal Street Lighting - Distrib | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 50 | 50 | 50 | 0 | 0 | 450 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Energy | 0 | 0 | 18,232 | 0 | 4,290 | 7,500 | 0 | 0 | 18,232 | 0 | 4,290 | 7,500 | 60,044 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 48,283 | 48,283 | 43,283 | 43,283 | 529,400 |
| 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 | 266,003 | 266,003 | 406,003 | 542,253 | 366,003 | 266,003 | 302,253 | 266,003 | 266,003 | 302,253 | 266,003 | 266,003 | 3,780,792 |
| 18 | Coal Combustion Residual (CCR) Rule - Energy (C) | 150,333 | 75,333 | 75,333 | 294,083 | 294,083 | 294,083 | 294,083 | 75,333 | 75,333 | 75,333 | 50,333 | 50,333 | 1,804,000 |
| 2 | Total O&M Activities - Recoverable Costs | $3,512,115 | $5,718,478 | $3,994,753 | $4,087,364 | $3,989,901 | $3,716,858 | $3,717,624 | $3,457,671 | $3,766,426 | $3,631,555 | $3,452,362 | $3,488,005 | $46,533,115 |
| 3 | Recoverable Costs Allocated to Energy | 1,890,267 | 1,729,932 | 1,555,758 | 2,270,419 | 2,144,202 | 2,086,481 | 2,105,596 | 1,877,691 | 1,901,203 | 1,948,838 | 1,683,441 | 1,875,283 | 23,069,111 |
| | Recoverable Costs Allocated to Energy - NOx Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 4 | Recoverable Costs Allocated to Demand - Transm | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 469,000 |
| | Recoverable Costs Allocated to Demand - Distrib | 54,750 | 51,750 | 51,750 | 51,750 | 51,850 | 51,850 | 51,850 | 51,800 | 51,800 | 51,800 | 51,750 | 51,750 | 624,450 |
| | Recoverable Costs Allocated to Demand - Prod-Base | 1,132,221 | 3,465,419 | 1,952,369 | 1,330,318 | 1,358,972 | 1,151,651 | 1,133,302 | 1,101,303 | 1,364,071 | 1,213,415 | 1,233,561 | 1,143,470 | 17,580,071 |
| | Recoverable Costs Allocated to Demand - Prod-Intm | 81,598 | 81,598 | 81,598 | 81,598 | 81,598 | 73,598 | 73,598 | 73,598 | 64,223 | 64,223 | 64,223 | 64,223 | 885,676 |
| | Recoverable Costs Allocated to Demand - Prod-Peaking | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 31,850 | 0 | 66,109 | 0 | 134,459 |
| | Recoverable Costs Allocated to Demand - A&G | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 141,192 |
| 5 | Retail Energy Jurisdictional Factor | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | 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) | 1,849,176 | 1,689,187 | 1,529,691 | 2,220,389 | 2,084,201 | 2,025,099 | 2,037,318 | 1,812,034 | 1,837,596 | 1,884,537 | 1,627,322 | 1,831,640 | 22,428,190 |
| | Retail Energy Jurisdictional Factor - NOx Regulatory Asset (A) | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 8 | Jurisdictional Demand Recoverable Costs - Transm (B) | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 329,256 |
| | Jurisdictional Demand Recoverable Costs - Distrib (B) | 54,510 | 51,523 | 51,523 | 51,523 | 51,622 | 51,622 | 51,622 | 51,573 | 51,573 | 51,573 | 51,523 | 51,523 | 621,710 |
| | Jurisdictional Demand Recoverable Costs - Prod-Base (B) | 1,051,663 | 3,218,854 | 1,813,458 | 1,235,666 | 1,262,281 | 1,069,711 | 1,052,667 | 1,022,945 | 1,267,018 | 1,127,081 | 1,145,793 | 1,062,112 | 16,329,249 |
| | Jurisdictional Demand Recoverable Costs - Prod-Intm (B) | 59,324 | 59,324 | 59,324 | 59,324 | 59,324 | 53,508 | 53,508 | 53,508 | 46,692 | 46,692 | 46,692 | 46,692 | 643,912 |
| | Jurisdictional Demand Recoverable Costs - Prod-Peaking (B) | 0 | 35,012 | 0 | 0 | 0 | 0 | 0 | 0 | 30,552 | 0 | 63,414 | 0 | 128,978 |
| | Jurisdictional Demand Recoverable Costs - A&G (B) | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 131,616 |
| 9 | Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8) | $3,349,248 | $5,388,475 | $3,788,571 | $3,901,477 | $3,792,003 | $3,534,515 | $3,529,690 | $3,274,635 | $3,568,006 | $3,444,458 | $3,269,319 | $3,326,542 | $44,166,944 |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6
(C) As explained in the testimony of Garry Miller, $75K of 2015 temporary dust mitigation resulting from shift of permanent capital solution from October 2015 to October 2016 is included in Jan-16.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Capital Investment Projects-Recoverable Costs**
**(in Dollars)**

Form 42-3P

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)


| Line | Description | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investment Projects - System (A) | | | | | | | | | | | | | |
| 3.1 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| 4.1 | Above Ground Tank Secondary Containment - Peaking | 116,357 | 116,069 | 115,781 | 115,496 | 115,208 | 114,921 | 114,635 | 114,348 | 114,060 | 113,774 | 113,486 | 113,199 | 1,377,334 |
| 4.2 | Above Ground Tank Secondary Containment - Base | 24,937 | 24,911 | 24,885 | 24,858 | 24,832 | 24,806 | 24,780 | 24,754 | 24,728 | 24,702 | 24,676 | 24,649 | 297,518 |
| 4.3 | Above Ground Tank Secondary Containment - Intm | 2,700 | 2,696 | 2,691 | 2,687 | 2,683 | 2,678 | 2,674 | 2,669 | 2,664 | 2,660 | 2,655 | 2,650 | 32,107 |
| 5 | SO2/NOX Emissions Allowances - Energy | 90,075 | 87,387 | 84,690 | 81,995 | 79,305 | 76,610 | 73,915 | 71,217 | 68,521 | 65,828 | 63,146 | 60,466 | 903,155 |
| 7.1 | CAIR/CAMR Anclote- Intm | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.2 | CAIR/CAMR - Peaking | 18,804 | 18,775 | 18,745 | 18,711 | 18,684 | 18,651 | 18,622 | 18,590 | 18,558 | 18,531 | 18,499 | 18,468 | 223,638 |
| 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 | 42,190 | 43,219 | 43,666 | 44,115 | 44,563 | 45,007 | 45,456 | 45,904 | 46,348 | 46,797 | 47,246 | 47,692 | 542,203 |
| 7.4 | CAIR/CAMR Crystal River AFUDC - Energy | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 112,443 |
| 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 | 115 | 116 | 116 | 116 | 116 | 117 | 118 | 119 | 120 | 123 | 122 | 122 | 1,420 |
| 10.1 | Underground Storage Tanks - Base | 1,569 | 1,567 | 1,564 | 1,562 | 1,559 | 1,557 | 1,554 | 1,552 | 1,548 | 1,546 | 1,543 | 1,541 | 18,662 |
| 10.2 | Underground Storage Tanks - Intm | 733 | 731 | 730 | 728 | 726 | 725 | 722 | 721 | 720 | 717 | 716 | 714 | 8,683 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Intm | 154,003 | 153,692 | 153,383 | 153,073 | 152,763 | 152,453 | 152,143 | 151,833 | 151,523 | 151,214 | 150,903 | 150,593 | 1,827,576 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 37,668 | 37,612 | 37,555 | 37,499 | 37,443 | 37,386 | 37,330 | 37,273 | 37,217 | 37,160 | 37,103 | 37,047 | 448,291 |
| 17.1 | Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - | 1,430,070 | 1,427,963 | 1,425,857 | 1,423,751 | 1,421,646 | 1,419,540 | 1,417,433 | 1,415,327 | 1,413,221 | 1,411,115 | 1,409,009 | 1,406,902 | 17,021,828 |
| 17.2 | Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy | 246,827 | 250,632 | 257,005 | 262,083 | 263,275 | 279,122 | 278,455 | 277,789 | 277,122 | 276,456 | 275,790 | 275,123 | 3,219,684 |
| 18 | Coal Combustion Residual (CCR) Rule - Energy | (56,167) | 4,608 | 7,680 | 10,753 | 13,824 | 16,896 | 19,968 | 23,041 | 26,113 | 29,184 | 35,878 | 37,137 | 168,915 |
| 2 | Total Investment Projects - Recoverable Costs | $2,142,842 | $2,202,887 | $2,207,210 | $2,210,241 | $2,209,391 | $2,223,184 | $2,220,473 | $2,217,755 | $2,215,033 | $2,212,328 | $2,213,244 | $2,208,729 | $26,483,317 |
| 3 | Recoverable Costs Allocated to Energy | 1,757,843 | 1,817,572 | 1,822,157 | 1,825,451 | 1,824,863 | 1,838,924 | 1,836,471 | 1,834,017 | 1,831,564 | 1,829,113 | 1,830,296 | 1,826,045 | 21,874,316 |
| | Recoverable Costs Allocated to Distribution Demand | 115 | 116 | 116 | 116 | 116 | 117 | 118 | 119 | 120 | 123 | 122 | 122 | 1,420 |
| 4 | Recoverable Costs Allocated to Demand - Production - Base | 68,696 | 69,697 | 70,115 | 70,535 | 70,954 | 71,370 | 71,790 | 72,210 | 72,624 | 73,045 | 73,465 | 73,882 | 858,383 |
| | Recoverable Costs Allocated to Demand - Production - Intermediate | 181,027 | 180,658 | 180,296 | 179,932 | 179,566 | 179,201 | 178,837 | 178,471 | 178,107 | 177,742 | 177,376 | 177,013 | 2,148,226 |
| | Recoverable Costs Allocated to Demand - Production - Peaking | 135,161 | 134,844 | 134,526 | 134,207 | 133,892 | 133,572 | 133,257 | 132,938 | 132,618 | 132,305 | 131,985 | 131,667 | 1,600,972 |
| | Recoverable Costs Allocated to Demand - Production - Base (2012) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | Retail Energy Jurisdictional Factor | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | 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) | 1,719,630 | 1,774,762 | 1,791,627 | 1,785,225 | 1,773,798 | 1,784,825 | 1,776,920 | 1,769,887 | 1,770,287 | 1,768,762 | 1,769,281 | 1,783,548 | 21,268,554 |
| | Jurisdictional Demand Recoverable Costs - Distribution (B) | 114 | 115 | 115 | 115 | 115 | 116 | 117 | 118 | 119 | 122 | 121 | 121 | 1,414 |
| 8 | Jurisdictional Demand Recoverable Costs - Production - Base (C) | 63,808 | 64,738 | 65,126 | 65,516 | 65,906 | 66,292 | 66,682 | 67,072 | 67,457 | 67,848 | 68,238 | 68,625 | 797,309 |
| | Jurisdictional Demand Recoverable Costs - Production - Intermediate (C) | 131,612 | 131,344 | 131,081 | 130,816 | 130,550 | 130,285 | 130,020 | 129,754 | 129,489 | 129,224 | 128,958 | 128,694 | 1,561,825 |
| | Jurisdictional Demand Recoverable Costs - Production - Peaking (C) | 129,652 | 129,348 | 129,043 | 128,737 | 128,435 | 128,128 | 127,825 | 127,519 | 127,212 | 126,912 | 126,605 | 126,300 | 1,535,716 |
| | Jurisdictional Demand Recoverable Costs - Production - Base (2012) (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8) | $2,044,817 | $2,100,308 | $2,116,992 | $2,110,410 | $2,098,803 | $2,109,646 | $2,101,565 | $2,094,351 | $2,094,565 | $2,092,869 | $2,093,204 | $2,107,289 | $25,164,818 |

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, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | |
| 3 | Less: Accumulated Depreciation | (777,505) | (783,149) | (788,793) | (794,437) | (800,081) | (805,725) | (811,369) | (817,013) | (822,657) | (828,301) | (833,945) | (839,589) | (845,233) | |
| 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) | $1,837,200 | $1,831,556 | $1,825,912 | $1,820,268 | $1,814,624 | $1,808,980 | $1,803,336 | $1,797,692 | $1,792,048 | $1,786,404 | $1,780,760 | $1,775,116 | $1,769,472 | |
| 6 | Average Net Investment | | $1,834,378 | $1,828,734 | $1,823,090 | $1,817,446 | $1,811,802 | $1,806,158 | $1,800,514 | $1,794,870 | $1,789,226 | $1,783,582 | $1,777,938 | $1,772,294 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 3,098 | 3,087 | 3,078 | 3,069 | 3,059 | 3,050 | 3,040 | 3,031 | 3,021 | 3,012 | 3,002 | 2,994 | 36,541 |
| | b. Equity Component Grossed Up For Taxes | | 12,742 | 12,701 | 12,663 | 12,624 | 12,584 | 12,544 | 12,507 | 12,466 | 12,428 | 12,388 | 12,349 | 12,311 | 150,307 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 67,728 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 25,284 |
| | e. Other (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| 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) | | 17,151 | 17,114 | 17,079 | 17,044 | 17,008 | 16,973 | 16,938 | 16,902 | 16,867 | 16,831 | 16,796 | 16,762 | 203,467 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $17,151 | $17,114 | $17,079 | $17,044 | $17,008 | $16,973 | $16,938 | $16,902 | $16,867 | $16,831 | $16,796 | $16,762 | $203,467 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | |
| 3 | Less: Accumulated Depreciation | (2,805,915) | (2,839,142) | (2,872,369) | (2,905,596) | (2,938,823) | (2,972,050) | (3,005,277) | (3,038,504) | (3,071,731) | (3,104,958) | (3,138,185) | (3,171,412) | (3,204,639) | |
| 4 | CWIP - Non-Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $8,495,889 | $8,462,662 | $8,429,435 | $8,396,208 | $8,362,981 | $8,329,754 | $8,296,527 | $8,263,300 | $8,230,073 | $8,196,846 | $8,163,619 | $8,130,392 | $8,097,165 | |
| 6 | Average Net Investment | | $8,479,275 | $8,446,048 | $8,412,821 | $8,379,594 | $8,346,367 | $8,313,140 | $8,279,913 | $8,246,686 | $8,213,459 | $8,180,232 | $8,147,005 | $8,113,778 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 14,317 | 14,261 | 14,205 | 14,148 | 14,093 | 14,037 | 13,980 | 13,924 | 13,867 | 13,812 | 13,755 | 13,699 | 168,098 |
| | b. Equity Component Grossed Up For Taxes | | 58,896 | 58,664 | 58,432 | 58,204 | 57,971 | 57,740 | 57,511 | 57,280 | 57,049 | 56,818 | 56,587 | 56,356 | 691,508 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 398,724 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 119,004 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $116,357 | $116,069 | $115,781 | $115,496 | $115,208 | $114,921 | $114,635 | $114,348 | $114,060 | $113,774 | $113,486 | $113,199 | $1,377,334 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $116,357 | $116,069 | $115,781 | $115,496 | $115,208 | $114,921 | $114,635 | $114,348 | $114,060 | $113,774 | $113,486 | $113,199 | $1,377,334 |
| 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) | | 111,614 | 111,338 | 111,062 | 110,788 | 110,512 | 110,237 | 109,962 | 109,687 | 109,411 | 109,137 | 108,860 | 108,585 | 1,321,194 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $111,614 | $111,338 | $111,062 | $110,788 | $110,512 | $110,237 | $109,962 | $109,687 | $109,411 | $109,137 | $108,860 | $108,585 | $1,321,194 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | 100,001 | 96,969 | 93,937 | 90,905 | 87,873 | 84,841 | 81,809 | 78,777 | 75,745 | 72,713 | 69,681 | 66,649 | 63,617 | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | $2,499,040 | $2,496,008 | $2,492,976 | $2,489,944 | $2,486,912 | $2,483,880 | $2,480,848 | $2,477,816 | $2,474,784 | $2,471,752 | $2,468,720 | $2,465,688 | $2,462,656 | |
| 6 | Average Net Investment | | $2,497,524 | $2,494,492 | $2,491,460 | $2,488,428 | $2,485,396 | $2,482,364 | $2,479,332 | $2,476,300 | $2,473,268 | $2,470,236 | $2,467,204 | $2,464,172 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 4,217 | 4,212 | 4,207 | 4,201 | 4,196 | 4,191 | 4,186 | 4,181 | 4,177 | 4,171 | 4,166 | 4,161 | 50,266 |
| | b. Equity Component Grossed Up For Taxes | | 17,347 | 17,326 | 17,305 | 17,284 | 17,263 | 17,242 | 17,221 | 17,200 | 17,178 | 17,158 | 17,137 | 17,115 | 206,776 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 36,384 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 4,092 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $24,937 | $24,911 | $24,885 | $24,858 | $24,832 | $24,806 | $24,780 | $24,754 | $24,728 | $24,702 | $24,676 | $24,649 | $297,518 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $24,937 | $24,911 | $24,885 | $24,858 | $24,832 | $24,806 | $24,780 | $24,754 | $24,728 | $24,702 | $24,676 | $24,649 | $297,518 |
| 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) | | 23,163 | 23,139 | 23,114 | 23,089 | 23,065 | 23,041 | 23,017 | 22,993 | 22,969 | 22,944 | 22,920 | 22,895 | 276,350 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $23,163 | $23,139 | $23,114 | $23,089 | $23,065 | $23,041 | $23,017 | $22,993 | $22,969 | $22,944 | $22,920 | $22,895 | $276,350 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | (60,186) | (60,711) | (61,236) | (61,761) | (62,286) | (62,811) | (63,336) | (63,861) | (64,386) | (64,911) | (65,436) | (65,961) | (66,486) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | $230,112 | $229,587 | $229,062 | $228,537 | $228,012 | $227,487 | $226,962 | $226,437 | $225,912 | $225,387 | $224,862 | $224,337 | $223,812 | |
| 6 | Average Net Investment | | $229,849 | $229,324 | $228,799 | $228,274 | $227,749 | $227,224 | $226,699 | $226,174 | $225,649 | $225,124 | $224,599 | $224,074 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 388 | 387 | 386 | 385 | 385 | 384 | 383 | 382 | 381 | 380 | 379 | 378 | 4,598 |
| | b. Equity Component Grossed Up For Taxes | | 1,596 | 1,593 | 1,589 | 1,586 | 1,582 | 1,578 | 1,575 | 1,571 | 1,567 | 1,564 | 1,560 | 1,556 | 18,917 |
| | 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) | | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 2,292 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |
| 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) | | 1,963 | 1,960 | 1,956 | 1,954 | 1,951 | 1,947 | 1,944 | 1,940 | 1,937 | 1,934 | 1,930 | 1,927 | 23,343 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $1,963 | $1,960 | $1,956 | $1,954 | $1,951 | $1,947 | $1,944 | $1,940 | $1,937 | $1,934 | $1,930 | $1,927 | $23,343 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0158150 $SO_2$ Emission Allowance Inventory | | $3,333,608 | $3,324,785 | $3,315,961 | $3,304,982 | $3,296,584 | $3,287,013 | $3,277,343 | $3,267,414 | $3,257,471 | $3,247,532 | $3,238,730 | $3,230,982 | $3,222,750 | $3,222,750 |
| | b. 0254020 Auctioned $SO_2$ Allowance | | (4,039) | (4,039) | (4,039) | (4,039) | (4,298) | (4,289) | (4,281) | (4,272) | (4,264) | (4,256) | (4,247) | (4,239) | (4,230) | (4,230) |
| | c. 0158170 NOx Emission Allowance Inventory | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Other (A) | | 7,258,313 | 6,955,883 | 6,653,453 | 6,351,024 | 6,048,594 | 5,746,164 | 5,443,735 | 5,141,305 | 4,838,875 | 4,536,446 | 4,234,016 | 3,931,586 | 3,629,156 | 3,629,156 |
| 2 | Total Working Capital | | $10,587,882 | $10,276,629 | $9,965,375 | $9,651,967 | $9,340,880 | $9,028,888 | $8,716,797 | $8,404,447 | $8,092,083 | $7,779,722 | $7,468,499 | $7,158,329 | $6,847,676 | $6,847,676 |
| 3 | Average Net Investment | | | $10,432,255 | $10,121,002 | $9,808,671 | $9,496,424 | $9,184,884 | $8,872,843 | $8,560,622 | $8,248,265 | $7,935,902 | $7,624,110 | $7,313,414 | $7,003,003 | |
| 4 | Return on Average Net Working Capital Balance (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 17,615 | 17,089 | 16,562 | 16,035 | 15,509 | 14,982 | 14,455 | 13,927 | 13,400 | 12,873 | 12,349 | 11,825 | 176,621 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 72,460 | 70,298 | 68,128 | 65,960 | 63,796 | 61,628 | 59,460 | 57,290 | 55,121 | 52,955 | 50,797 | 48,641 | 726,534 |
| 5 | Total Return Component (C) | | | $90,075 | $87,387 | $84,690 | $81,995 | $79,305 | $76,610 | $73,915 | $71,217 | $68,521 | $65,828 | $63,146 | $60,466 | 903,155 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0509030 $SO_2$ Allowance Expense | | | $8,824 | $8,824 | $10,978 | $8,399 | $9,571 | $9,670 | $9,929 | $9,943 | $9,940 | $8,802 | $7,748 | $8,232 | 110,858 |
| | b. 0407426 Amortization Expense | | | 0 | 0 | 0 | 259 | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | 191 |
| | 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) | | | 8,824 | 8,824 | 10,978 | 8,657 | 9,562 | 9,661 | 9,921 | 9,934 | 9,931 | 8,793 | 7,740 | 8,223 | 111,050 |
| 8 | Amortization of NOx CAIR Emission Allowances (A) | | | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | 3,629,156 |
| 9 | Total System Recoverable Expenses (Lines 5 + 7) | | | $401,328 | $398,641 | $398,098 | $393,082 | $391,297 | $388,701 | $386,265 | $383,581 | $380,882 | $377,051 | $373,316 | $371,119 | |
| | a. Recoverable Costs Allocated to Energy | | | 98,899 | 96,211 | 95,668 | 90,652 | 88,867 | 86,271 | 83,836 | 81,151 | 78,452 | 74,621 | 70,886 | 68,689 | |
| | b. Recoverable Costs Allocated to Energy - NOx CAIR Emisssion Allowances (A) | | | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | |
| 10 | a. Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | b. NOx Regulatory Asset Energy Factor (12/2014) (A) | | | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | |
| 11 | Retail Energy-Related Recoverable Costs (E) | | | $96,749 | $93,945 | $94,065 | $88,654 | $86,381 | $83,733 | $81,117 | $78,314 | $75,828 | $72,159 | $68,523 | $67,091 | 986,559 |
| 12 | Retail Demand-Related Recoverable Costs (F) | | | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 13 | Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | | $ 392,918 | $ 390,114 | $ 390,235 | $ 384,824 | $ 382,550 | $ 379,903 | $ 377,287 | $ 374,483 | $ 371,997 | $ 368,329 | $ 364,692 | $ 363,260 | $ 4,540,592 |

Notes:

(A) Unusable NOx emission allowances due expiration of Clean Air Interstate Rule (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 conisistent with Order No. PSC-11-0553-FOF-EI.

(B) Line 3 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) Line 5 is reported on Capital Schedule

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

(E) Line 9a x Line 10a

(F) Line 9b x Line 10b

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | |
| 3 | Less: Accumulated Depreciation | (346,416) | (349,966) | (353,516) | (357,066) | (360,616) | (364,166) | (367,716) | (371,266) | (374,816) | (378,366) | (381,916) | (385,466) | (389,016) | |
| 4 | CWIP - Non-Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $1,589,692 | $1,586,142 | $1,582,592 | $1,579,042 | $1,575,492 | $1,571,942 | $1,568,392 | $1,564,842 | $1,561,292 | $1,557,742 | $1,554,192 | $1,550,642 | $1,547,092 | |
| 6 | Average Net Investment | | $1,587,917 | $1,584,367 | $1,580,817 | $1,577,267 | $1,573,717 | $1,570,167 | $1,566,617 | $1,563,067 | $1,559,517 | $1,555,967 | $1,552,417 | $1,548,867 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 2,680 | 2,675 | 2,670 | 2,662 | 2,658 | 2,651 | 2,646 | 2,639 | 2,632 | 2,629 | 2,621 | 2,614 | 31,777 |
| | b. Equity Component Grossed Up For Taxes | | 11,029 | 11,005 | 10,980 | 10,954 | 10,931 | 10,905 | 10,881 | 10,856 | 10,831 | 10,807 | 10,783 | 10,759 | 130,721 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 42,600 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 18,540 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $18,804 | $18,775 | $18,745 | $18,711 | $18,684 | $18,651 | $18,622 | $18,590 | $18,558 | $18,531 | $18,499 | $18,468 | 223,638 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $18,804 | $18,775 | $18,745 | $18,711 | $18,684 | $18,651 | $18,622 | $18,590 | $18,558 | $18,531 | $18,499 | $18,468 | 223,638 |
| 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) | | 18,038 | 18,010 | 17,981 | 17,948 | 17,922 | 17,891 | 17,863 | 17,832 | 17,802 | 17,776 | 17,745 | 17,715 | 214,523 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $18,038 | $18,010 | $17,981 | $17,948 | $17,922 | $17,891 | $17,863 | $17,832 | $17,802 | $17,776 | $17,745 | $17,715 | $214,523 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $713,122 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | |
| 3 | Less: Accumulated Depreciation | (106,469) | (114,097) | (121,725) | (129,353) | (136,981) | (144,609) | (152,237) | (159,865) | (167,493) | (175,121) | (182,749) | (190,377) | (198,005) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 59,427 | 118,854 | 178,281 | 237,707 | 297,134 | 356,561 | 415,988 | 475,415 | 534,842 | 594,268 | 653,695 | 713,122 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $3,844,399 | $3,896,197 | $3,947,996 | $3,999,795 | $4,051,594 | $4,103,393 | $4,155,192 | $4,206,990 | $4,258,789 | $4,310,588 | $4,362,387 | $4,414,186 | $4,465,985 | |
| 6 | Average Net Investment | | $3,870,298 | $3,922,097 | $3,973,896 | $4,025,694 | $4,077,493 | $4,129,292 | $4,181,091 | $4,232,890 | $4,284,689 | $4,336,487 | $4,388,286 | $4,440,085 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 6,649 | 6,850 | 6,938 | 7,026 | 7,114 | 7,199 | 7,288 | 7,376 | 7,462 | 7,550 | 7,638 | 7,725 | 86,815 |
| | b. Equity Component Grossed Up For Taxes | | 27,352 | 28,180 | 28,539 | 28,900 | 29,260 | 29,619 | 29,979 | 30,339 | 30,697 | 31,058 | 31,419 | 31,778 | 357,120 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 91,536 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (D) | | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 6,732 |
| | e. Other | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $42,190 | $43,219 | $43,666 | $44,115 | $44,563 | $45,007 | $45,456 | $45,904 | $46,348 | $46,797 | $47,246 | $47,692 | 542,203 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $42,190 | $43,219 | $43,666 | $44,115 | $44,563 | $45,007 | $45,456 | $45,904 | $46,348 | $46,797 | $47,246 | $47,692 | 542,203 |
| 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) | | 39,188 | 40,144 | 40,559 | 40,976 | 41,392 | 41,805 | 42,222 | 42,638 | 43,050 | 43,467 | 43,884 | 44,299 | 503,625 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $39,188 | $40,144 | $40,559 | $40,976 | $41,392 | $41,805 | $42,222 | $42,638 | $43,050 | $43,467 | $43,884 | $44,299 | $503,625 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
Page 12 of 45

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0154401 Ammonia Inventory | | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | 185,206 |
| | b. 0154200 Limestone Inventory | | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 |
| 2 | Total Working Capital | | $1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 |
| 3 | Average Net Investment | | | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | |
| 4 | Return on Average Net Working Capital Balance (A) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | $21,989 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 90,454 |
| 5 | Total Return Component (B) | | | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 112,443 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0502010 Ammonia Expense | | | 455,485 | 425,538 | 297,964 | 432,747 | 455,824 | 459,359 | 470,739 | 467,246 | 474,561 | 484,937 | 413,592 | 472,009 | 5,310,002 |
| | b. 0502040 Limestone Expense | | | 447,356 | 418,943 | 294,169 | 428,890 | 452,848 | 457,804 | 470,373 | 468,108 | 476,919 | 488,404 | 417,340 | 476,024 | 5,297,179 |
| | c. 0502050 Dibasic Acid Expense | | | 0 | 0 | 22,000 | 0 | 0 | 22,000 | 0 | 22,000 | 0 | 0 | 0 | 22,000 | 88,000 |
| | d. 0502070 Gypsum Disposal/Sale | | | 101,740 | 99,311 | 99,311 | 123,599 | 102,010 | 106,867 | 85,008 | 99,311 | 99,311 | 99,311 | 99,311 | 99,311 | 1,214,400 |
| | e. 0502040 Hydrated Lime Expense | | | 392,243 | 367,696 | 263,483 | 371,906 | 391,298 | 394,918 | 404,935 | 401,472 | 407,628 | 416,522 | 356,548 | 405,595 | 4,574,245 |
| | f. 0502300 Caustic Expense | | | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 300,000 |
| 7 | Net Expense (C) | | | 1,421,824 | 1,336,488 | 1,001,927 | 1,382,142 | 1,426,980 | 1,465,949 | 1,456,055 | 1,483,137 | 1,483,419 | 1,514,175 | 1,311,791 | 1,499,939 | 16,783,826 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | | $1,431,194 | $1,345,858 | $1,011,298 | $1,391,513 | $1,436,350 | $1,475,319 | $1,465,425 | $1,492,507 | $1,492,790 | $1,523,545 | $1,321,161 | $1,509,309 | $16,896,268 |
| | a. Recoverable Costs Allocated to Energy | | | 1,431,194 | 1,345,858 | 1,011,298 | 1,391,513 | 1,436,350 | 1,475,319 | 1,465,425 | 1,492,507 | 1,492,790 | 1,523,545 | 1,321,161 | 1,509,309 | 16,896,268 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | 1,400,082 | 1,314,159 | 994,353 | 1,360,849 | 1,396,157 | 1,431,917 | 1,417,906 | 1,440,318 | 1,442,847 | 1,473,276 | 1,277,119 | 1,474,184 | 16,423,168 |
| 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) | | | $ 1,400,082 | $ 1,314,159 | $ 994,353 | $ 1,360,849 | $ 1,396,157 | $ 1,431,917 | $ 1,417,906 | $ 1,440,318 | $ 1,442,847 | $ 1,473,276 | $ 1,277,119 | $ 1,474,184 | $ 16,423,168 |

Notes:

(A) Line 3 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $150 | $150 | $150 | $150 | $150 | $0 | $0 | $0 | $750 |
| | b. Clearings to Plant | | 300 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 750 | 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 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 12,374 | 12,374 | 12,374 | 12,374 | |
| 3 | Less: Accumulated Depreciation | (2,655) | (2,684) | (2,714) | (2,744) | (2,774) | (2,804) | (2,834) | (2,864) | (2,894) | (2,924) | (2,956) | (2,988) | (3,020) | |
| 4 | CWIP - Non-Interest Bearing | 300 | 0 | 0 | 0 | 0 | 150 | 300 | 450 | 600 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $8,969 | $8,940 | $8,910 | $8,880 | $8,850 | $8,970 | $9,090 | $9,210 | $9,330 | $9,450 | $9,418 | $9,386 | $9,354 | |
| 6 | Average Net Investment | | $8,954 | $8,925 | $8,895 | $8,865 | $8,910 | $9,030 | $9,150 | $9,270 | $9,390 | $9,434 | $9,402 | $9,370 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component 2.03% | | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 16 | 16 | 16 | 16 | 16 | 185 |
| | b. Equity Component Grossed Up For Taxes 8.33% | | 62 | 62 | 62 | 62 | 62 | 63 | 64 | 64 | 65 | 66 | 65 | 65 | 762 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) 3.0658% | | 29 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 32 | 32 | 32 | 365 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/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) 0.009035 | | 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) | | $115 | $116 | $116 | $116 | $116 | $117 | $118 | $119 | $120 | $123 | $122 | $122 | 1,420 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $115 | $116 | $116 | $116 | $116 | $117 | $118 | $119 | $120 | $123 | $122 | $122 | 1,420 |
| 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) | | 114 | 115 | 115 | 115 | 115 | 116 | 117 | 118 | 119 | 122 | 121 | 121 | 1,414 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $114 | $115 | $115 | $115 | $115 | $116 | $117 | $118 | $119 | $122 | $121 | $121 | $1,414 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | (35,344) | (35,640) | (35,936) | (36,232) | (36,528) | (36,824) | (37,120) | (37,416) | (37,712) | (38,008) | (38,304) | (38,600) | (38,896) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $133,597 | $133,301 | $133,005 | $132,709 | $132,413 | $132,117 | $131,821 | $131,525 | $131,229 | $130,933 | $130,637 | $130,341 | $130,045 | |
| 6 | Average Net Investment | | | $133,449 | $133,153 | $132,857 | $132,561 | $132,265 | $131,969 | $131,673 | $131,377 | $131,081 | $130,785 | $130,489 | $130,193 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 225 | 225 | 224 | 224 | 223 | 223 | 222 | 222 | 221 | 221 | 220 | 220 | 2,670 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 927 | 925 | 923 | 921 | 919 | 917 | 915 | 913 | 910 | 908 | 906 | 904 | 10,988 |
| | 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) | | | $1,569 | $1,567 | $1,564 | $1,562 | $1,559 | $1,557 | $1,554 | $1,552 | $1,548 | $1,546 | $1,543 | $1,541 | 18,662 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $1,569 | $1,567 | $1,564 | $1,562 | $1,559 | $1,557 | $1,554 | $1,552 | $1,548 | $1,546 | $1,543 | $1,541 | 18,662 |
| 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) | | | 1,457 | 1,456 | 1,453 | 1,451 | 1,448 | 1,446 | 1,443 | 1,442 | 1,438 | 1,436 | 1,433 | 1,431 | 17,334 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $1,457 | $1,456 | $1,453 | $1,451 | $1,448 | $1,446 | $1,443 | $1,442 | $1,438 | $1,436 | $1,433 | $1,431 | $17,334 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | (21,785) | (21,988) | (22,191) | (22,394) | (22,597) | (22,800) | (23,003) | (23,206) | (23,409) | (23,612) | (23,815) | (24,018) | (24,221) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $54,221 | $54,018 | $53,815 | $53,612 | $53,409 | $53,206 | $53,003 | $52,800 | $52,597 | $52,394 | $52,191 | $51,988 | $51,785 | |
| 6 | Average Net Investment | | | $54,120 | $53,917 | $53,714 | $53,511 | $53,308 | $53,105 | $52,902 | $52,699 | $52,496 | $52,293 | $52,090 | $51,887 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 91 | 91 | 91 | 90 | 90 | 90 | 89 | 89 | 89 | 88 | 88 | 88 | 1,074 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 376 | 374 | 373 | 372 | 370 | 369 | 367 | 366 | 365 | 363 | 362 | 360 | 4,417 |
| | 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) | | | $733 | $731 | $730 | $728 | $726 | $725 | $722 | $721 | $720 | $717 | $716 | $714 | 8,683 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $733 | $731 | $730 | $728 | $726 | $725 | $722 | $721 | $720 | $717 | $716 | $714 | 8,683 |
| 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) | | | 533 | 531 | 531 | 529 | 528 | 527 | 525 | 524 | 523 | 521 | 521 | 519 | 6,313 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $533 | $531 | $531 | $529 | $528 | $527 | $525 | $524 | $523 | $521 | $521 | $519 | $6,313 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | |
| 3 | Less: Accumulated Depreciation | | (431,137) | (467,033) | (502,929) | (538,825) | (574,721) | (610,617) | (646,513) | (682,409) | (718,305) | (754,201) | (790,097) | (825,993) | (861,889) | |
| 4 | CWIP - Non-Interest Bearing | | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $12,463,374 | $12,427,478 | $12,391,582 | $12,355,686 | $12,319,790 | $12,283,894 | $12,247,998 | $12,212,102 | $12,176,206 | $12,140,310 | $12,104,414 | $12,068,518 | $12,032,622 | |
| 6 | Average Net Investment | | | $12,445,426 | $12,409,530 | $12,373,634 | $12,337,738 | $12,301,842 | $12,265,946 | $12,230,050 | $12,194,154 | $12,158,258 | $12,122,362 | $12,086,466 | $12,050,570 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 21,014 | 20,953 | 20,893 | 20,832 | 20,772 | 20,711 | 20,650 | 20,590 | 20,529 | 20,469 | 20,408 | 20,347 | 248,168 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 86,443 | 86,193 | 85,944 | 85,695 | 85,445 | 85,196 | 84,947 | 84,697 | 84,448 | 84,199 | 83,949 | 83,700 | 1,020,856 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.3333% | | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 430,752 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (D) | 0.009890 | | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 127,800 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $154,003 | $153,692 | $153,383 | $153,073 | $152,763 | $152,453 | $152,143 | $151,833 | $151,523 | $151,214 | $150,903 | $150,593 | 1,827,576 |
| | 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 | | | $154,003 | $153,692 | $153,383 | $153,073 | $152,763 | $152,453 | $152,143 | $151,833 | $151,523 | $151,214 | $150,903 | $150,593 | 1,827,576 |
| 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 - 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) | | | 111,965 | 111,739 | 111,514 | 111,289 | 111,063 | 110,838 | 110,613 | 110,387 | 110,162 | 109,937 | 109,711 | 109,486 | 1,328,703 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $111,965 | $111,739 | $111,514 | $111,289 | $111,063 | $110,838 | $110,613 | $110,387 | $110,162 | $109,937 | $109,711 | $109,486 | $1,328,703 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 1
(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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | |
| 3 | Less: Accumulated Depreciation | | (47,336) | (53,873) | (60,411) | (66,948) | (73,486) | (80,023) | (86,561) | (93,098) | (99,636) | (106,173) | (112,710) | (119,248) | (125,785) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $3,617,607 | $3,611,069 | $3,604,532 | $3,597,994 | $3,591,457 | $3,584,919 | $3,578,382 | $3,571,845 | $3,565,307 | $3,558,770 | $3,552,232 | $3,545,695 | $3,539,157 | |
| 6 | Average Net Investment | | | $3,614,338 | $3,607,801 | $3,601,263 | $3,594,726 | $3,588,188 | $3,581,651 | $3,575,113 | $3,568,576 | $3,562,038 | $3,555,501 | $3,548,963 | $3,542,426 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 6,103 | 6,092 | 6,081 | 6,070 | 6,059 | 6,048 | 6,037 | 6,026 | 6,015 | 6,003 | 5,992 | 5,981 | 72,507 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 25,104 | 25,059 | 25,013 | 24,968 | 24,923 | 24,877 | 24,832 | 24,786 | 24,741 | 24,696 | 24,650 | 24,605 | 298,254 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | Blended | | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 78,449 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 6,241 |
| | 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) | | | $37,668 | $37,612 | $37,555 | $37,499 | $37,443 | $37,386 | $37,330 | $37,273 | $37,217 | $37,160 | $37,103 | $37,047 | 448,291 |
| | a. Recoverable Costs Allocated to Energy | | | 37,668 | 37,612 | 37,555 | 37,499 | 37,443 | 37,386 | 37,330 | 37,273 | 37,217 | 37,160 | 37,103 | 37,047 | 448,291 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $36,849 | $36,726 | $36,926 | $36,673 | $36,395 | $36,286 | $36,119 | $35,970 | $35,972 | $35,934 | $35,866 | $36,185 | $435,901 |
| 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) | | | $36,849 | $36,726 | $36,926 | $36,673 | $36,395 | $36,286 | $36,119 | $35,970 | $35,972 | $35,934 | $35,866 | $36,185 | $435,901 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | |
| 3 | Less: Accumulated Depreciation | | (5,824,679) | (6,068,599) | (6,312,519) | (6,556,439) | (6,800,359) | (7,044,279) | (7,288,199) | (7,532,119) | (7,776,039) | (8,019,959) | (8,263,879) | (8,507,799) | (8,751,719) | |
| 4 | CWIP - AFUDC Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $128,925,596 | $128,681,676 | $128,437,756 | $128,193,836 | $127,949,916 | $127,705,996 | $127,462,076 | $127,218,156 | $126,974,236 | $126,730,316 | $126,486,396 | $126,242,476 | $125,998,556 | |
| 6 | Average Net Investment | | | $128,803,636 | $128,559,716 | $128,315,796 | $128,071,876 | $127,827,956 | $127,584,036 | $127,340,116 | $127,096,196 | $126,852,276 | $126,608,356 | $126,364,436 | $126,120,516 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 217,485 | 217,073 | 216,661 | 216,249 | 215,838 | 215,426 | 215,014 | 214,602 | 214,190 | 213,778 | 213,366 | 212,954 | 2,582,636 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 894,636 | 892,941 | 891,247 | 889,553 | 887,859 | 886,165 | 884,470 | 882,776 | 881,082 | 879,388 | 877,694 | 875,999 | 10,623,810 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.1722% | | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 2,927,040 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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) | 0.007910 | | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 1,065,876 |
| | 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) | | | $1,430,070 | $1,427,963 | $1,425,857 | $1,423,751 | $1,421,646 | $1,419,540 | $1,417,433 | $1,415,327 | $1,413,221 | $1,411,115 | $1,409,009 | $1,406,902 | 17,021,828 |
| | a. Recoverable Costs Allocated to Energy | | | 1,430,070 | 1,427,963 | 1,425,857 | 1,423,751 | 1,421,646 | 1,419,540 | 1,417,433 | 1,415,327 | 1,413,221 | 1,411,115 | 1,409,009 | 1,406,902 | 17,021,828 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $1,398,982 | $1,394,329 | $1,401,967 | $1,392,377 | $1,381,864 | $1,377,778 | $1,371,470 | $1,365,837 | $1,365,940 | $1,364,555 | $1,362,038 | $1,374,159 | $16,551,296 |
| 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) | | | $1,398,982 | $1,394,329 | $1,401,967 | $1,392,377 | $1,381,864 | $1,377,778 | $1,371,470 | $1,365,837 | $1,365,940 | $1,364,555 | $1,362,038 | $1,374,159 | $16,551,296 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $600,000 | $600,000 | $1,000,000 | $300,000 | $100,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,600,000 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 4,965,495 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | (194,715) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $20,070,225 | 20,070,225 | 20,070,225 | 20,070,225 | 20,070,225 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | |
| 3 | Less: Accumulated Depreciation | | (491,482) | (553,365) | (615,248) | (677,131) | (739,014) | (800,897) | (878,090) | (955,283) | (1,032,476) | (1,109,669) | (1,186,862) | (1,264,055) | (1,341,248) | |
| 4 | CWIP - Non-Interest Bearing | | 2,560,209 | 2,965,495 | 3,565,495 | 4,565,495 | 4,865,495 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $22,138,952 | $22,482,354 | $23,020,471 | $23,958,588 | $24,196,705 | $24,234,822 | $24,157,629 | $24,080,436 | $24,003,243 | $23,926,050 | $23,848,857 | $23,771,664 | $23,694,471 | |
| 6 | Average Net Investment | | | $22,310,653 | $22,751,413 | $23,489,530 | $24,077,647 | $24,215,764 | $24,196,226 | $24,119,033 | $24,041,840 | $23,964,647 | $23,887,454 | $23,810,261 | $23,733,068 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 37,672 | 38,416 | 39,662 | 40,655 | 40,888 | 40,855 | 40,725 | 40,595 | 40,464 | 40,334 | 40,204 | 40,073 | 480,543 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 154,964 | 158,025 | 163,152 | 167,237 | 168,196 | 168,061 | 167,524 | 166,988 | 166,452 | 165,916 | 165,380 | 164,844 | 1,976,739 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.7000% | | 61,883 | 61,883 | 61,883 | 61,883 | 61,883 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 849,766 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | | 2,848 | 2,848 | 2,848 | 2,848 | 2,848 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 39,111 |
| | 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) | | | $246,827 | $250,632 | $257,005 | $262,083 | $263,275 | $279,122 | $278,455 | $277,789 | $277,122 | $276,456 | $275,790 | $275,123 | 3,219,684 |
| | a. Recoverable Costs Allocated to Energy | | | 246,827 | 250,632 | 257,005 | 262,083 | 263,275 | 279,122 | 278,455 | 277,789 | 277,122 | 276,456 | 275,790 | 275,123 | 3,219,684 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $241,462 | $244,729 | $252,699 | $256,308 | $255,908 | $270,911 | $269,426 | $268,076 | $267,851 | $267,335 | $266,597 | $268,720 | $3,130,022 |
| 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) | | | $241,462 | $244,729 | $252,699 | $256,308 | $255,908 | $270,911 | $269,426 | $268,076 | $267,851 | $267,335 | $266,597 | $268,720 | $3,130,022 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

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Duke Energy Florida, LLC
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Return on Capital Investments, Depreciation and Taxes**
**For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Energy (Project 18)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $150,000 | $150,000 | $3,858,000 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,058,000 | 0 | 1,800,000 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | (1,600,000) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $1,600,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,058,000 | 2,058,000 | 3,858,000 | |
| 3 | Less: Accumulated Depreciation (A) | | (7,204) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (4,236) | (8,472) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 355,800 | 711,600 | 1,067,400 | 1,423,200 | 1,779,000 | 2,134,800 | 2,490,600 | 2,846,400 | 3,202,200 | 1,500,000 | 1,650,000 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $1,592,796 | $355,800 | $711,600 | $1,067,400 | $1,423,200 | $1,779,000 | $2,134,800 | $2,490,600 | $2,846,400 | $3,202,200 | $3,558,000 | $3,703,764 | $3,849,528 | |
| 6 | Average Net Investment | | | $974,298 | $533,700 | $889,500 | $1,245,300 | $1,601,100 | $1,956,900 | $2,312,700 | $2,668,500 | $3,024,300 | $3,380,100 | $3,630,882 | $3,776,646 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 1,645 | 901 | 1,502 | 2,103 | 2,703 | 3,304 | 3,905 | 4,506 | 5,107 | 5,707 | 6,131 | 6,377 | 43,891 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 6,767 | 3,707 | 6,178 | 8,650 | 11,121 | 13,592 | 16,063 | 18,535 | 21,006 | 23,477 | 25,219 | 26,232 | 180,547 |
| | c. Other (A) | | | (56,879) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (56,879) |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.4700% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4,236 | 4,236 | 8,472 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | 292 | 292 | 584 |
| | e. Other (A) | | | (7,700) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (7,700) |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | ($56,167) | $4,608 | $7,680 | $10,753 | $13,824 | $16,896 | $19,968 | $23,041 | $26,113 | $29,184 | $35,878 | $37,137 | 168,915 | |
| | a. Recoverable Costs Allocated to Energy | | (56,167) | 4,608 | 7,680 | 10,753 | 13,824 | 16,896 | 19,968 | 23,041 | 26,113 | 29,184 | 35,878 | 37,137 | 168,915 | |
| | b. Recoverable Costs Allocated to Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | | |
| 11 | Demand Jurisdictional Factor | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | ($54,946) | $4,499 | $7,551 | $10,516 | $13,437 | $16,399 | $19,321 | $22,235 | $25,239 | $28,221 | $34,682 | $36,273 | $163,427 | |
| 13 | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | ($54,946) | $4,499 | $7,551 | $10,516 | $13,437 | $16,399 | $19,321 | $22,235 | $25,239 | $28,221 | $34,682 | $36,273 | $163,427 | |

Notes:

(A) As explained in the testimony of Garry Miller, DEF has revised the permanent dust mitigation in-service date from October 2015 to October 2016 and determined vegetation management compliance can be achived without the 2015 capital investment. As a result, DEF has made these adjustments to ensure that the revenue requirement impact to customers is neutral.
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2nd Qtr end 2015, a total of 260 substation remediations are completed out of 279 slated for clean-up. DEF expects to remediate 3 more substations during the remainder of 2015.

**Project Fiscal Expenditures:**
2015 expenditures are estimated to be $405k lower than originally projected due to remediation work delays at the Consolidated Rock, Holder and Kenneth City substations.

**Project Progress Summary:**
DEF continues to remediate substation sites in accordance with the approved Substation Assessment and Remedial Action Plan (SARAP).

**Project Projections:**
2016 estimated expenditures are $1.1M.

**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:**
As of 2nd Qtr end 2015, there are 3 remaining Transformer Replacement and Inspection Program (TRIP) sites.

**Project Fiscal Expenditures:**
2015 expenditures are estimated to be $42k higher than originally projected due to costs to remove additional impacted soil at the three remaining sites.

**Project Progress Summary:**
This project is on schedule according to the approved Distribution System Investigation, Remediation and Pollution Prevention Program.

**Project Projections:**
2016 estimated expenditures are $3k.

**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) contains 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.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $19k higher than originally projected due to increased costs to comply with PIM regulations. No capital expenditures are estimated for 2015.

**Project Progress Summary:**
Ongoing regulatory compliance activities will continue until pipeline is sold or retired.

**Project Projections:**
2016 estimated O&M expenditures are $696k. No capital expenditures are expected in 2016.

**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 2015.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

**Project Projections:**
No project expenditures are expected in 2016.

**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 is treating its unused NOx costs as a regulatory asset amortizing it over 3 years, as approved by the Commission in Order No. PSC-11-0553-FOF-EI.

**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:**
2015 emission allowance expenditures are estimated to be $1.5M higher than originally projected due to unusable NOx emission allowances as a result of the expiration of the CAIR. CAIR was replaced by the CSAPR on 1/1/15. Consistent with Order No. PSC-11-0553-FOF-EI, DEF is treating costs associated with its unusable CAIR NOx emission allowances as a regulatory asset amortizing it over 3 years, beginning 1/1/15 until fully recovered by 12/31/17, with a return on the unamortized investment.

**Project Progress Summary:**
DEF continually evaluates the status of emission rules to maximize the cost effectiveness of its compliance strategy.

**Project Projections:**
2016 estimated expenditures are $111k. 2016 amortization of the CAIR NOx regulatory asset is approximately $3.6M.

**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.

**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 are under development to ensure compliance with all applicable requirements of the rule.

**Project Fiscal Expenditures:**
2015 project expenditures are estimated to be $43k lower than originally projected as methods used to allocate costs to analyze 316(b) compliance strategies at each affected Duke Energy station were adjusted to reflect present configurations and operations. DEF intends to implement a consistent approach across its entire fleet of regulated units to focus on full compliance with applicable 316(b) requirements through the development of facility specific strategic plans.

**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.

**Project Projections:**
2016 estimated O&M expenditures are $440k. No capital expenditures are expected in 2016.

**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 not 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)

**Project Accomplishments:**
The reclaimed water reuse system project was placed in-service in July 2015. This project will provide DEF with up to 1 1/2 million gallons per day of reclaimed water from the City of Crystal River to supplement well water use. This project has positive environmental impacts as it reduces aquifer use.

**Project Fiscal Expenditures:**
2015 estimated O&M expenditures are estimated to be $661k higher than originally projected due to a $710 decrease in CAIR Crystal River Project 7.4 - Base costs and $1.4 million increase in CAIR Crystal River Project 7.4 - Energy costs. The $710k is due to lower base routine project costs. The $1.4M is due to higher ammonia and hydrated lime costs offset by lower limestone and gypsum costs. 2015 estimated capital expenditures are expected to be $124k higher than originally projected due to a shift in spending from 2014 to 2015 in order to align with the City of Crystal River reclaimed water reuse project timeline.

**Project Progress Summary:**
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program.

**Project Projections:**
2016 estimated O&M and capital expenditures are $34.4M and $713k, 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 2015.

**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 2016.

**Project Title:** **Arsenic Groundwater Standard**
**Project No. 8**

**Project Description:**
On 1/22/01, the EPA adopted a new maximum contaminant level (MCL) for arsenic in drinking water replacing the previous standard of 0.050 mg/L (50ppb) with a new MCL of 0.010 mg/L (10ppb). 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 implications for land application and water reuse projects in Florida because the drinking water standard has been established as the groundwater standard by Rule 62-520.420(1), F.A.C. Lowering the arsenic standard will require new analytical methods for sampling groundwater at numerous DEF sites.

**Project Accomplishments:**
DEF has completed required monitoring as directed by the FDEP.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $23k higher than originally projected due to consultant costs to evaluate the source of arsenic exceedances and issue a summery report in compliance with FDEP Consent Order No. 09-3463C executed on 11/21/11. The Consent Order was issued by the FDEP for exceedance of the arsenic groundwater limit when the EPA lowered the arsenic maximum containment level from 50ppb to 10 ppb.

**Project Progress Summary:**
DEF is evaluating monitoring data and other options to achieve compliance in accordance to Consent Order.

**Project Projections:**
No project expenditures are expected in 2016.

**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:**
2015 capital expenditures are estimated to be $3k lower than originally projected. No new street lighting has been required in Franklin County, the City of Mexico Beach in Bay county or GULF County as DEF is in compliance with sea turtle ordinances. Also, the Don Cesar lighting project is delayed from 2014 to late 4th quarter 2015 due to scheduling conflicts.

**Project Progress Summary:**
DEF is on schedule with activities identified for this program.

**Project Projections:**
2016 estimated project O&M and capital expenditures are $450 and $750, 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

**Project Projections:**
No 2016 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 2015 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 2016 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. 060162-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 2015 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 180MWe 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 2016 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 2015 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 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
The mercury TMDL study concluded in 2012.

**Project Projections:**
No 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA during 2010.

**Project Projections:**
No 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA in September 2010.

**Project Projections:**
No 2016 expenditures are expected for this project.

**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 1/14/11, 2/14/11, 7/18/11,4/7/14 and 11/28/11, respectively. All facilities are required to meet new permitting conditions. In Docket No. 110007-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 thermal studies and whole effluent toxicity testing as required 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.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $54k lower than originally projected due to lower than expected 316(a) thermal study costs at the Anclote and Bartow stations. 2015 capital expenditures are expected to be $86k lower than originally projected due to a vendor reimbursement payment.

**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. DEF continues to work with FDEP to resolve the copper issue at the Suwannee station.

**Project Projections:**
2016 estimated O&M expenditures are $60k. No capital expenditures are expected in 2016.

**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-11-0553-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 the existing FGD and SCR systems as the primary MATS compliance measures. Additional monitoring and emissions reduction technologies will be installed in 2014 & 2015.

**Project Accomplishments:**
DEF installed ORP probes and particulate matter continuous emissions monitoring systems (PM CEMS) in 2014. In addition, a mercury characterization study was performed in late 2014, and temporary mercury re-emission control systems were installed in early 2015. DEF continues to monitor mercury emissions with Appendix K sorbent trap systems.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $153k higher than originally projected due to the addition of a temporary chemical injection system to control mercury emissions, and the cancellation of preliminary engineering for a fuel additive system to improve mercury oxidation. 2015 capital expenditures are expected to be $1.3M higher than originally projected driven by the installation of continuous emission monitoring systems (CEMS) for mercury monitoring, compliance demonstration and feedback to the re-emission control system.

**Project Progress Summary:**
Installation of mercury CEMS and permanent mercury re-emission control systems is scheduled in the third quarter of 2015. Certification and commissioning activities are expected to be completed by the end of the year.

**Project Projections:**
2016 estimated O&M is $529k. No capital expenditures are expected in 2016.

**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-12-0432-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:**
2015 capital expenditures are estimated to be $314k lower than originally projected due to earlier than expected completion of Unit 2 FD fan work in November 2013 versus December 2014. There are no recoverable O&M costs for this project.

**Project Progress Summary:**
This project is in-service.

**Project Projections:**
No 2016 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-14-0173-PAA-EI. DEF will make modifications to the electrostatic precipitators to improve particulate collection efficiency, as well as install reagent injection systems to reduce HCl and mercury emissions.

**Project Accomplishments:**
DEF finalized its CR1&2 MATS Compliance Plan in December 2013 and began implementation in early 2014.

**Project Fiscal Expenditures:**
2015 O&M expenditures are expected to be $51k lower than expected. Capital expenditures are estimated to be $4.2M higher than originally projected due to an additional project related to the Unit 1 electrostatic precipitator (ESP).

**Project Progress Summary:**
Implementation of the CR1&2 MATS Compliance Plan will be completed by April 2016.

**Project Projections:**
2016 estimated O&M and capital expenditures are $3.8M and $2.6M, respectively.

**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:**
DEF began defining and implementing of its CCR Rule compliance strategy.

**Project Fiscal Expenditures:**
2015 estimated O&M and capital expenditures are $391k and $1.6M, respectively.

**Project Progress Summary:**
Ash Landfill: Two engineering firms are studying Crystal River ash landfill stability and ash placement.
Temporary Gypsum Pad: Efforts are underway to address fugitive dust mitigation at the CCR gypsum stack-out.
FGD Blowdown Ponds: A definitive assessment and action plan is being developed.
Emergency Action Plan: A determination if the CCR requires an EPA for the FGD Blowdown Ponds is in process.
Vegetation Mgt & Inspection Work: More frequent mowing and inspection work is planned to comply with the CCR Rule.

**Project Projections:**
2016 estimated O&M and capital expenditures are $1.8M and $3.9M, respectively. See the August 31, 2015 direct testimony of Mr. Miller for 2015 CCR compliance strategy change.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of the Energy & Demand Allocation % by Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) Average 12CP Load Factor at Meter (%) | (2) Sales at Meter (mWh) | (3) Avg 12 CP at Meter (MW) (2)/(8784hrsx(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)/(8784hrs/(4)) | (9) mWh Sales at Source Energy Allocator (%) | (10) 12CP Demand Transmission Allocator (%) | (11) 12CP & 1/13 AD Demand Allocator (%) | (12) NCP Distribution Allocator (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | | | | | |
| **RS-1, RST-1, RSL-1, RSL-2, RSS-1** | | | | | | | | | | | | | |
| Secondary | 0.518 | 19,482,925 | 4,282.48 | 0.401 | 0.9463589 | 20,587,248 | 4,525.22 | 20,587,248 | 5,851.4 | 51.568% | 61.617% | 60.844% | 61.780% |
| **General Service Non-Demand** | | | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | | | |
| Secondary | 0.682 | 1,547,422 | 258.45 | 0.491 | 0.9463589 | 1,635,132 | 273.10 | 1,635,132 | 378.9 | 4.096% | 3.719% | 3.748% | 4.000% |
| Primary | 0.682 | 8,546 | 1.43 | 0.491 | 0.9766343 | 8,750 | 1.46 | 8,750 | 2.0 | 0.022% | 0.020% | 0.020% | 0.021% |
| Transmission | 0.682 | 3,571 | 0.60 | 0.491 | 0.9866343 | 3,619 | 0.60 | 0 | 0.0 | 0.009% | 0.008% | 0.008% | 0.000% |
| | | | | | | | | | | 4.127% | 3.747% | 3.776% | 4.021% |
| **General Service** | | | | | | | | | | | | | |
| **GS-2** Secondary | 1.000 | 161,981 | 18.44 | 1.000 | 0.9463589 | 171,162 | 19.49 | 171,162 | 19.5 | 0.429% | 0.265% | 0.278% | 0.206% |
| **General Service Demand** | | | | | | | | | | | | | |
| **GSD-1, GSDT-1** | | | | | | | | | | | | | |
| Secondary | 0.749 | 11,824,122 | 1,797.93 | 0.594 | 0.9463589 | 12,494,332 | 1,899.84 | 12,494,332 | 2,394.0 | 31.296% | 25.869% | 26.286% | 25.277% |
| Primary | 0.749 | 2,313,813 | 351.83 | 0.594 | 0.9766343 | 2,369,170 | 360.25 | 2,369,170 | 454.0 | 5.934% | 4.905% | 4.984% | 4.793% |
| Secondary Del/ Primary Mtr | 0.749 | 46,245 | 7.03 | 0.594 | 0.9766343 | 47,351 | 7.20 | 47,351 | 9.1 | 0.119% | 0.098% | 0.100% | 0.096% |
| Transm Del/ Primary Mtr | 0.749 | 1,419 | 0.22 | 0.594 | 0.9766343 | 1,453 | 0.22 | 0 | 0.0 | 0.004% | 0.003% | 0.003% | 0.000% |
| Transmission | 0.749 | 0 | 0.00 | 0.594 | 0.9866343 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| **SS-1** Primary | 1.166 | 5,602 | 0.55 | 0.093 | 0.9766343 | 5,736 | 0.56 | 5,736 | 7.0 | 0.014% | 0.008% | 0.008% | 0.074% |
| Transm Del/ Transm Mtr | 1.166 | 11,127 | 1.09 | 0.093 | 0.9866343 | 11,278 | 1.10 | 0 | 0.0 | 0.028% | 0.015% | 0.016% | 0.000% |
| Transm Del/ Primary Mtr | 1.166 | 3,474 | 0.34 | 0.093 | 0.9766343 | 3,557 | 0.35 | 0 | 0.0 | 0.009% | 0.005% | 0.005% | 0.000% |
| | | | | | | | | | | 37.404% | 30.902% | 31.403% | 30.240% |
| **Curtailable** | | | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, SS-3** | | | | | | | | | | | | | |
| Secondary | 1.305 | 0 | 0.00 | 0.456 | 0.9463589 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| Primary | 1.305 | 121,852 | 10.63 | 0.456 | 0.9766343 | 124,767 | 10.88 | 124,767 | 31.2 | 0.313% | 0.148% | 0.161% | 0.329% |
| **SS-3** Primary | 0.583 | 3,604 | 0.70 | 0.077 | 0.9766343 | 3,690 | 0.72 | 3,690 | 5.5 | 0.009% | 0.010% | 0.010% | 0.058% |
| | | | | | | | | | | 0.322% | 0.158% | 0.171% | 0.387% |
| **Interruptible** | | | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2** | | | | | | | | | | | | | |
| Secondary | 1.009 | 88,539 | 9.99 | 0.707 | 0.9463589 | 93,558 | 10.55 | 93,558 | 15.1 | 0.234% | 0.144% | 0.151% | 0.159% |
| Sec Del/Primary Mtr | 1.009 | 4,449 | 0.50 | 0.707 | 0.9766343 | 4,555 | 0.51 | 4,555 | 0.7 | 0.011% | 0.007% | 0.007% | 0.008% |
| Primary Del / Primary Mtr | 1.009 | 1,229,525 | 138.66 | 0.707 | 0.9766343 | 1,258,941 | 141.98 | 1,258,941 | 202.9 | 3.153% | 1.933% | 2.027% | 2.142% |
| Primary Del / Transm Mtr | 1.009 | 9,117 | 1.03 | 0.707 | 0.9866343 | 9,241 | 1.04 | 9,241 | 1.5 | 0.023% | 0.014% | 0.015% | 0.016% |
| Transm Del/ Transm Mtr | 1.009 | 222,224 | 25.06 | 0.707 | 0.9866343 | 225,234 | 25.40 | 0 | 0.0 | 0.564% | 0.346% | 0.363% | 0.000% |
| Transm Del/ Primary Mtr | 1.009 | 269,448 | 30.39 | 0.707 | 0.9766343 | 275,894 | 31.11 | 0 | 0.0 | 0.691% | 0.424% | 0.444% | 0.000% |
| **SS-2** Primary | 0.870 | 9,262 | 1.21 | 0.380 | 0.9766343 | 9,484 | 1.24 | 9,484 | 2.8 | 0.024% | 0.017% | 0.017% | 0.030% |
| Transm Del/ Transm Mtr | 0.870 | 92,038 | 12.05 | 0.380 | 0.9866343 | 93,285 | 12.21 | 0 | 0.0 | 0.234% | 0.166% | 0.171% | 0.000% |
| Transm Del/ Primary Mtr | 0.870 | 80,335 | 10.52 | 0.380 | 0.9766343 | 82,257 | 10.77 | 0 | 0.0 | 0.206% | 0.147% | 0.151% | 0.000% |
| | | | | | | | | | | 5.141% | 3.197% | 3.347% | 2.354% |
| **Lighting** | | | | | | | | | | | | | |
| **LS-1** (Secondary) | 5.506 | 381,551 | 7.89 | 0.479 | 0.9463589 | 403,178 | 8.34 | 403,178 | 95.8 | 1.010% | 0.114% | 0.182% | 1.012% |
| | | 37,922,191 | 6,969.01 | | | 39,922,874 | 7,344.16 | 39,226,296 | 9,471.2 | 100.000% | 100.000% | 100.000% | 100.000% |

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2015
(2) Projected kWh sales for the period January 2016 to December 2016
(3) Calculated: Column 2 / (8,784 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2015
(5) Based on system average line loss analysis for 2014
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,784 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 9 x 1/13 + Column 10 x 12/13
(12) Column 8/ Total Column 8

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) mWh Sales at Source Energy Allocator (%) | (2) 12CP Transmission Demand Allocator (%) | (3) 12CP & 1/13th AD Demand Allocator (%) | (4) NCP Distribution Allocator (%) | (5) Energy-Related Costs ($) | (6) Transmission Demand Costs ($) | (8) Production Demand Costs ($) | (7) Distribution Demand Costs ($) | (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 | 51.568% | 61.617% | 60.844% | 61.780% | $33,378,628 | $480,062 | $2,168,692 | ($164,617) | $35,862,765 | 19,482,925 | **0.184** |
| **General Service Non-Demand** | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 1,547,422 | **0.181** |
| Primary | | | | | | | | | | 8,461 | **0.179** |
| Transmission | | | | | | | | | | 3,500 | **0.177** |
| **TOTAL GS** | 4.127% | 3.747% | 3.776% | 4.021% | $2,671,137 | $29,191 | $134,590 | ($10,715) | $2,824,203 | **1,559,382** | |
| **General Service** | | | | | | | | | | | |
| **GS-2** Secondary | 0.429% | 0.265% | 0.278% | 0.206% | $277,510 | $2,067 | $9,905.12 | ($548.19) | $288,934 | 161,981 | **0.178** |
| **General Service Demand** | | | | | | | | | | | |
| **GSD-1, GSDT-1, SS-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 11,824,122 | **0.180** |
| Primary | | | | | | | | | | 2,346,847 | **0.178** |
| Transmission | | | | | | | | | | 10,904 | **0.176** |
| **TOTAL GSD** | 37.404% | 30.902% | 31.403% | 30.240% | $24,211,054 | $240,764 | $1,119,303 | ($80,575) | $25,490,546 | **14,181,874** | |
| **Curtailable** | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3** | | | | | | | | | | | |
| Secondary | | | | | | | | | | - | **0.173** |
| Primary | | | | | | | | | | 124,201 | **0.171** |
| Transmission | | | | | | | | | | - | **0.170** |
| **TOTAL CS** | 0.322% | 0.158% | 0.171% | 0.387% | $208,271 | $1,231 | $6,081 | ($1,030) | $214,553 | **124,201** | |
| **Interruptible** | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2, SS-2** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 88,539 | **0.175** |
| Primary | | | | | | | | | | 1,577,089 | **0.173** |
| Transmission | | | | | | | | | | 316,911 | **0.172** |
| **TOTAL IS** | 5.141% | 3.197% | 3.347% | 2.354% | $3,327,687 | $24,912 | $119,299 | ($6,274) | $3,465,624 | **1,982,539** | |
| **Lighting** | | | | | | | | | | | |
| **LS-1** Secondary | 1.010% | 0.114% | 0.182% | 1.012% | $653,683 | $884 | $6,503.57 | ($2,695.78) | $658,375 | 381,551 | **0.173** |
| | 100.000% | 100.000% | 100.000% | 100.000% | $64,727,970 | $779,111 | $3,564,373 | ($266,454) | $68,805,000 | 37,874,454 | **0.182** |

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 4 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
(8) Column 3 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 2016 to December 2016
(11) (Column 9/ Column 10)/10

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

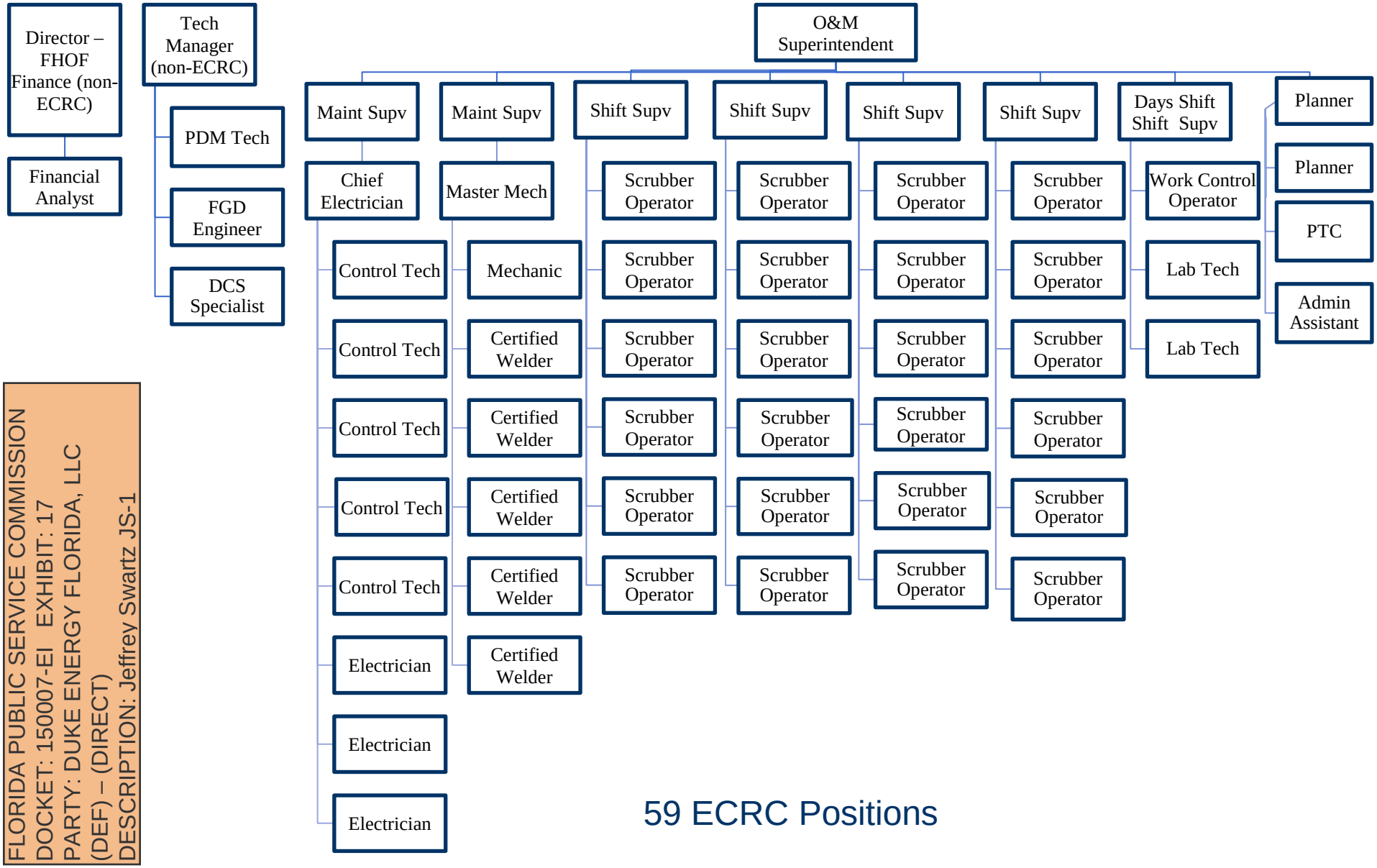
**Capital Structure and Cost Rates**



| Class of Capital | | Retail Amount | Ratio | Cost Rate | Weighted Cost Rate | PreTax Weighted Cost Rate |
|---|---|---|---|---|---|---|
| CE | $ | 4,681,853 | 48.76% | 0.10500 | 5.120% | 8.335% |
| PS | | - | 0.00% | 0.00000 | 0.000% | 0.000% |
| LTD | | 3,672,596 | 38.25% | 0.05187 | 1.984% | 1.984% |
| STD | | (90,568) | -0.94% | 0.00170 | -0.002% | -0.002% |
| CD-Active | | 182,163 | 1.90% | 0.02306 | 0.044% | 0.044% |
| CD-Inactive | | 1,306 | 0.01% | 0.00000 | 0.000% | 0.000% |
| ADIT | | 1,318,615 | 13.73% | 0.00000 | 0.000% | 0.000% |
| FAS 109 | | (164,391) | -1.71% | 0.00000 | 0.000% | 0.000% |
| ITC | | 498 | 0.01% | 0.00000 | 0.000% | 0.000% |
| Total | $ | 9,602,073 | 100.00% | | 7.146% | 10.361% |
| | | | | Total Debt | 2.026% | 2.026% |
| | | | | Total Equity | 5.120% | 8.335% |

May 2015 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

Witness: J. Swartz
Exhibit_(JS-1)
8-5-15




FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 17
PARTY: DUKE ENERGY FLORIDA, LLC
(DEF) – (DIRECT)
DESCRIPTION: Jeffrey Swartz JS-1

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Commission Forms 42-1P Through 42-8P**

**January 2016 - December 2016**
**Calculation of Projected Period Amount**

**Docket No. 150007-EI**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 18
PARTY: DUKE ENERGY FLORIDA, LLC
(DEF) – (DIRECT)
DESCRIPTION: Jeffrey Swartz TGF-5

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

| 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) | $42,339,858 | $329,256 | $621,710 | $876,120 | $44,166,944 |
| b | Projected Capital Projects (Form 42-3P, Lines 7 through 9) | 22,049,877 | 0 | 1,414 | 3,176,702 | 25,227,993 |
| c | Total Jurisdictional Rev Req for the Projected Period (Lines 1a + 1b) | 64,389,735 | 329,256 | 623,124 | 4,052,822 | 69,394,937 |
| 2 | True-up for Estimated Over/(Under) Recovery for the Current Period January 2015 - December 2015 (Form 42-2E, Line 5 + 6 + 10) | (1,720,135) | (350,923) | 885,148 | 406,308 | (779,602) |
| 3 | Final True-up for the Period January 2014 - December 2014 (Form 42-1A, Line 3) | 1,428,470 | (98,371) | 4,238 | 84,706 | 1,419,043 |
| 4 | Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection Period January 2016 - December 2016 (Line 1 - Line 2 - Line 3) | 64,681,400 | 778,551 | (266,263) | 3,561,808 | 68,755,496 |
| 5 | Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072) | $64,727,970 | $779,111 | ($266,454) | $3,564,373 | $68,805,000 |

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**O&M Activities**
**(in Dollars)**

Form 42-2P

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)


| Line | Description | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | O&M Activities - System | | | | | | | | | | | | | |
| 1 | Transmission Substation Environmental Investigation, Remediation and Pollution Prevention | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $469,000 |
| 1a | Distribution Substation Environmental Investigation, Remediation and Pollution Prevention | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 621,000 |
| 2 | Distribution System Environmental Investigation, Remediation and Pollution Prevention | 3,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,000 |
| 3 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 51,723 | 51,723 | 51,723 | 51,723 | 695,676 |
| 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 | 8,824 | 8,824 | 10,978 | 8,657 | 9,562 | 9,661 | 9,921 | 9,934 | 9,931 | 8,793 | 7,740 | 8,223 | 111,050 |
| 5 | NOx Emissions Allowances Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 6 | Phase II Cooling Water Intake 316(b) - Base | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 250,000 |
| 6a | Phase II Cooling Water Intake 316(b) - Intm | 20,500 | 20,500 | 20,500 | 20,500 | 20,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 190,000 |
| 7.2 | CAIR/CAMR - Peaking | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 31,850 | 0 | 66,109 | 0 | 134,459 |
| 7.4 | CAIR/CAMR Crystal River - Base | 1,119,721 | 3,452,919 | 1,914,869 | 1,317,818 | 1,346,472 | 1,114,151 | 1,120,802 | 1,088,803 | 1,326,571 | 1,200,915 | 1,221,061 | 1,105,970 | 17,330,071 |
| 7.4 | CAIR/CAMR Crystal River - Energy | 1,421,824 | 1,336,488 | 1,001,927 | 1,382,142 | 1,426,980 | 1,465,949 | 1,456,055 | 1,483,137 | 1,483,419 | 1,514,175 | 1,311,791 | 1,499,939 | 16,783,826 |
| 7.4 | CAIR/CAMR Crystal River - A&G | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 141,192 |
| 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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Sea Turtle - Coastal Street Lighting - Distrib | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 50 | 50 | 50 | 0 | 0 | 450 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Energy | 0 | 0 | 18,232 | 0 | 4,290 | 7,500 | 0 | 0 | 18,232 | 0 | 4,290 | 7,500 | 60,044 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 48,283 | 48,283 | 43,283 | 43,283 | 529,400 |
| 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 | 266,003 | 266,003 | 406,003 | 542,253 | 366,003 | 266,003 | 302,253 | 266,003 | 266,003 | 302,253 | 266,003 | 266,003 | 3,780,792 |
| 18 | Coal Combustion Residual (CCR) Rule - Energy (C) | 150,333 | 75,333 | 75,333 | 294,083 | 294,083 | 294,083 | 294,083 | 75,333 | 75,333 | 75,333 | 50,333 | 50,333 | 1,804,000 |
| 2 | Total O&M Activities - Recoverable Costs | $3,512,115 | $5,718,478 | $3,994,753 | $4,087,364 | $3,989,901 | $3,716,858 | $3,717,624 | $3,457,671 | $3,766,426 | $3,631,555 | $3,452,362 | $3,488,005 | $46,533,115 |
| 3 | Recoverable Costs Allocated to Energy | 1,890,267 | 1,729,932 | 1,555,758 | 2,270,419 | 2,144,202 | 2,086,481 | 2,105,596 | 1,877,691 | 1,901,203 | 1,948,838 | 1,683,441 | 1,875,283 | 23,069,111 |
| | Recoverable Costs Allocated to Energy - NOx Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 4 | Recoverable Costs Allocated to Demand - Transm | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 469,000 |
| | Recoverable Costs Allocated to Demand - Distrib | 54,750 | 51,750 | 51,750 | 51,750 | 51,850 | 51,850 | 51,850 | 51,800 | 51,800 | 51,800 | 51,750 | 51,750 | 624,450 |
| | Recoverable Costs Allocated to Demand - Prod-Base | 1,132,221 | 3,465,419 | 1,952,369 | 1,330,318 | 1,358,972 | 1,151,651 | 1,133,302 | 1,101,303 | 1,364,071 | 1,213,415 | 1,233,561 | 1,143,470 | 17,580,071 |
| | Recoverable Costs Allocated to Demand - Prod-Intm | 81,598 | 81,598 | 81,598 | 81,598 | 81,598 | 73,598 | 73,598 | 73,598 | 64,223 | 64,223 | 64,223 | 64,223 | 885,676 |
| | Recoverable Costs Allocated to Demand - Prod-Peaking | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 31,850 | 0 | 66,109 | 0 | 134,459 |
| | Recoverable Costs Allocated to Demand - A&G | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 141,192 |
| 5 | Retail Energy Jurisdictional Factor | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | 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) | 1,849,176 | 1,689,187 | 1,529,691 | 2,220,389 | 2,084,201 | 2,025,099 | 2,037,318 | 1,812,034 | 1,837,596 | 1,884,537 | 1,627,322 | 1,831,640 | 22,428,190 |
| | Retail Energy Jurisdictional Factor - NOx Regulatory Asset (A) | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 8 | Jurisdictional Demand Recoverable Costs - Transm (B) | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 329,256 |
| | Jurisdictional Demand Recoverable Costs - Distrib (B) | 54,510 | 51,523 | 51,523 | 51,523 | 51,622 | 51,622 | 51,622 | 51,573 | 51,573 | 51,573 | 51,523 | 51,523 | 621,710 |
| | Jurisdictional Demand Recoverable Costs - Prod-Base (B) | 1,051,663 | 3,218,854 | 1,813,458 | 1,235,666 | 1,262,281 | 1,069,711 | 1,052,667 | 1,022,945 | 1,267,018 | 1,127,081 | 1,145,793 | 1,062,112 | 16,329,249 |
| | Jurisdictional Demand Recoverable Costs - Prod-Intm (B) | 59,324 | 59,324 | 59,324 | 59,324 | 59,324 | 53,508 | 53,508 | 53,508 | 46,692 | 46,692 | 46,692 | 46,692 | 643,912 |
| | Jurisdictional Demand Recoverable Costs - Prod-Peaking (B) | 0 | 35,012 | 0 | 0 | 0 | 0 | 0 | 0 | 30,552 | 0 | 63,414 | 0 | 128,978 |
| | Jurisdictional Demand Recoverable Costs - A&G (B) | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 131,616 |
| 9 | Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8) | $3,349,248 | $5,388,475 | $3,788,571 | $3,901,477 | $3,792,003 | $3,534,515 | $3,529,690 | $3,274,635 | $3,568,006 | $3,444,458 | $3,269,319 | $3,326,542 | $44,166,944 |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6
(C) As explained in the testimony of Garry Miller, $75K of 2015 temporary dust mitigation resulting from shift of permanent capital solution from October 2015 to October 2016 is included in Jan-16.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Capital Investment Projects-Recoverable Costs**
**(in Dollars)**

Form 42-3P

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)


| Line | Description | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investment Projects - System (A) | | | | | | | | | | | | | |
| 3.1 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| 4.1 | Above Ground Tank Secondary Containment - Peaking | 116,357 | 116,069 | 115,781 | 115,496 | 115,208 | 114,921 | 114,635 | 114,348 | 114,060 | 113,774 | 113,486 | 113,199 | 1,377,334 |
| 4.2 | Above Ground Tank Secondary Containment - Base | 24,937 | 24,911 | 24,885 | 24,858 | 24,832 | 24,806 | 24,780 | 24,754 | 24,728 | 24,702 | 24,676 | 24,649 | 297,518 |
| 4.3 | Above Ground Tank Secondary Containment - Intm | 2,700 | 2,696 | 2,691 | 2,687 | 2,683 | 2,678 | 2,674 | 2,669 | 2,664 | 2,660 | 2,655 | 2,650 | 32,107 |
| 5 | SO2/NOX Emissions Allowances - Energy | 90,075 | 87,387 | 84,690 | 81,995 | 79,305 | 76,610 | 73,915 | 71,217 | 68,521 | 65,828 | 63,146 | 60,466 | 903,155 |
| 7.1 | CAIR/CAMR Anclote- Intm | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.2 | CAIR/CAMR - Peaking | 18,804 | 18,775 | 18,745 | 18,711 | 18,684 | 18,651 | 18,622 | 18,590 | 18,558 | 18,531 | 18,499 | 18,468 | 223,638 |
| 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 | 42,190 | 43,219 | 43,666 | 44,115 | 44,563 | 45,007 | 45,456 | 45,904 | 46,348 | 46,797 | 47,246 | 47,692 | 542,203 |
| 7.4 | CAIR/CAMR Crystal River AFUDC - Energy | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 112,443 |
| 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 | 115 | 116 | 116 | 116 | 116 | 117 | 118 | 119 | 120 | 123 | 122 | 122 | 1,420 |
| 10.1 | Underground Storage Tanks - Base | 1,569 | 1,567 | 1,564 | 1,562 | 1,559 | 1,557 | 1,554 | 1,552 | 1,548 | 1,546 | 1,543 | 1,541 | 18,662 |
| 10.2 | Underground Storage Tanks - Intm | 733 | 731 | 730 | 728 | 726 | 725 | 722 | 721 | 720 | 717 | 716 | 714 | 8,683 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Intm | 154,003 | 153,692 | 153,383 | 153,073 | 152,763 | 152,453 | 152,143 | 151,833 | 151,523 | 151,214 | 150,903 | 150,593 | 1,827,576 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 37,668 | 37,612 | 37,555 | 37,499 | 37,443 | 37,386 | 37,330 | 37,273 | 37,217 | 37,160 | 37,103 | 37,047 | 448,291 |
| 17.1 | Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - | 1,430,070 | 1,427,963 | 1,425,857 | 1,423,751 | 1,421,646 | 1,419,540 | 1,417,433 | 1,415,327 | 1,413,221 | 1,411,115 | 1,409,009 | 1,406,902 | 17,021,828 |
| 17.2 | Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy | 246,827 | 250,632 | 257,005 | 262,083 | 263,275 | 279,122 | 278,455 | 277,789 | 277,122 | 276,456 | 275,790 | 275,123 | 3,219,684 |
| 18 | Coal Combustion Residual (CCR) Rule - Energy | (56,167) | 4,608 | 7,680 | 10,753 | 13,824 | 16,896 | 19,968 | 23,041 | 26,113 | 29,184 | 35,878 | 37,137 | 168,915 |
| 2 | Total Investment Projects - Recoverable Costs | $2,142,842 | $2,202,887 | $2,207,210 | $2,210,241 | $2,209,391 | $2,223,184 | $2,220,473 | $2,217,755 | $2,215,033 | $2,212,328 | $2,213,244 | $2,208,729 | $26,483,317 |
| 3 | Recoverable Costs Allocated to Energy | 1,757,843 | 1,817,572 | 1,822,157 | 1,825,451 | 1,824,863 | 1,838,924 | 1,836,471 | 1,834,017 | 1,831,564 | 1,829,113 | 1,830,296 | 1,826,045 | 21,874,316 |
| | Recoverable Costs Allocated to Distribution Demand | 115 | 116 | 116 | 116 | 116 | 117 | 118 | 119 | 120 | 123 | 122 | 122 | 1,420 |
| 4 | Recoverable Costs Allocated to Demand - Production - Base | 68,696 | 69,697 | 70,115 | 70,535 | 70,954 | 71,370 | 71,790 | 72,210 | 72,624 | 73,045 | 73,465 | 73,882 | 858,383 |
| | Recoverable Costs Allocated to Demand - Production - Intermediate | 181,027 | 180,658 | 180,296 | 179,932 | 179,566 | 179,201 | 178,837 | 178,471 | 178,107 | 177,742 | 177,376 | 177,013 | 2,148,226 |
| | Recoverable Costs Allocated to Demand - Production - Peaking | 135,161 | 134,844 | 134,526 | 134,207 | 133,892 | 133,572 | 133,257 | 132,938 | 132,618 | 132,305 | 131,985 | 131,667 | 1,600,972 |
| | Recoverable Costs Allocated to Demand - Production - Base (2012) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | Retail Energy Jurisdictional Factor | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | 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) | 1,719,630 | 1,774,762 | 1,791,627 | 1,785,225 | 1,773,798 | 1,784,825 | 1,776,920 | 1,769,887 | 1,770,287 | 1,768,762 | 1,769,281 | 1,783,548 | 21,268,554 |
| | Jurisdictional Demand Recoverable Costs - Distribution (B) | 114 | 115 | 115 | 115 | 115 | 116 | 117 | 118 | 119 | 122 | 121 | 121 | 1,414 |
| 8 | Jurisdictional Demand Recoverable Costs - Production - Base (C) | 63,808 | 64,738 | 65,126 | 65,516 | 65,906 | 66,292 | 66,682 | 67,072 | 67,457 | 67,848 | 68,238 | 68,625 | 797,309 |
| | Jurisdictional Demand Recoverable Costs - Production - Intermediate (C) | 131,612 | 131,344 | 131,081 | 130,816 | 130,550 | 130,285 | 130,020 | 129,754 | 129,489 | 129,224 | 128,958 | 128,694 | 1,561,825 |
| | Jurisdictional Demand Recoverable Costs - Production - Peaking (C) | 129,652 | 129,348 | 129,043 | 128,737 | 128,435 | 128,128 | 127,825 | 127,519 | 127,212 | 126,912 | 126,605 | 126,300 | 1,535,716 |
| | Jurisdictional Demand Recoverable Costs - Production - Base (2012) (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8) | $2,044,817 | $2,100,308 | $2,116,992 | $2,110,410 | $2,098,803 | $2,109,646 | $2,101,565 | $2,094,351 | $2,094,565 | $2,092,869 | $2,093,204 | $2,107,289 | $25,164,818 |

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, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | |
| 3 | Less: Accumulated Depreciation | (777,505) | (783,149) | (788,793) | (794,437) | (800,081) | (805,725) | (811,369) | (817,013) | (822,657) | (828,301) | (833,945) | (839,589) | (845,233) | |
| 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) | $1,837,200 | $1,831,556 | $1,825,912 | $1,820,268 | $1,814,624 | $1,808,980 | $1,803,336 | $1,797,692 | $1,792,048 | $1,786,404 | $1,780,760 | $1,775,116 | $1,769,472 | |
| 6 | Average Net Investment | | $1,834,378 | $1,828,734 | $1,823,090 | $1,817,446 | $1,811,802 | $1,806,158 | $1,800,514 | $1,794,870 | $1,789,226 | $1,783,582 | $1,777,938 | $1,772,294 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 3,098 | 3,087 | 3,078 | 3,069 | 3,059 | 3,050 | 3,040 | 3,031 | 3,021 | 3,012 | 3,002 | 2,994 | 36,541 |
| | b. Equity Component Grossed Up For Taxes | | 12,742 | 12,701 | 12,663 | 12,624 | 12,584 | 12,544 | 12,507 | 12,466 | 12,428 | 12,388 | 12,349 | 12,311 | 150,307 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 67,728 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 25,284 |
| | e. Other (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| 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) | | 17,151 | 17,114 | 17,079 | 17,044 | 17,008 | 16,973 | 16,938 | 16,902 | 16,867 | 16,831 | 16,796 | 16,762 | 203,467 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $17,151 | $17,114 | $17,079 | $17,044 | $17,008 | $16,973 | $16,938 | $16,902 | $16,867 | $16,831 | $16,796 | $16,762 | $203,467 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | |
| 3 | Less: Accumulated Depreciation | (2,805,915) | (2,839,142) | (2,872,369) | (2,905,596) | (2,938,823) | (2,972,050) | (3,005,277) | (3,038,504) | (3,071,731) | (3,104,958) | (3,138,185) | (3,171,412) | (3,204,639) | |
| 4 | CWIP - Non-Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $8,495,889 | $8,462,662 | $8,429,435 | $8,396,208 | $8,362,981 | $8,329,754 | $8,296,527 | $8,263,300 | $8,230,073 | $8,196,846 | $8,163,619 | $8,130,392 | $8,097,165 | |
| 6 | Average Net Investment | | $8,479,275 | $8,446,048 | $8,412,821 | $8,379,594 | $8,346,367 | $8,313,140 | $8,279,913 | $8,246,686 | $8,213,459 | $8,180,232 | $8,147,005 | $8,113,778 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 14,317 | 14,261 | 14,205 | 14,148 | 14,093 | 14,037 | 13,980 | 13,924 | 13,867 | 13,812 | 13,755 | 13,699 | 168,098 |
| | b. Equity Component Grossed Up For Taxes | | 58,896 | 58,664 | 58,432 | 58,204 | 57,971 | 57,740 | 57,511 | 57,280 | 57,049 | 56,818 | 56,587 | 56,356 | 691,508 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 398,724 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 119,004 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $116,357 | $116,069 | $115,781 | $115,496 | $115,208 | $114,921 | $114,635 | $114,348 | $114,060 | $113,774 | $113,486 | $113,199 | $1,377,334 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $116,357 | $116,069 | $115,781 | $115,496 | $115,208 | $114,921 | $114,635 | $114,348 | $114,060 | $113,774 | $113,486 | $113,199 | $1,377,334 |
| 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) | | 111,614 | 111,338 | 111,062 | 110,788 | 110,512 | 110,237 | 109,962 | 109,687 | 109,411 | 109,137 | 108,860 | 108,585 | 1,321,194 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $111,614 | $111,338 | $111,062 | $110,788 | $110,512 | $110,237 | $109,962 | $109,687 | $109,411 | $109,137 | $108,860 | $108,585 | $1,321,194 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | 100,001 | 96,969 | 93,937 | 90,905 | 87,873 | 84,841 | 81,809 | 78,777 | 75,745 | 72,713 | 69,681 | 66,649 | 63,617 | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | $2,499,040 | $2,496,008 | $2,492,976 | $2,489,944 | $2,486,912 | $2,483,880 | $2,480,848 | $2,477,816 | $2,474,784 | $2,471,752 | $2,468,720 | $2,465,688 | $2,462,656 | |
| 6 | Average Net Investment | | $2,497,524 | $2,494,492 | $2,491,460 | $2,488,428 | $2,485,396 | $2,482,364 | $2,479,332 | $2,476,300 | $2,473,268 | $2,470,236 | $2,467,204 | $2,464,172 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 4,217 | 4,212 | 4,207 | 4,201 | 4,196 | 4,191 | 4,186 | 4,181 | 4,177 | 4,171 | 4,166 | 4,161 | 50,266 |
| | b. Equity Component Grossed Up For Taxes | | 17,347 | 17,326 | 17,305 | 17,284 | 17,263 | 17,242 | 17,221 | 17,200 | 17,178 | 17,158 | 17,137 | 17,115 | 206,776 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 36,384 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 4,092 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $24,937 | $24,911 | $24,885 | $24,858 | $24,832 | $24,806 | $24,780 | $24,754 | $24,728 | $24,702 | $24,676 | $24,649 | $297,518 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $24,937 | $24,911 | $24,885 | $24,858 | $24,832 | $24,806 | $24,780 | $24,754 | $24,728 | $24,702 | $24,676 | $24,649 | $297,518 |
| 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) | | 23,163 | 23,139 | 23,114 | 23,089 | 23,065 | 23,041 | 23,017 | 22,993 | 22,969 | 22,944 | 22,920 | 22,895 | 276,350 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $23,163 | $23,139 | $23,114 | $23,089 | $23,065 | $23,041 | $23,017 | $22,993 | $22,969 | $22,944 | $22,920 | $22,895 | $276,350 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | (60,186) | (60,711) | (61,236) | (61,761) | (62,286) | (62,811) | (63,336) | (63,861) | (64,386) | (64,911) | (65,436) | (65,961) | (66,486) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | $230,112 | $229,587 | $229,062 | $228,537 | $228,012 | $227,487 | $226,962 | $226,437 | $225,912 | $225,387 | $224,862 | $224,337 | $223,812 | |
| 6 | Average Net Investment | | $229,849 | $229,324 | $228,799 | $228,274 | $227,749 | $227,224 | $226,699 | $226,174 | $225,649 | $225,124 | $224,599 | $224,074 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 388 | 387 | 386 | 385 | 385 | 384 | 383 | 382 | 381 | 380 | 379 | 378 | 4,598 |
| | b. Equity Component Grossed Up For Taxes | | 1,596 | 1,593 | 1,589 | 1,586 | 1,582 | 1,578 | 1,575 | 1,571 | 1,567 | 1,564 | 1,560 | 1,556 | 18,917 |
| | 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) | | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 2,292 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |
| 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) | | 1,963 | 1,960 | 1,956 | 1,954 | 1,951 | 1,947 | 1,944 | 1,940 | 1,937 | 1,934 | 1,930 | 1,927 | 23,343 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $1,963 | $1,960 | $1,956 | $1,954 | $1,951 | $1,947 | $1,944 | $1,940 | $1,937 | $1,934 | $1,930 | $1,927 | $23,343 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0158150 $SO_2$ Emission Allowance Inventory | | $3,333,608 | $3,324,785 | $3,315,961 | $3,304,982 | $3,296,584 | $3,287,013 | $3,277,343 | $3,267,414 | $3,257,471 | $3,247,532 | $3,238,730 | $3,230,982 | $3,222,750 | $3,222,750 |
| | b. 0254020 Auctioned $SO_2$ Allowance | | (4,039) | (4,039) | (4,039) | (4,039) | (4,298) | (4,289) | (4,281) | (4,272) | (4,264) | (4,256) | (4,247) | (4,239) | (4,230) | (4,230) |
| | c. 0158170 NOx Emission Allowance Inventory | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Other (A) | | 7,258,313 | 6,955,883 | 6,653,453 | 6,351,024 | 6,048,594 | 5,746,164 | 5,443,735 | 5,141,305 | 4,838,875 | 4,536,446 | 4,234,016 | 3,931,586 | 3,629,156 | 3,629,156 |
| 2 | Total Working Capital | | $10,587,882 | $10,276,629 | $9,965,375 | $9,651,967 | $9,340,880 | $9,028,888 | $8,716,797 | $8,404,447 | $8,092,083 | $7,779,722 | $7,468,499 | $7,158,329 | $6,847,676 | $6,847,676 |
| 3 | Average Net Investment | | | $10,432,255 | $10,121,002 | $9,808,671 | $9,496,424 | $9,184,884 | $8,872,843 | $8,560,622 | $8,248,265 | $7,935,902 | $7,624,110 | $7,313,414 | $7,003,003 | |
| 4 | Return on Average Net Working Capital Balance (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 17,615 | 17,089 | 16,562 | 16,035 | 15,509 | 14,982 | 14,455 | 13,927 | 13,400 | 12,873 | 12,349 | 11,825 | 176,621 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 72,460 | 70,298 | 68,128 | 65,960 | 63,796 | 61,628 | 59,460 | 57,290 | 55,121 | 52,955 | 50,797 | 48,641 | 726,534 |
| 5 | Total Return Component (C) | | | $90,075 | $87,387 | $84,690 | $81,995 | $79,305 | $76,610 | $73,915 | $71,217 | $68,521 | $65,828 | $63,146 | $60,466 | 903,155 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0509030 $SO_2$ Allowance Expense | | | $8,824 | $8,824 | $10,978 | $8,399 | $9,571 | $9,670 | $9,929 | $9,943 | $9,940 | $8,802 | $7,748 | $8,232 | 110,858 |
| | b. 0407426 Amortization Expense | | | 0 | 0 | 0 | 259 | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | 191 |
| | 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) | | | 8,824 | 8,824 | 10,978 | 8,657 | 9,562 | 9,661 | 9,921 | 9,934 | 9,931 | 8,793 | 7,740 | 8,223 | 111,050 |
| 8 | Amortization of NOx CAIR Emission Allowances (A) | | | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | 3,629,156 |
| 9 | Total System Recoverable Expenses (Lines 5 + 7) | | | $401,328 | $398,641 | $398,098 | $393,082 | $391,297 | $388,701 | $386,265 | $383,581 | $380,882 | $377,051 | $373,316 | $371,119 | |
| | a. Recoverable Costs Allocated to Energy | | | 98,899 | 96,211 | 95,668 | 90,652 | 88,867 | 86,271 | 83,836 | 81,151 | 78,452 | 74,621 | 70,886 | 68,689 | |
| | b. Recoverable Costs Allocated to Energy - NOx CAIR Emisssion Allowances (A) | | | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | |
| 10 | a. Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | b. NOx Regulatory Asset Energy Factor (12/2014) (A) | | | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | |
| 11 | Retail Energy-Related Recoverable Costs (E) | | | $96,749 | $93,945 | $94,065 | $88,654 | $86,381 | $83,733 | $81,117 | $78,314 | $75,828 | $72,159 | $68,523 | $67,091 | 986,559 |
| 12 | Retail Demand-Related Recoverable Costs (F) | | | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 13 | Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | | $ 392,918 | $ 390,114 | $ 390,235 | $ 384,824 | $ 382,550 | $ 379,903 | $ 377,287 | $ 374,483 | $ 371,997 | $ 368,329 | $ 364,692 | $ 363,260 | $ 4,540,592 |

Notes:

(A) Unusable NOx emission allowances due expiration of Clean Air Interstate Rule (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 conisistent with Order No. PSC-11-0553-FOF-EI.

(B) Line 3 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) Line 5 is reported on Capital Schedule

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

(E) Line 9a x Line 10a

(F) Line 9b x Line 10b

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | |
| 3 | Less: Accumulated Depreciation | (346,416) | (349,966) | (353,516) | (357,066) | (360,616) | (364,166) | (367,716) | (371,266) | (374,816) | (378,366) | (381,916) | (385,466) | (389,016) | |
| 4 | CWIP - Non-Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $1,589,692 | $1,586,142 | $1,582,592 | $1,579,042 | $1,575,492 | $1,571,942 | $1,568,392 | $1,564,842 | $1,561,292 | $1,557,742 | $1,554,192 | $1,550,642 | $1,547,092 | |
| 6 | Average Net Investment | | $1,587,917 | $1,584,367 | $1,580,817 | $1,577,267 | $1,573,717 | $1,570,167 | $1,566,617 | $1,563,067 | $1,559,517 | $1,555,967 | $1,552,417 | $1,548,867 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 2,680 | 2,675 | 2,670 | 2,662 | 2,658 | 2,651 | 2,646 | 2,639 | 2,632 | 2,629 | 2,621 | 2,614 | 31,777 |
| | b. Equity Component Grossed Up For Taxes | | 11,029 | 11,005 | 10,980 | 10,954 | 10,931 | 10,905 | 10,881 | 10,856 | 10,831 | 10,807 | 10,783 | 10,759 | 130,721 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 42,600 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 18,540 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $18,804 | $18,775 | $18,745 | $18,711 | $18,684 | $18,651 | $18,622 | $18,590 | $18,558 | $18,531 | $18,499 | $18,468 | 223,638 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $18,804 | $18,775 | $18,745 | $18,711 | $18,684 | $18,651 | $18,622 | $18,590 | $18,558 | $18,531 | $18,499 | $18,468 | 223,638 |
| 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) | | 18,038 | 18,010 | 17,981 | 17,948 | 17,922 | 17,891 | 17,863 | 17,832 | 17,802 | 17,776 | 17,745 | 17,715 | 214,523 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $18,038 | $18,010 | $17,981 | $17,948 | $17,922 | $17,891 | $17,863 | $17,832 | $17,802 | $17,776 | $17,745 | $17,715 | $214,523 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $713,122 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | |
| 3 | Less: Accumulated Depreciation | (106,469) | (114,097) | (121,725) | (129,353) | (136,981) | (144,609) | (152,237) | (159,865) | (167,493) | (175,121) | (182,749) | (190,377) | (198,005) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 59,427 | 118,854 | 178,281 | 237,707 | 297,134 | 356,561 | 415,988 | 475,415 | 534,842 | 594,268 | 653,695 | 713,122 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $3,844,399 | $3,896,197 | $3,947,996 | $3,999,795 | $4,051,594 | $4,103,393 | $4,155,192 | $4,206,990 | $4,258,789 | $4,310,588 | $4,362,387 | $4,414,186 | $4,465,985 | |
| 6 | Average Net Investment | | $3,870,298 | $3,922,097 | $3,973,896 | $4,025,694 | $4,077,493 | $4,129,292 | $4,181,091 | $4,232,890 | $4,284,689 | $4,336,487 | $4,388,286 | $4,440,085 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 6,649 | 6,850 | 6,938 | 7,026 | 7,114 | 7,199 | 7,288 | 7,376 | 7,462 | 7,550 | 7,638 | 7,725 | 86,815 |
| | b. Equity Component Grossed Up For Taxes | | 27,352 | 28,180 | 28,539 | 28,900 | 29,260 | 29,619 | 29,979 | 30,339 | 30,697 | 31,058 | 31,419 | 31,778 | 357,120 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 91,536 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (D) | | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 6,732 |
| | e. Other | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $42,190 | $43,219 | $43,666 | $44,115 | $44,563 | $45,007 | $45,456 | $45,904 | $46,348 | $46,797 | $47,246 | $47,692 | 542,203 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $42,190 | $43,219 | $43,666 | $44,115 | $44,563 | $45,007 | $45,456 | $45,904 | $46,348 | $46,797 | $47,246 | $47,692 | 542,203 |
| 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) | | 39,188 | 40,144 | 40,559 | 40,976 | 41,392 | 41,805 | 42,222 | 42,638 | 43,050 | 43,467 | 43,884 | 44,299 | 503,625 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $39,188 | $40,144 | $40,559 | $40,976 | $41,392 | $41,805 | $42,222 | $42,638 | $43,050 | $43,467 | $43,884 | $44,299 | $503,625 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**Schedule of Amortization and Return**
**For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-Products)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0154401 Ammonia Inventory | | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | 185,206 |
| | b. 0154200 Limestone Inventory | | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 |
| 2 | Total Working Capital | | $1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 |
| 3 | Average Net Investment | | | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | |
| 4 | Return on Average Net Working Capital Balance (A) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | $21,989 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 90,454 |
| 5 | Total Return Component (B) | | | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 112,443 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0502010 Ammonia Expense | | | 455,485 | 425,538 | 297,964 | 432,747 | 455,824 | 459,359 | 470,739 | 467,246 | 474,561 | 484,937 | 413,592 | 472,009 | 5,310,002 |
| | b. 0502040 Limestone Expense | | | 447,356 | 418,943 | 294,169 | 428,890 | 452,848 | 457,804 | 470,373 | 468,108 | 476,919 | 488,404 | 417,340 | 476,024 | 5,297,179 |
| | c. 0502050 Dibasic Acid Expense | | | 0 | 0 | 22,000 | 0 | 0 | 22,000 | 0 | 22,000 | 0 | 0 | 0 | 22,000 | 88,000 |
| | d. 0502070 Gypsum Disposal/Sale | | | 101,740 | 99,311 | 99,311 | 123,599 | 102,010 | 106,867 | 85,008 | 99,311 | 99,311 | 99,311 | 99,311 | 99,311 | 1,214,400 |
| | e. 0502040 Hydrated Lime Expense | | | 392,243 | 367,696 | 263,483 | 371,906 | 391,298 | 394,918 | 404,935 | 401,472 | 407,628 | 416,522 | 356,548 | 405,595 | 4,574,245 |
| | f. 0502300 Caustic Expense | | | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 300,000 |
| 7 | Net Expense (C) | | | 1,421,824 | 1,336,488 | 1,001,927 | 1,382,142 | 1,426,980 | 1,465,949 | 1,456,055 | 1,483,137 | 1,483,419 | 1,514,175 | 1,311,791 | 1,499,939 | 16,783,826 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | | $1,431,194 | $1,345,858 | $1,011,298 | $1,391,513 | $1,436,350 | $1,475,319 | $1,465,425 | $1,492,507 | $1,492,790 | $1,523,545 | $1,321,161 | $1,509,309 | $16,896,268 |
| | a. Recoverable Costs Allocated to Energy | | | 1,431,194 | 1,345,858 | 1,011,298 | 1,391,513 | 1,436,350 | 1,475,319 | 1,465,425 | 1,492,507 | 1,492,790 | 1,523,545 | 1,321,161 | 1,509,309 | 16,896,268 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | 1,400,082 | 1,314,159 | 994,353 | 1,360,849 | 1,396,157 | 1,431,917 | 1,417,906 | 1,440,318 | 1,442,847 | 1,473,276 | 1,277,119 | 1,474,184 | 16,423,168 |
| 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) | | | $ 1,400,082 | $ 1,314,159 | $ 994,353 | $ 1,360,849 | $ 1,396,157 | $ 1,431,917 | $ 1,417,906 | $ 1,440,318 | $ 1,442,847 | $ 1,473,276 | $ 1,277,119 | $ 1,474,184 | $ 16,423,168 |

Notes:

(A) Line 3 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $150 | $150 | $150 | $150 | $150 | $0 | $0 | $0 | $750 |
| | b. Clearings to Plant | | 300 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 750 | 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 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 12,374 | 12,374 | 12,374 | 12,374 | |
| 3 | Less: Accumulated Depreciation | (2,655) | (2,684) | (2,714) | (2,744) | (2,774) | (2,804) | (2,834) | (2,864) | (2,894) | (2,924) | (2,956) | (2,988) | (3,020) | |
| 4 | CWIP - Non-Interest Bearing | 300 | 0 | 0 | 0 | 0 | 150 | 300 | 450 | 600 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $8,969 | $8,940 | $8,910 | $8,880 | $8,850 | $8,970 | $9,090 | $9,210 | $9,330 | $9,450 | $9,418 | $9,386 | $9,354 | |
| 6 | Average Net Investment | | $8,954 | $8,925 | $8,895 | $8,865 | $8,910 | $9,030 | $9,150 | $9,270 | $9,390 | $9,434 | $9,402 | $9,370 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component 2.03% | | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 16 | 16 | 16 | 16 | 16 | 185 |
| | b. Equity Component Grossed Up For Taxes 8.33% | | 62 | 62 | 62 | 62 | 62 | 63 | 64 | 64 | 65 | 66 | 65 | 65 | 762 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) 3.0658% | | 29 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 32 | 32 | 32 | 365 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/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) 0.009035 | | 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) | | $115 | $116 | $116 | $116 | $116 | $117 | $118 | $119 | $120 | $123 | $122 | $122 | 1,420 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $115 | $116 | $116 | $116 | $116 | $117 | $118 | $119 | $120 | $123 | $122 | $122 | 1,420 |
| 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) | | 114 | 115 | 115 | 115 | 115 | 116 | 117 | 118 | 119 | 122 | 121 | 121 | 1,414 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $114 | $115 | $115 | $115 | $115 | $116 | $117 | $118 | $119 | $122 | $121 | $121 | $1,414 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | (35,344) | (35,640) | (35,936) | (36,232) | (36,528) | (36,824) | (37,120) | (37,416) | (37,712) | (38,008) | (38,304) | (38,600) | (38,896) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $133,597 | $133,301 | $133,005 | $132,709 | $132,413 | $132,117 | $131,821 | $131,525 | $131,229 | $130,933 | $130,637 | $130,341 | $130,045 | |
| 6 | Average Net Investment | | | $133,449 | $133,153 | $132,857 | $132,561 | $132,265 | $131,969 | $131,673 | $131,377 | $131,081 | $130,785 | $130,489 | $130,193 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 225 | 225 | 224 | 224 | 223 | 223 | 222 | 222 | 221 | 221 | 220 | 220 | 2,670 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 927 | 925 | 923 | 921 | 919 | 917 | 915 | 913 | 910 | 908 | 906 | 904 | 10,988 |
| | 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) | | | $1,569 | $1,567 | $1,564 | $1,562 | $1,559 | $1,557 | $1,554 | $1,552 | $1,548 | $1,546 | $1,543 | $1,541 | 18,662 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $1,569 | $1,567 | $1,564 | $1,562 | $1,559 | $1,557 | $1,554 | $1,552 | $1,548 | $1,546 | $1,543 | $1,541 | 18,662 |
| 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) | | | 1,457 | 1,456 | 1,453 | 1,451 | 1,448 | 1,446 | 1,443 | 1,442 | 1,438 | 1,436 | 1,433 | 1,431 | 17,334 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $1,457 | $1,456 | $1,453 | $1,451 | $1,448 | $1,446 | $1,443 | $1,442 | $1,438 | $1,436 | $1,433 | $1,431 | $17,334 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Duke Energy Florida, LLC
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | (21,785) | (21,988) | (22,191) | (22,394) | (22,597) | (22,800) | (23,003) | (23,206) | (23,409) | (23,612) | (23,815) | (24,018) | (24,221) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $54,221 | $54,018 | $53,815 | $53,612 | $53,409 | $53,206 | $53,003 | $52,800 | $52,597 | $52,394 | $52,191 | $51,988 | $51,785 | |
| 6 | Average Net Investment | | | $54,120 | $53,917 | $53,714 | $53,511 | $53,308 | $53,105 | $52,902 | $52,699 | $52,496 | $52,293 | $52,090 | $51,887 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 91 | 91 | 91 | 90 | 90 | 90 | 89 | 89 | 89 | 88 | 88 | 88 | 1,074 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 376 | 374 | 373 | 372 | 370 | 369 | 367 | 366 | 365 | 363 | 362 | 360 | 4,417 |
| | 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) | | | $733 | $731 | $730 | $728 | $726 | $725 | $722 | $721 | $720 | $717 | $716 | $714 | 8,683 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $733 | $731 | $730 | $728 | $726 | $725 | $722 | $721 | $720 | $717 | $716 | $714 | 8,683 |
| 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) | | | 533 | 531 | 531 | 529 | 528 | 527 | 525 | 524 | 523 | 521 | 521 | 519 | 6,313 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $533 | $531 | $531 | $529 | $528 | $527 | $525 | $524 | $523 | $521 | $521 | $519 | $6,313 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | |
| 3 | Less: Accumulated Depreciation | | (431,137) | (467,033) | (502,929) | (538,825) | (574,721) | (610,617) | (646,513) | (682,409) | (718,305) | (754,201) | (790,097) | (825,993) | (861,889) | |
| 4 | CWIP - Non-Interest Bearing | | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $12,463,374 | $12,427,478 | $12,391,582 | $12,355,686 | $12,319,790 | $12,283,894 | $12,247,998 | $12,212,102 | $12,176,206 | $12,140,310 | $12,104,414 | $12,068,518 | $12,032,622 | |
| 6 | Average Net Investment | | | $12,445,426 | $12,409,530 | $12,373,634 | $12,337,738 | $12,301,842 | $12,265,946 | $12,230,050 | $12,194,154 | $12,158,258 | $12,122,362 | $12,086,466 | $12,050,570 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 21,014 | 20,953 | 20,893 | 20,832 | 20,772 | 20,711 | 20,650 | 20,590 | 20,529 | 20,469 | 20,408 | 20,347 | 248,168 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 86,443 | 86,193 | 85,944 | 85,695 | 85,445 | 85,196 | 84,947 | 84,697 | 84,448 | 84,199 | 83,949 | 83,700 | 1,020,856 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.3333% | | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 430,752 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (D) | 0.009890 | | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 127,800 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $154,003 | $153,692 | $153,383 | $153,073 | $152,763 | $152,453 | $152,143 | $151,833 | $151,523 | $151,214 | $150,903 | $150,593 | 1,827,576 |
| | 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 | | | $154,003 | $153,692 | $153,383 | $153,073 | $152,763 | $152,453 | $152,143 | $151,833 | $151,523 | $151,214 | $150,903 | $150,593 | 1,827,576 |
| 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 - 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) | | | 111,965 | 111,739 | 111,514 | 111,289 | 111,063 | 110,838 | 110,613 | 110,387 | 110,162 | 109,937 | 109,711 | 109,486 | 1,328,703 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $111,965 | $111,739 | $111,514 | $111,289 | $111,063 | $110,838 | $110,613 | $110,387 | $110,162 | $109,937 | $109,711 | $109,486 | $1,328,703 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 1
(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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | |
| 3 | Less: Accumulated Depreciation | | (47,336) | (53,873) | (60,411) | (66,948) | (73,486) | (80,023) | (86,561) | (93,098) | (99,636) | (106,173) | (112,710) | (119,248) | (125,785) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $3,617,607 | $3,611,069 | $3,604,532 | $3,597,994 | $3,591,457 | $3,584,919 | $3,578,382 | $3,571,845 | $3,565,307 | $3,558,770 | $3,552,232 | $3,545,695 | $3,539,157 | |
| 6 | Average Net Investment | | | $3,614,338 | $3,607,801 | $3,601,263 | $3,594,726 | $3,588,188 | $3,581,651 | $3,575,113 | $3,568,576 | $3,562,038 | $3,555,501 | $3,548,963 | $3,542,426 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 6,103 | 6,092 | 6,081 | 6,070 | 6,059 | 6,048 | 6,037 | 6,026 | 6,015 | 6,003 | 5,992 | 5,981 | 72,507 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 25,104 | 25,059 | 25,013 | 24,968 | 24,923 | 24,877 | 24,832 | 24,786 | 24,741 | 24,696 | 24,650 | 24,605 | 298,254 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | Blended | | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 78,449 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 6,241 |
| | 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) | | | $37,668 | $37,612 | $37,555 | $37,499 | $37,443 | $37,386 | $37,330 | $37,273 | $37,217 | $37,160 | $37,103 | $37,047 | 448,291 |
| | a. Recoverable Costs Allocated to Energy | | | 37,668 | 37,612 | 37,555 | 37,499 | 37,443 | 37,386 | 37,330 | 37,273 | 37,217 | 37,160 | 37,103 | 37,047 | 448,291 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $36,849 | $36,726 | $36,926 | $36,673 | $36,395 | $36,286 | $36,119 | $35,970 | $35,972 | $35,934 | $35,866 | $36,185 | $435,901 |
| 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) | | | $36,849 | $36,726 | $36,926 | $36,673 | $36,395 | $36,286 | $36,119 | $35,970 | $35,972 | $35,934 | $35,866 | $36,185 | $435,901 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | |
| 3 | Less: Accumulated Depreciation | | (5,824,679) | (6,068,599) | (6,312,519) | (6,556,439) | (6,800,359) | (7,044,279) | (7,288,199) | (7,532,119) | (7,776,039) | (8,019,959) | (8,263,879) | (8,507,799) | (8,751,719) | |
| 4 | CWIP - AFUDC Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $128,925,596 | $128,681,676 | $128,437,756 | $128,193,836 | $127,949,916 | $127,705,996 | $127,462,076 | $127,218,156 | $126,974,236 | $126,730,316 | $126,486,396 | $126,242,476 | $125,998,556 | |
| 6 | Average Net Investment | | | $128,803,636 | $128,559,716 | $128,315,796 | $128,071,876 | $127,827,956 | $127,584,036 | $127,340,116 | $127,096,196 | $126,852,276 | $126,608,356 | $126,364,436 | $126,120,516 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 217,485 | 217,073 | 216,661 | 216,249 | 215,838 | 215,426 | 215,014 | 214,602 | 214,190 | 213,778 | 213,366 | 212,954 | 2,582,636 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 894,636 | 892,941 | 891,247 | 889,553 | 887,859 | 886,165 | 884,470 | 882,776 | 881,082 | 879,388 | 877,694 | 875,999 | 10,623,810 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.1722% | | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 2,927,040 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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) | 0.007910 | | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 1,065,876 |
| | 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) | | | $1,430,070 | $1,427,963 | $1,425,857 | $1,423,751 | $1,421,646 | $1,419,540 | $1,417,433 | $1,415,327 | $1,413,221 | $1,411,115 | $1,409,009 | $1,406,902 | 17,021,828 |
| | a. Recoverable Costs Allocated to Energy | | | 1,430,070 | 1,427,963 | 1,425,857 | 1,423,751 | 1,421,646 | 1,419,540 | 1,417,433 | 1,415,327 | 1,413,221 | 1,411,115 | 1,409,009 | 1,406,902 | 17,021,828 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $1,398,982 | $1,394,329 | $1,401,967 | $1,392,377 | $1,381,864 | $1,377,778 | $1,371,470 | $1,365,837 | $1,365,940 | $1,364,555 | $1,362,038 | $1,374,159 | $16,551,296 |
| 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) | | | $1,398,982 | $1,394,329 | $1,401,967 | $1,392,377 | $1,381,864 | $1,377,778 | $1,371,470 | $1,365,837 | $1,365,940 | $1,364,555 | $1,362,038 | $1,374,159 | $16,551,296 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 150007-EI
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $600,000 | $600,000 | $1,000,000 | $300,000 | $100,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,600,000 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 4,965,495 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | (194,715) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $20,070,225 | 20,070,225 | 20,070,225 | 20,070,225 | 20,070,225 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | |
| 3 | Less: Accumulated Depreciation | | (491,482) | (553,365) | (615,248) | (677,131) | (739,014) | (800,897) | (878,090) | (955,283) | (1,032,476) | (1,109,669) | (1,186,862) | (1,264,055) | (1,341,248) | |
| 4 | CWIP - Non-Interest Bearing | | 2,560,209 | 2,965,495 | 3,565,495 | 4,565,495 | 4,865,495 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $22,138,952 | $22,482,354 | $23,020,471 | $23,958,588 | $24,196,705 | $24,234,822 | $24,157,629 | $24,080,436 | $24,003,243 | $23,926,050 | $23,848,857 | $23,771,664 | $23,694,471 | |
| 6 | Average Net Investment | | | $22,310,653 | $22,751,413 | $23,489,530 | $24,077,647 | $24,215,764 | $24,196,226 | $24,119,033 | $24,041,840 | $23,964,647 | $23,887,454 | $23,810,261 | $23,733,068 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 37,672 | 38,416 | 39,662 | 40,655 | 40,888 | 40,855 | 40,725 | 40,595 | 40,464 | 40,334 | 40,204 | 40,073 | 480,543 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 154,964 | 158,025 | 163,152 | 167,237 | 168,196 | 168,061 | 167,524 | 166,988 | 166,452 | 165,916 | 165,380 | 164,844 | 1,976,739 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.7000% | | 61,883 | 61,883 | 61,883 | 61,883 | 61,883 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 849,766 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | | 2,848 | 2,848 | 2,848 | 2,848 | 2,848 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 39,111 |
| | 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) | | | $246,827 | $250,632 | $257,005 | $262,083 | $263,275 | $279,122 | $278,455 | $277,789 | $277,122 | $276,456 | $275,790 | $275,123 | 3,219,684 |
| | a. Recoverable Costs Allocated to Energy | | | 246,827 | 250,632 | 257,005 | 262,083 | 263,275 | 279,122 | 278,455 | 277,789 | 277,122 | 276,456 | 275,790 | 275,123 | 3,219,684 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $241,462 | $244,729 | $252,699 | $256,308 | $255,908 | $270,911 | $269,426 | $268,076 | $267,851 | $267,335 | $266,597 | $268,720 | $3,130,022 |
| 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) | | | $241,462 | $244,729 | $252,699 | $256,308 | $255,908 | $270,911 | $269,426 | $268,076 | $267,851 | $267,335 | $266,597 | $268,720 | $3,130,022 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 150007-EI
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Witness: T. G. Foster
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Return on Capital Investments, Depreciation and Taxes**
**For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Energy (Project 18)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $150,000 | $150,000 | $3,858,000 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,058,000 | 0 | 1,800,000 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | (1,600,000) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $1,600,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,058,000 | 2,058,000 | 3,858,000 | |
| 3 | Less: Accumulated Depreciation (A) | | (7,204) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (4,236) | (8,472) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 355,800 | 711,600 | 1,067,400 | 1,423,200 | 1,779,000 | 2,134,800 | 2,490,600 | 2,846,400 | 3,202,200 | 1,500,000 | 1,650,000 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $1,592,796 | $355,800 | $711,600 | $1,067,400 | $1,423,200 | $1,779,000 | $2,134,800 | $2,490,600 | $2,846,400 | $3,202,200 | $3,558,000 | $3,703,764 | $3,849,528 | |
| 6 | Average Net Investment | | | $974,298 | $533,700 | $889,500 | $1,245,300 | $1,601,100 | $1,956,900 | $2,312,700 | $2,668,500 | $3,024,300 | $3,380,100 | $3,630,882 | $3,776,646 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 1,645 | 901 | 1,502 | 2,103 | 2,703 | 3,304 | 3,905 | 4,506 | 5,107 | 5,707 | 6,131 | 6,377 | 43,891 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 6,767 | 3,707 | 6,178 | 8,650 | 11,121 | 13,592 | 16,063 | 18,535 | 21,006 | 23,477 | 25,219 | 26,232 | 180,547 |
| | c. Other (A) | | | (56,879) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (56,879) |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.4700% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4,236 | 4,236 | 8,472 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | 292 | 292 | 584 |
| | e. Other (A) | | | (7,700) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (7,700) |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | ($56,167) | $4,608 | $7,680 | $10,753 | $13,824 | $16,896 | $19,968 | $23,041 | $26,113 | $29,184 | $35,878 | $37,137 | 168,915 | |
| | a. Recoverable Costs Allocated to Energy | | (56,167) | 4,608 | 7,680 | 10,753 | 13,824 | 16,896 | 19,968 | 23,041 | 26,113 | 29,184 | 35,878 | 37,137 | 168,915 | |
| | b. Recoverable Costs Allocated to Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | | |
| 11 | Demand Jurisdictional Factor | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | ($54,946) | $4,499 | $7,551 | $10,516 | $13,437 | $16,399 | $19,321 | $22,235 | $25,239 | $28,221 | $34,682 | $36,273 | $163,427 | |
| 13 | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | ($54,946) | $4,499 | $7,551 | $10,516 | $13,437 | $16,399 | $19,321 | $22,235 | $25,239 | $28,221 | $34,682 | $36,273 | $163,427 | |

Notes:

(A) As explained in the testimony of Garry Miller, DEF has revised the permanent dust mitigation in-service date from October 2015 to October 2016 and determined vegetation management compliance can be achived without the 2015 capital investment. As a result, DEF has made these adjustments to ensure that the revenue requirement impact to customers is neutral.
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2nd Qtr end 2015, a total of 260 substation remediations are completed out of 279 slated for clean-up. DEF expects to remediate 3 more substations during the remainder of 2015.

**Project Fiscal Expenditures:**
2015 expenditures are estimated to be $405k lower than originally projected due to remediation work delays at the Consolidated Rock, Holder and Kenneth City substations.

**Project Progress Summary:**
DEF continues to remediate substation sites in accordance with the approved Substation Assessment and Remedial Action Plan (SARAP).

**Project Projections:**
2016 estimated expenditures are $1.1M.

**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:**
As of 2nd Qtr end 2015, there are 3 remaining Transformer Replacement and Inspection Program (TRIP) sites.

**Project Fiscal Expenditures:**
2015 expenditures are estimated to be $42k higher than originally projected due to costs to remove additional impacted soil at the three remaining sites.

**Project Progress Summary:**
This project is on schedule according to the approved Distribution System Investigation, Remediation and Pollution Prevention Program.

**Project Projections:**
2016 estimated expenditures are $3k.

**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) contains 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.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $19k higher than originally projected due to increased costs to comply with PIM regulations. No capital expenditures are estimated for 2015.

**Project Progress Summary:**
Ongoing regulatory compliance activities will continue until pipeline is sold or retired.

**Project Projections:**
2016 estimated O&M expenditures are $696k. No capital expenditures are expected in 2016.

**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 2015.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

**Project Projections:**
No project expenditures are expected in 2016.

**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 is treating its unused NOx costs as a regulatory asset amortizing it over 3 years, as approved by the Commission in Order No. PSC-11-0553-FOF-EI.

**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:**
2015 emission allowance expenditures are estimated to be $1.5M higher than originally projected due to unusable NOx emission allowances as a result of the expiration of the CAIR. CAIR was replaced by the CSAPR on 1/1/15. Consistent with Order No. PSC-11-0553-FOF-EI, DEF is treating costs associated with its unusable CAIR NOx emission allowances as a regulatory asset amortizing it over 3 years, beginning 1/1/15 until fully recovered by 12/31/17, with a return on the unamortized investment.

**Project Progress Summary:**
DEF continually evaluates the status of emission rules to maximize the cost effectiveness of its compliance strategy.

**Project Projections:**
2016 estimated expenditures are $111k. 2016 amortization of the CAIR NOx regulatory asset is approximately $3.6M.

**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.

**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 are under development to ensure compliance with all applicable requirements of the rule.

**Project Fiscal Expenditures:**
2015 project expenditures are estimated to be $43k lower than originally projected as methods used to allocate costs to analyze 316(b) compliance strategies at each affected Duke Energy station were adjusted to reflect present configurations and operations. DEF intends to implement a consistent approach across its entire fleet of regulated units to focus on full compliance with applicable 316(b) requirements through the development of facility specific strategic plans.

**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.

**Project Projections:**
2016 estimated O&M expenditures are $440k. No capital expenditures are expected in 2016.

**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 not 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)

**Project Accomplishments:**
The reclaimed water reuse system project was placed in-service in July 2015. This project will provide DEF with up to 1 1/2 million gallons per day of reclaimed water from the City of Crystal River to supplement well water use. This project has positive environmental impacts as it reduces aquifer use.

**Project Fiscal Expenditures:**
2015 estimated O&M expenditures are estimated to be $661k higher than originally projected due to a $710 decrease in CAIR Crystal River Project 7.4 - Base costs and $1.4 million increase in CAIR Crystal River Project 7.4 - Energy costs. The $710k is due to lower base routine project costs. The $1.4M is due to higher ammonia and hydrated lime costs offset by lower limestone and gypsum costs. 2015 estimated capital expenditures are expected to be $124k higher than originally projected due to a shift in spending from 2014 to 2015 in order to align with the City of Crystal River reclaimed water reuse project timeline.

**Project Progress Summary:**
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program.

**Project Projections:**
2016 estimated O&M and capital expenditures are $34.4M and $713k, 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 2015.

**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 2016.

**Project Title:** **Arsenic Groundwater Standard**
**Project No. 8**

**Project Description:**
On 1/22/01, the EPA adopted a new maximum contaminant level (MCL) for arsenic in drinking water replacing the previous standard of 0.050 mg/L (50ppb) with a new MCL of 0.010 mg/L (10ppb). 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 implications for land application and water reuse projects in Florida because the drinking water standard has been established as the groundwater standard by Rule 62-520.420(1), F.A.C. Lowering the arsenic standard will require new analytical methods for sampling groundwater at numerous DEF sites.

**Project Accomplishments:**
DEF has completed required monitoring as directed by the FDEP.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $23k higher than originally projected due to consultant costs to evaluate the source of arsenic exceedances and issue a summery report in compliance with FDEP Consent Order No. 09-3463C executed on 11/21/11. The Consent Order was issued by the FDEP for exceedance of the arsenic groundwater limit when the EPA lowered the arsenic maximum containment level from 50ppb to 10 ppb.

**Project Progress Summary:**
DEF is evaluating monitoring data and other options to achieve compliance in accordance to Consent Order.

**Project Projections:**
No project expenditures are expected in 2016.

**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:**
2015 capital expenditures are estimated to be $3k lower than originally projected. No new street lighting has been required in Franklin County, the City of Mexico Beach in Bay county or GULF County as DEF is in compliance with sea turtle ordinances. Also, the Don Cesar lighting project is delayed from 2014 to late 4th quarter 2015 due to scheduling conflicts.

**Project Progress Summary:**
DEF is on schedule with activities identified for this program.

**Project Projections:**
2016 estimated project O&M and capital expenditures are $450 and $750, 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

**Project Projections:**
No 2016 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 2015 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 2016 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. 060162-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 2015 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 180MWe 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 2016 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 2015 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 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
The mercury TMDL study concluded in 2012.

**Project Projections:**
No 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA during 2010.

**Project Projections:**
No 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA in September 2010.

**Project Projections:**
No 2016 expenditures are expected for this project.

**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 1/14/11, 2/14/11, 7/18/11,4/7/14 and 11/28/11, respectively. All facilities are required to meet new permitting conditions. In Docket No. 110007-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 thermal studies and whole effluent toxicity testing as required 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.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $54k lower than originally projected due to lower than expected 316(a) thermal study costs at the Anclote and Bartow stations. 2015 capital expenditures are expected to be $86k lower than originally projected due to a vendor reimbursement payment.

**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. DEF continues to work with FDEP to resolve the copper issue at the Suwannee station.

**Project Projections:**
2016 estimated O&M expenditures are $60k. No capital expenditures are expected in 2016.

**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-11-0553-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 the existing FGD and SCR systems as the primary MATS compliance measures. Additional monitoring and emissions reduction technologies will be installed in 2014 & 2015.

**Project Accomplishments:**
DEF installed ORP probes and particulate matter continuous emissions monitoring systems (PM CEMS) in 2014. In addition, a mercury characterization study was performed in late 2014, and temporary mercury re-emission control systems were installed in early 2015. DEF continues to monitor mercury emissions with Appendix K sorbent trap systems.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $153k higher than originally projected due to the addition of a temporary chemical injection system to control mercury emissions, and the cancellation of preliminary engineering for a fuel additive system to improve mercury oxidation. 2015 capital expenditures are expected to be $1.3M higher than originally projected driven by the installation of continuous emission monitoring systems (CEMS) for mercury monitoring, compliance demonstration and feedback to the re-emission control system.

**Project Progress Summary:**
Installation of mercury CEMS and permanent mercury re-emission control systems is scheduled in the third quarter of 2015. Certification and commissioning activities are expected to be completed by the end of the year.

**Project Projections:**
2016 estimated O&M is $529k. No capital expenditures are expected in 2016.

**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-12-0432-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:**
2015 capital expenditures are estimated to be $314k lower than originally projected due to earlier than expected completion of Unit 2 FD fan work in November 2013 versus December 2014. There are no recoverable O&M costs for this project.

**Project Progress Summary:**
This project is in-service.

**Project Projections:**
No 2016 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-14-0173-PAA-EI. DEF will make modifications to the electrostatic precipitators to improve particulate collection efficiency, as well as install reagent injection systems to reduce HCl and mercury emissions.

**Project Accomplishments:**
DEF finalized its CR1&2 MATS Compliance Plan in December 2013 and began implementation in early 2014.

**Project Fiscal Expenditures:**
2015 O&M expenditures are expected to be $51k lower than expected. Capital expenditures are estimated to be $4.2M higher than originally projected due to an additional project related to the Unit 1 electrostatic precipitator (ESP).

**Project Progress Summary:**
Implementation of the CR1&2 MATS Compliance Plan will be completed by April 2016.

**Project Projections:**
2016 estimated O&M and capital expenditures are $3.8M and $2.6M, respectively.

**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:**
DEF began defining and implementing of its CCR Rule compliance strategy.

**Project Fiscal Expenditures:**
2015 estimated O&M and capital expenditures are $391k and $1.6M, respectively.

**Project Progress Summary:**
Ash Landfill: Two engineering firms are studying Crystal River ash landfill stability and ash placement.
Temporary Gypsum Pad: Efforts are underway to address fugitive dust mitigation at the CCR gypsum stack-out.
FGD Blowdown Ponds: A definitive assessment and action plan is being developed.
Emergency Action Plan: A determination if the CCR requires an EPA for the FGD Blowdown Ponds is in process.
Vegetation Mgt & Inspection Work: More frequent mowing and inspection work is planned to comply with the CCR Rule.

**Project Projections:**
2016 estimated O&M and capital expenditures are $1.8M and $3.9M, respectively. See the August 31, 2015 direct testimony of Mr. Miller for 2015 CCR compliance strategy change.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of the Energy & Demand Allocation % by Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) Average 12CP Load Factor at Meter (%) | (2) Sales at Meter (mWh) | (3) Avg 12 CP at Meter (MW) (2)/(8784hrsx(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)/(8784hrs/(4)) | (9) mWh Sales at Source Energy Allocator (%) | (10) 12CP Demand Transmission Allocator (%) | (11) 12CP & 1/13 AD Demand Allocator (%) | (12) NCP Distribution Allocator (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | | | | | |
| **RS-1, RST-1, RSL-1, RSL-2, RSS-1** | | | | | | | | | | | | | |
| Secondary | 0.518 | 19,482,925 | 4,282.48 | 0.401 | 0.9463589 | 20,587,248 | 4,525.22 | 20,587,248 | 5,851.4 | 51.568% | 61.617% | 60.844% | 61.780% |
| **General Service Non-Demand** | | | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | | | |
| Secondary | 0.682 | 1,547,422 | 258.45 | 0.491 | 0.9463589 | 1,635,132 | 273.10 | 1,635,132 | 378.9 | 4.096% | 3.719% | 3.748% | 4.000% |
| Primary | 0.682 | 8,546 | 1.43 | 0.491 | 0.9766343 | 8,750 | 1.46 | 8,750 | 2.0 | 0.022% | 0.020% | 0.020% | 0.021% |
| Transmission | 0.682 | 3,571 | 0.60 | 0.491 | 0.9866343 | 3,619 | 0.60 | 0 | 0.0 | 0.009% | 0.008% | 0.008% | 0.000% |
| | | | | | | | | | | 4.127% | 3.747% | 3.776% | 4.021% |
| **General Service** | | | | | | | | | | | | | |
| **GS-2** Secondary | 1.000 | 161,981 | 18.44 | 1.000 | 0.9463589 | 171,162 | 19.49 | 171,162 | 19.5 | 0.429% | 0.265% | 0.278% | 0.206% |
| **General Service Demand** | | | | | | | | | | | | | |
| **GSD-1, GSDT-1** | | | | | | | | | | | | | |
| Secondary | 0.749 | 11,824,122 | 1,797.93 | 0.594 | 0.9463589 | 12,494,332 | 1,899.84 | 12,494,332 | 2,394.0 | 31.296% | 25.869% | 26.286% | 25.277% |
| Primary | 0.749 | 2,313,813 | 351.83 | 0.594 | 0.9766343 | 2,369,170 | 360.25 | 2,369,170 | 454.0 | 5.934% | 4.905% | 4.984% | 4.793% |
| Secondary Del/ Primary Mtr | 0.749 | 46,245 | 7.03 | 0.594 | 0.9766343 | 47,351 | 7.20 | 47,351 | 9.1 | 0.119% | 0.098% | 0.100% | 0.096% |
| Transm Del/ Primary Mtr | 0.749 | 1,419 | 0.22 | 0.594 | 0.9766343 | 1,453 | 0.22 | 0 | 0.0 | 0.004% | 0.003% | 0.003% | 0.000% |
| Transmission | 0.749 | 0 | 0.00 | 0.594 | 0.9866343 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| **SS-1** Primary | 1.166 | 5,602 | 0.55 | 0.093 | 0.9766343 | 5,736 | 0.56 | 5,736 | 7.0 | 0.014% | 0.008% | 0.008% | 0.074% |
| Transm Del/ Transm Mtr | 1.166 | 11,127 | 1.09 | 0.093 | 0.9866343 | 11,278 | 1.10 | 0 | 0.0 | 0.028% | 0.015% | 0.016% | 0.000% |
| Transm Del/ Primary Mtr | 1.166 | 3,474 | 0.34 | 0.093 | 0.9766343 | 3,557 | 0.35 | 0 | 0.0 | 0.009% | 0.005% | 0.005% | 0.000% |
| | | | | | | | | | | 37.404% | 30.902% | 31.403% | 30.240% |
| **Curtailable** | | | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, SS-3** | | | | | | | | | | | | | |
| Secondary | 1.305 | 0 | 0.00 | 0.456 | 0.9463589 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| Primary | 1.305 | 121,852 | 10.63 | 0.456 | 0.9766343 | 124,767 | 10.88 | 124,767 | 31.2 | 0.313% | 0.148% | 0.161% | 0.329% |
| **SS-3** Primary | 0.583 | 3,604 | 0.70 | 0.077 | 0.9766343 | 3,690 | 0.72 | 3,690 | 5.5 | 0.009% | 0.010% | 0.010% | 0.058% |
| | | | | | | | | | | 0.322% | 0.158% | 0.171% | 0.387% |
| **Interruptible** | | | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2** | | | | | | | | | | | | | |
| Secondary | 1.009 | 88,539 | 9.99 | 0.707 | 0.9463589 | 93,558 | 10.55 | 93,558 | 15.1 | 0.234% | 0.144% | 0.151% | 0.159% |
| Sec Del/Primary Mtr | 1.009 | 4,449 | 0.50 | 0.707 | 0.9766343 | 4,555 | 0.51 | 4,555 | 0.7 | 0.011% | 0.007% | 0.007% | 0.008% |
| Primary Del / Primary Mtr | 1.009 | 1,229,525 | 138.66 | 0.707 | 0.9766343 | 1,258,941 | 141.98 | 1,258,941 | 202.9 | 3.153% | 1.933% | 2.027% | 2.142% |
| Primary Del / Transm Mtr | 1.009 | 9,117 | 1.03 | 0.707 | 0.9866343 | 9,241 | 1.04 | 9,241 | 1.5 | 0.023% | 0.014% | 0.015% | 0.016% |
| Transm Del/ Transm Mtr | 1.009 | 222,224 | 25.06 | 0.707 | 0.9866343 | 225,234 | 25.40 | 0 | 0.0 | 0.564% | 0.346% | 0.363% | 0.000% |
| Transm Del/ Primary Mtr | 1.009 | 269,448 | 30.39 | 0.707 | 0.9766343 | 275,894 | 31.11 | 0 | 0.0 | 0.691% | 0.424% | 0.444% | 0.000% |
| **SS-2** Primary | 0.870 | 9,262 | 1.21 | 0.380 | 0.9766343 | 9,484 | 1.24 | 9,484 | 2.8 | 0.024% | 0.017% | 0.017% | 0.030% |
| Transm Del/ Transm Mtr | 0.870 | 92,038 | 12.05 | 0.380 | 0.9866343 | 93,285 | 12.21 | 0 | 0.0 | 0.234% | 0.166% | 0.171% | 0.000% |
| Transm Del/ Primary Mtr | 0.870 | 80,335 | 10.52 | 0.380 | 0.9766343 | 82,257 | 10.77 | 0 | 0.0 | 0.206% | 0.147% | 0.151% | 0.000% |
| | | | | | | | | | | 5.141% | 3.197% | 3.347% | 2.354% |
| **Lighting** | | | | | | | | | | | | | |
| **LS-1** (Secondary) | 5.506 | 381,551 | 7.89 | 0.479 | 0.9463589 | 403,178 | 8.34 | 403,178 | 95.8 | 1.010% | 0.114% | 0.182% | 1.012% |
| | | 37,922,191 | 6,969.01 | | | 39,922,874 | 7,344.16 | 39,226,296 | 9,471.2 | 100.000% | 100.000% | 100.000% | 100.000% |

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2015
(2) Projected kWh sales for the period January 2016 to December 2016
(3) Calculated: Column 2 / (8,784 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2015
(5) Based on system average line loss analysis for 2014
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,784 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 9 x 1/13 + Column 10 x 12/13
(12) Column 8/ Total Column 8

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) mWh Sales at Source Energy Allocator (%) | (2) 12CP Transmission Demand Allocator (%) | (3) 12CP & 1/13th AD Demand Allocator (%) | (4) NCP Distribution Allocator (%) | (5) Energy-Related Costs ($) | (6) Transmission Demand Costs ($) | (8) Production Demand Costs ($) | (7) Distribution Demand Costs ($) | (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 | 51.568% | 61.617% | 60.844% | 61.780% | $33,378,628 | $480,062 | $2,168,692 | ($164,617) | $35,862,765 | 19,482,925 | **0.184** |
| **General Service Non-Demand** | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 1,547,422 | **0.181** |
| Primary | | | | | | | | | | 8,461 | **0.179** |
| Transmission | | | | | | | | | | 3,500 | **0.177** |
| **TOTAL GS** | 4.127% | 3.747% | 3.776% | 4.021% | $2,671,137 | $29,191 | $134,590 | ($10,715) | $2,824,203 | **1,559,382** | |
| **General Service** | | | | | | | | | | | |
| **GS-2** Secondary | 0.429% | 0.265% | 0.278% | 0.206% | $277,510 | $2,067 | $9,905.12 | ($548.19) | $288,934 | 161,981 | **0.178** |
| **General Service Demand** | | | | | | | | | | | |
| **GSD-1, GSDT-1, SS-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 11,824,122 | **0.180** |
| Primary | | | | | | | | | | 2,346,847 | **0.178** |
| Transmission | | | | | | | | | | 10,904 | **0.176** |
| **TOTAL GSD** | 37.404% | 30.902% | 31.403% | 30.240% | $24,211,054 | $240,764 | $1,119,303 | ($80,575) | $25,490,546 | **14,181,874** | |
| **Curtailable** | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3** | | | | | | | | | | | |
| Secondary | | | | | | | | | | - | **0.173** |
| Primary | | | | | | | | | | 124,201 | **0.171** |
| Transmission | | | | | | | | | | - | **0.170** |
| **TOTAL CS** | 0.322% | 0.158% | 0.171% | 0.387% | $208,271 | $1,231 | $6,081 | ($1,030) | $214,553 | **124,201** | |
| **Interruptible** | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2, SS-2** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 88,539 | **0.175** |
| Primary | | | | | | | | | | 1,577,089 | **0.173** |
| Transmission | | | | | | | | | | 316,911 | **0.172** |
| **TOTAL IS** | 5.141% | 3.197% | 3.347% | 2.354% | $3,327,687 | $24,912 | $119,299 | ($6,274) | $3,465,624 | **1,982,539** | |
| **Lighting** | | | | | | | | | | | |
| **LS-1** Secondary | 1.010% | 0.114% | 0.182% | 1.012% | $653,683 | $884 | $6,503.57 | ($2,695.78) | $658,375 | 381,551 | **0.173** |
| | 100.000% | 100.000% | 100.000% | 100.000% | $64,727,970 | $779,111 | $3,564,373 | ($266,454) | $68,805,000 | 37,874,454 | **0.182** |

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 4 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
(8) Column 3 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 2016 to December 2016
(11) (Column 9/ Column 10)/10

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Capital Structure and Cost Rates**



| Class of Capital | | Retail Amount | Ratio | Cost Rate | Weighted Cost Rate | PreTax Weighted Cost Rate |
|---|---|---|---|---|---|---|
| CE | $ | 4,681,853 | 48.76% | 0.10500 | 5.120% | 8.335% |
| PS | | - | 0.00% | 0.00000 | 0.000% | 0.000% |
| LTD | | 3,672,596 | 38.25% | 0.05187 | 1.984% | 1.984% |
| STD | | (90,568) | -0.94% | 0.00170 | -0.002% | -0.002% |
| CD-Active | | 182,163 | 1.90% | 0.02306 | 0.044% | 0.044% |
| CD-Inactive | | 1,306 | 0.01% | 0.00000 | 0.000% | 0.000% |
| ADIT | | 1,318,615 | 13.73% | 0.00000 | 0.000% | 0.000% |
| FAS 109 | | (164,391) | -1.71% | 0.00000 | 0.000% | 0.000% |
| ITC | | 498 | 0.01% | 0.00000 | 0.000% | 0.000% |
| Total | $ | 9,602,073 | 100.00% | | 7.146% | 10.361% |
| | | | | Total Debt | 2.026% | 2.026% |
| | | | | Total Equity | 5.120% | 8.335% |

May 2015 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, Inc.

# Review of Integrated Clean Air Compliance Plan

**Submitted to the**
**Florida Public Service Commission**

April 1, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 19
PARTY: DUKE ENERGY FLORIDA, LLC
(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

CSAPR – Cross-State Air Pollution Rule

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

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

SCR – Selective Catalytic Reduction

SIP – Site Implementation Plan

$SO_2$ – Sulfur Dioxide

# Executive Summary

In the 2007 Environmental Cost Recovery Clause (ECRC) Docket (No. 070007-EI) and as reaffirmed in all subsequent ECRC Dockets (Nos. 080007-EI, 090007-EI, 100007-EI, 110007-EI, 120007-EI, 130007-EI, and 140007-EI), the Public Service Commission approved Duke Energy Florida's (DEF's) 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), Clean Air Mercury Rule (CAMR), 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 2015.

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 Units 4 and 5
- Fuel switching at Crystal River 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 Crystal River 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 Crystal River Units 4 and 5
- Installation of powdered activated carbon (PAC) injection on Crystal River Unit 2

As detailed in Docket No. 070007-EI, DEF decided upon 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 (Crystal River Units 4 and 5), and making strategic use of emission allowance markets.

In accordance with the Commission's final order in Docket No. 070007-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 Court of Appeals) stayed the effect of the Cross-State Air Pollution Rule (CSAPR) that the U.S. Environmental Protection Agency (EPA) had proposed to replace CAIR, leaving CAIR in effect until the Court completed its review of CSAPR. In August 2012 the D.C. Circuit Court of Appeals vacated the CSAPR in its entirety, and in January 2013, the court denied EPA's petition for a rehearing of the court's decision. EPA subsequently appealed the Court's vacatur to the U.S. Supreme Court, and oral argument was heard on December 10, 2013. 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 Court of Appeals 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 the new Mercury and Air Toxics Standards (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 Crystal River 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 DEF's Anclote Units 1 and 2 is to convert them to fire 100% natural gas rather than install emission controls in order to comply with the new MATS. The Commission approved DEF's petition for ECRC recovery of costs associated with the Anclote Conversion Project in Docket No. 120103-EI.

Suwannee Units 1, 2 & 3: DEF determined that no further modifications are needed on Suwannee Units 1, 2 and 3 in order to comply with MATS as they are currently capable of operating on 100% natural gas.

Crystal River Units 4 & 5: DEF will utilize the existing electrostatic precipitators (ESPs), FGDs, and SCRs at Crystal River Units 4 and 5 for MATS compliance. DEF will also install chemical injection systems in 2015 to mitigate mercury re-emissions from the FGDs. DEF requested a one year extension for all mercury-related MATS requirements on December 15, 2014. On March 12, 2015, the Florida Department of Environmental Protection (FDEP) authorized a one year extension to April 16, 2016. .

Crystal River Units 1 & 2: DEF 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 Best Available Retrofit Technology (BART) requirements until new generation can be built. This plan was approved by the Commission in Order No. PSC-14-0173-PAA-EI (April 17, 2014). Additionally, the FDEP granted a one-year extension to April 2016 for all MATS Units 1 and 2 requirements on February 6, 2014.

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 ongoing efforts to establish emission guidelines to address GHG from existing power plants under Section 111(d) of the federal Clean Air Act.

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. 070007-EI) and as reaffirmed in all subsequent ECRC Dockets (Nos. 080007-EI, 090007-EI, 100007-EI, 110007-EI, 120007-EI, 130007-EI, and 140007-EI), the Public Service Commission approved the Company'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-07-0922-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 PEF 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 2015.

# 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. 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, however, 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, the Commission has approved the Company's annual review of the Integrated Clean Air Compliance Plan. *See* Order No. PSC-14-0643-FOF-EI, at 9 (Nov. 4, 2014); Order No. PSC-13-0606-FOF-EI, at 9-10 (Nov. 19, 2013); Order No. PSC-12-0613-FOF-EI, at 16-17 (Nov. 16, 2012); Order No. PSC-11-0553-FOF-EI, at 13-14 (Dec. 7, 2011); Order No. PSC-10-0683-FOF-EI, at 6-7 (Nov. 15, 2010); Order No. PSC-09-0759-FOF-EI, at 18 (Nov. 18, 2009); Order No. 08-0775-FOF-EI, at 11 (Nov. 24, 2008).

## *A. Status of CAIR and CSAPR*

In July 2008, the U.S. Circuit Court of Appeals for the District of Columbia (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. 76 Fed. Reg. 48,208 (Aug. 8, 2011).

In Order No. PSC-11-0553-FOF-EI, issued in Docket No. 110007-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 has continued to maintain its $NO_x$ allowance inventory in order to comply with CAIR. Pursuant to the stipulation approved in Order No. PSC-11-0553-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. Litigation regarding CSAPR is ongoing as the D.C. Circuit heard oral argument on February 25, 2015.

Under the current terms of the CSAPR, the State of Florida is only affected by the ozone season requirements of the rule, which apply from May through September. The fact that annual $NO_x$ and $SO_2$ CSAPR programs are not required in Florida is due in large part to the installation and operation of emissions control projects designed to comply with CAIR.

## *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 establishes new MATS limits for emissions of various metals and acid gases from both coal- and oil-fired EGUs. The new standards apply to all existing coal- and oil-fired EGUs including DEF's Crystal River Units 1, 2, 4, and 5, Anclote Units 1 and 2, and Suwannee Units 1, 2, and 3. 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.

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 (Order No. PSC-11-0553-FOF-EI, at 11 (Dec. 7, 2011). 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-08-0775-FOF-EI, at 7 (Nov. 24, 2008), 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. Specifically, in 2011 and 2012, DEF requested and the Commission approved costs to perform emission testing, engineering and other analyses necessary to develop compliance strategies at Crystal River Units 4 and 5. Results of the 2012 analyses support the expectations stated in the 2012 Integrated Clean Air Plan that the FGDs and SCRs at Crystal River Units 4 and 5 will allow those units to comply with the new MATS standards under typical conditions. DEF conducted further testing in 2013 and those results confirmed expected performance levels. DEF will install chemical injection systems in 2015 to mitigate mercury re-emissions from the FGDs. The Company also completed its analysis of the impact of MATS on Suwannee Units 1, 2, and 3 and determined that no further modifications are needed on those units as they are currently capable of operating on 100% natural gas. In Docket 120103-EI, the Commission approved the Company's request for ECRC recovery of costs associated with the conversion of Anclote Units 1 and 2 to 100% natural gas fired capability as part of DEF's MATS compliance strategy. Finally, with respect to Crystal River Units 1 and 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 in compliance with MATS and BART requirements for a limited period of time until new generation can be built. This plan was approved by the Commission in Order No. PSC-14-0173-PAA-EI (April 17, 2014). Additionally, on February 6, 2014, the FDEP granted a one-year extension (to April 15, 2016) for MATS compliance at Crystal River units 1 and 2.

### *C. Greenhouse Gas Regulation*

In 2007, then-Governor Crist issued Executive Order 07-127 directing 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 FDEP to submit any such rules for legislative review and ratification. However, 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, 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 Crystal River 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 Crystal River 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 EPA to establish GHG emission guidelines for existing power plants under Section 111(d) of the Clean Air Act. The Presidential Memorandum directs 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 directs 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 June 2, 2014, EPA released the proposed New Source Performance Standards (NSPS) for $CO_2$ emissions from existing fossil fuel-fired EGUs. The proposal establishes state-specific emission rate goals; for Florida, the goals are 794 lb. $CO_2$/MWh annual average for the period 2020-2029 and 740 lb. $CO_2$/MWh for 2030 and beyond. EPA received over two million comments on the proposal by the comment deadline of December 1, 2014. EPA now expects to issue the final rule in mid- to late-summer of 2015.

## *D. Status of BART Requirements under CAVR*

In 2009, FDEP issued a permit imposing BART requirements for particulate matter (PM) emissions from Crystal River Units 1 and 2. The 2009 permit did not impose BART requirements for $SO_2$ and $NO_x$ emissions because, at the time, 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, EPA revised its previous determination to replace the "CAIR satisfies BART" assumption with "CSAPR satisfies BART." In late 2011, CSAPR was vacated (although recently 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 FDEP to develop and finalize air construction permits to address $SO_2$ and $NO_x$ emissions from Crystal River 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 EPA's approval of the Florida Regional Haze SIP, whichever is later, or alternatively the discontinuation of the use of coal in Crystal River Units 1 and 2 by December 31, 2020. The latter of the two options was ultimately selected by DEF.

As discussed in the Company's 2013 Integrated Clean Air Compliance Plan, 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 Crystal River Units 1 and 2. EPA formally approved 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)*

EPA and FDEP are working to implement a new 1-hour NAAQS for $SO_2$. In mid-2013, 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. EPA deferred making any area designations (attainment, nonattainment, or unclassifiable) for the remainder of the state. EPA released a proposed rule in April 2014 that describes requirements for additional ambient air quality monitoring and/or modeling that will be used to determine future rounds of area designations. Under that proposal, EPA would likely make future nonattainment designations in late 2017 for modeled areas and in late 2020 for monitored areas. DEF will continue to monitor these regulatory efforts and update the Commission on potential impact to DEF facilities.

EPA also revised its $NO_2$ NAAQS to implement a new 1-hour standard. At this time, however, DEF does not anticipate that the new standard will impact compliance measures at DEF facilities.

## *III. DEF's Integrated Clean Air Compliance Plan*

The Company's original compliance plan (Plan D) will continue to help DEF meet applicable environmental requirements by striking a balance between reducing emissions, primarily through installation of controls on its largest and newest coal units (Crystal River Units 4 and 5), and making strategic use of the allowance markets to comply with CSAPR requirements. 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 Crystal River Units 4 and 5 to

comply with $SO_2$ requirements of the CAIR, Title IV of the Clean Air Act, and $SO_2$ control requirements in DEF's air permits for these units. Together with the SCR systems discussed below, the FGDs also reduce mercury and other air toxic emissions and, therefore, will be a key component of DEF's MATS compliance strategy. The co-benefits of the FGDs and SCRs are expected to reduce mercury emissions by approximately 90%.

### *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 Crystal River Units 4 and 5. These controls enable DEF to comply with CAIR/CSAPR and other $NO_x$ control requirements included in DEF's air permits for the units. As discussed above, the SCRs also will help achieve MATS requirements for mercury. DEF has also 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 CSAPR was lifted and went into effect on January 1, 2015 replacing CAIR. Under CSAPR, the State of Florida is only affected by the ozone season requirements of the rule, which apply May through September. Consequently, DEF has NOx CAIR emission allowances that cannot be used to comply with CSAPR. DEF has established a regulatory asset to recover the costs of its remaining NOx CAIR emission allowance inventory over a three year amortization period beginning January 2015 in accordance with Order No. PSC-11-0553-FOF-EI.

### *C. Additional MATS Compliance Strategies*

The Company determined that the most cost-effective option for its Anclote Units 1 and 2 is conversion to fire 100% natural gas versus installation of emission controls to comply with MATS for oil-fired EGUs. This was approved by the Commission in Docket 120103-EI.

With respect to Suwannee Units 1, 2 and 3, DEF intends to comply with MATS by running the units exclusively on natural gas.

As noted above, DEF will utilize the co-benefits of the existing FGD and SCR systems as the primary MATS control technologies for Crystal River Units 4 and 5, and DEF conducted tests in 2013 to confirm expected performance levels. DEF will also install chemical injection systems in 2015 to mitigate mercury re-emissions from the FGDs.

For Crystal River Units 1 and 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 through Order No. PSC-14-0173-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 Crystal River 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 Crystal River 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 Crystal River 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 scheduled to take effect in 2018. As presented in the Company's petition approved in Order PSC-14-0173-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 Crystal River 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 Crystal River Units 4 and 5 as contemplated in prior ECRC filings. Units 4 and 5 FGD and SCR projects are now in-service, and targeted environmental benefits have been met or exceeded. As noted above, in addition to reducing $SO_2$ and $NO_x$ emissions, the FGDs and SCRs have the combined effect of reducing

mercury emissions and other air toxics which will contribute to DEF's plans to comply with MATS.

With regard to Crystal River Units 1 and 2, the Commission approved DEF's Need Petition in Docket No. 140110-EI to construct the Citrus Combined Cycle Units which are scheduled for in-service in 2018 and will allow for the retirement of these coal units once the new combined cycle units are operational. DEF has also obtained permits necessary to install pollution controls needed to extend operation of Crystal River Units 1 and 2 in compliance with MATS and BART until the Citrus units are operational.

DEF determined that converting Anclote Units 1 and 2 to fire 100% natural gas is more cost-effective than installing emission controls in order to comply with MATS. Conversion of both units was completed in 2013 with necessary upgrade to the forced draft (FD) fans to maintain unit output completed in 2014.

DEF completed its analysis of the impact of MATS on Suwannee Units 1, 2, and 3 and concluded that no further modifications are needed.

## *B. Projects Costs*

Crystal River Units 4 and 5 FGD and SCR projects are now in-service, and the targeted environmental benefits have been met or exceeded. The Anclote units have been converted to fire 100% natural gas.. DEF intends to continue operating Crystal River Units 1 and 2 in compliance with BART and MATS requirements as outlined in Order No. PSC-14-0173-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)) could influence decisions with regard to control technologies to meet new standards. The rule was issued on 5/19/14 with an effective date of 10/14/14. The requirements are currently being assessed in conjunction with air regulations, and DEF's compliance strategies may be altered when this evaluation is complete.
- EPA proposed updated Steam Electric Effluent Limitation Guidelines (ELG) for electric power plants in the summer of 2013 with final adoption pending

negotiations between the EPA and environmental groups. A final rule is expected by 9/30/15. These standards are expected to affect decisions associated with the treatment of wastewater generated by wet FGDs.

- EPA signed the final Coal Combustion Residuals (CCR) rule on December 19, 2014. Publication of the final rule is still pending. This rule is expected to affect decisions associated with the handling of CCRs, including fly ash, bottom ash, and materials generated from operation of wet FGDs, including synthetic gypsum.
- On June 2, 2014 EPA released the proposed New Source Performance Standards (NSPS) for $CO_2$ emissions from existing fossil fuel-fired EGUs. The proposal establishes aggressive state-specific emission rate goals for the period 2020-2029 and for 2030 and beyond. EPA expects to issue the final rule in mid- to late-summer of 2015. These standards may result in additional changes to DEF's compliance strategies.

# V. Conclusion

DEF has completed installation of the emission controls contemplated in its approved Plan D on time and within budget. The new FGD and SCR systems at Crystal River Units 4 and 5 have enabled DEF to comply with CAIR 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 compliance strategies under development, will enable the Company to achieve and maintain compliance with applicable regulations, including MATS, in a cost-effective manner.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Commission Forms 42-1P Through 42-8P**

**January 2016 - December 2016**
**Calculation of Projected Period Amount**

**Docket No. 150007-EI**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 20
PARTY: DUKE ENERGY FLORIDA, LLC
(DEF) – (DIRECT)
DESCRIPTION: Patricia Q. West TGF-5

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

| 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) | $42,339,858 | $329,256 | $621,710 | $876,120 | $44,166,944 |
| b | Projected Capital Projects (Form 42-3P, Lines 7 through 9) | 22,049,877 | 0 | 1,414 | 3,176,702 | 25,227,993 |
| c | Total Jurisdictional Rev Req for the Projected Period (Lines 1a + 1b) | 64,389,735 | 329,256 | 623,124 | 4,052,822 | 69,394,937 |
| 2 | True-up for Estimated Over/(Under) Recovery for the Current Period January 2015 - December 2015 (Form 42-2E, Line 5 + 6 + 10) | (1,720,135) | (350,923) | 885,148 | 406,308 | (779,602) |
| 3 | Final True-up for the Period January 2014 - December 2014 (Form 42-1A, Line 3) | 1,428,470 | (98,371) | 4,238 | 84,706 | 1,419,043 |
| 4 | Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection Period January 2016 - December 2016 (Line 1 - Line 2 - Line 3) | 64,681,400 | 778,551 | (266,263) | 3,561,808 | 68,755,496 |
| 5 | Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072) | $64,727,970 | $779,111 | ($266,454) | $3,564,373 | $68,805,000 |

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**O&M Activities**
**(in Dollars)**

Form 42-2P

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)


| Line | Description | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | O&M Activities - System | | | | | | | | | | | | | |
| 1 | Transmission Substation Environmental Investigation, Remediation and Pollution Prevention | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $39,083 | $469,000 |
| 1a | Distribution Substation Environmental Investigation, Remediation and Pollution Prevention | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 621,000 |
| 2 | Distribution System Environmental Investigation, Remediation and Pollution Prevention | 3,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,000 |
| 3 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 61,098 | 51,723 | 51,723 | 51,723 | 51,723 | 695,676 |
| 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 | 8,824 | 8,824 | 10,978 | 8,657 | 9,562 | 9,661 | 9,921 | 9,934 | 9,931 | 8,793 | 7,740 | 8,223 | 111,050 |
| 5 | NOx Emissions Allowances Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 6 | Phase II Cooling Water Intake 316(b) - Base | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 12,500 | 12,500 | 37,500 | 250,000 |
| 6a | Phase II Cooling Water Intake 316(b) - Intm | 20,500 | 20,500 | 20,500 | 20,500 | 20,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 12,500 | 190,000 |
| 7.2 | CAIR/CAMR - Peaking | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 31,850 | 0 | 66,109 | 0 | 134,459 |
| 7.4 | CAIR/CAMR Crystal River - Base | 1,119,721 | 3,452,919 | 1,914,869 | 1,317,818 | 1,346,472 | 1,114,151 | 1,120,802 | 1,088,803 | 1,326,571 | 1,200,915 | 1,221,061 | 1,105,970 | 17,330,071 |
| 7.4 | CAIR/CAMR Crystal River - Energy | 1,421,824 | 1,336,488 | 1,001,927 | 1,382,142 | 1,426,980 | 1,465,949 | 1,456,055 | 1,483,137 | 1,483,419 | 1,514,175 | 1,311,791 | 1,499,939 | 16,783,826 |
| 7.4 | CAIR/CAMR Crystal River - A&G | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 141,192 |
| 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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Sea Turtle - Coastal Street Lighting - Distrib | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 50 | 50 | 50 | 0 | 0 | 450 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Energy | 0 | 0 | 18,232 | 0 | 4,290 | 7,500 | 0 | 0 | 18,232 | 0 | 4,290 | 7,500 | 60,044 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 43,283 | 48,283 | 48,283 | 43,283 | 43,283 | 529,400 |
| 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 | 266,003 | 266,003 | 406,003 | 542,253 | 366,003 | 266,003 | 302,253 | 266,003 | 266,003 | 302,253 | 266,003 | 266,003 | 3,780,792 |
| 18 | Coal Combustion Residual (CCR) Rule - Energy (C) | 150,333 | 75,333 | 75,333 | 294,083 | 294,083 | 294,083 | 294,083 | 75,333 | 75,333 | 75,333 | 50,333 | 50,333 | 1,804,000 |
| 2 | Total O&M Activities - Recoverable Costs | $3,512,115 | $5,718,478 | $3,994,753 | $4,087,364 | $3,989,901 | $3,716,858 | $3,717,624 | $3,457,671 | $3,766,426 | $3,631,555 | $3,452,362 | $3,488,005 | $46,533,115 |
| 3 | Recoverable Costs Allocated to Energy | 1,890,267 | 1,729,932 | 1,555,758 | 2,270,419 | 2,144,202 | 2,086,481 | 2,105,596 | 1,877,691 | 1,901,203 | 1,948,838 | 1,683,441 | 1,875,283 | 23,069,111 |
| | Recoverable Costs Allocated to Energy - NOx Regulatory Asset | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 3,629,156 |
| 4 | Recoverable Costs Allocated to Demand - Transm | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 39,083 | 469,000 |
| | Recoverable Costs Allocated to Demand - Distrib | 54,750 | 51,750 | 51,750 | 51,750 | 51,850 | 51,850 | 51,850 | 51,800 | 51,800 | 51,800 | 51,750 | 51,750 | 624,450 |
| | Recoverable Costs Allocated to Demand - Prod-Base | 1,132,221 | 3,465,419 | 1,952,369 | 1,330,318 | 1,358,972 | 1,151,651 | 1,133,302 | 1,101,303 | 1,364,071 | 1,213,415 | 1,233,561 | 1,143,470 | 17,580,071 |
| | Recoverable Costs Allocated to Demand - Prod-Intm | 81,598 | 81,598 | 81,598 | 81,598 | 81,598 | 73,598 | 73,598 | 73,598 | 64,223 | 64,223 | 64,223 | 64,223 | 885,676 |
| | Recoverable Costs Allocated to Demand - Prod-Peaking | 0 | 36,500 | 0 | 0 | 0 | 0 | 0 | 0 | 31,850 | 0 | 66,109 | 0 | 134,459 |
| | Recoverable Costs Allocated to Demand - A&G | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 11,766 | 141,192 |
| 5 | Retail Energy Jurisdictional Factor | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | 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) | 1,849,176 | 1,689,187 | 1,529,691 | 2,220,389 | 2,084,201 | 2,025,099 | 2,037,318 | 1,812,034 | 1,837,596 | 1,884,537 | 1,627,322 | 1,831,640 | 22,428,190 |
| | Retail Energy Jurisdictional Factor - NOx Regulatory Asset (A) | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 8 | Jurisdictional Demand Recoverable Costs - Transm (B) | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 27,438 | 329,256 |
| | Jurisdictional Demand Recoverable Costs - Distrib (B) | 54,510 | 51,523 | 51,523 | 51,523 | 51,622 | 51,622 | 51,622 | 51,573 | 51,573 | 51,573 | 51,523 | 51,523 | 621,710 |
| | Jurisdictional Demand Recoverable Costs - Prod-Base (B) | 1,051,663 | 3,218,854 | 1,813,458 | 1,235,666 | 1,262,281 | 1,069,711 | 1,052,667 | 1,022,945 | 1,267,018 | 1,127,081 | 1,145,793 | 1,062,112 | 16,329,249 |
| | Jurisdictional Demand Recoverable Costs - Prod-Intm (B) | 59,324 | 59,324 | 59,324 | 59,324 | 59,324 | 53,508 | 53,508 | 53,508 | 46,692 | 46,692 | 46,692 | 46,692 | 643,912 |
| | Jurisdictional Demand Recoverable Costs - Prod-Peaking (B) | 0 | 35,012 | 0 | 0 | 0 | 0 | 0 | 0 | 30,552 | 0 | 63,414 | 0 | 128,978 |
| | Jurisdictional Demand Recoverable Costs - A&G (B) | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 10,968 | 131,616 |
| 9 | Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8) | $3,349,248 | $5,388,475 | $3,788,571 | $3,901,477 | $3,792,003 | $3,534,515 | $3,529,690 | $3,274,635 | $3,568,006 | $3,444,458 | $3,269,319 | $3,326,542 | $44,166,944 |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6
(C) As explained in the testimony of Garry Miller, $75K of 2015 temporary dust mitigation resulting from shift of permanent capital solution from October 2015 to October 2016 is included in Jan-16.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Capital Investment Projects-Recoverable Costs**
**(in Dollars)**

Form 42-3P

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)


| Line | Description | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investment Projects - System (A) | | | | | | | | | | | | | |
| 3.1 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| 4.1 | Above Ground Tank Secondary Containment - Peaking | 116,357 | 116,069 | 115,781 | 115,496 | 115,208 | 114,921 | 114,635 | 114,348 | 114,060 | 113,774 | 113,486 | 113,199 | 1,377,334 |
| 4.2 | Above Ground Tank Secondary Containment - Base | 24,937 | 24,911 | 24,885 | 24,858 | 24,832 | 24,806 | 24,780 | 24,754 | 24,728 | 24,702 | 24,676 | 24,649 | 297,518 |
| 4.3 | Above Ground Tank Secondary Containment - Intm | 2,700 | 2,696 | 2,691 | 2,687 | 2,683 | 2,678 | 2,674 | 2,669 | 2,664 | 2,660 | 2,655 | 2,650 | 32,107 |
| 5 | SO2/NOX Emissions Allowances - Energy | 90,075 | 87,387 | 84,690 | 81,995 | 79,305 | 76,610 | 73,915 | 71,217 | 68,521 | 65,828 | 63,146 | 60,466 | 903,155 |
| 7.1 | CAIR/CAMR Anclote- Intm | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.2 | CAIR/CAMR - Peaking | 18,804 | 18,775 | 18,745 | 18,711 | 18,684 | 18,651 | 18,622 | 18,590 | 18,558 | 18,531 | 18,499 | 18,468 | 223,638 |
| 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 | 42,190 | 43,219 | 43,666 | 44,115 | 44,563 | 45,007 | 45,456 | 45,904 | 46,348 | 46,797 | 47,246 | 47,692 | 542,203 |
| 7.4 | CAIR/CAMR Crystal River AFUDC - Energy | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 112,443 |
| 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 | 115 | 116 | 116 | 116 | 116 | 117 | 118 | 119 | 120 | 123 | 122 | 122 | 1,420 |
| 10.1 | Underground Storage Tanks - Base | 1,569 | 1,567 | 1,564 | 1,562 | 1,559 | 1,557 | 1,554 | 1,552 | 1,548 | 1,546 | 1,543 | 1,541 | 18,662 |
| 10.2 | Underground Storage Tanks - Intm | 733 | 731 | 730 | 728 | 726 | 725 | 722 | 721 | 720 | 717 | 716 | 714 | 8,683 |
| 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 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Intm | 154,003 | 153,692 | 153,383 | 153,073 | 152,763 | 152,453 | 152,143 | 151,833 | 151,523 | 151,214 | 150,903 | 150,593 | 1,827,576 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 37,668 | 37,612 | 37,555 | 37,499 | 37,443 | 37,386 | 37,330 | 37,273 | 37,217 | 37,160 | 37,103 | 37,047 | 448,291 |
| 17.1 | Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - | 1,430,070 | 1,427,963 | 1,425,857 | 1,423,751 | 1,421,646 | 1,419,540 | 1,417,433 | 1,415,327 | 1,413,221 | 1,411,115 | 1,409,009 | 1,406,902 | 17,021,828 |
| 17.2 | Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy | 246,827 | 250,632 | 257,005 | 262,083 | 263,275 | 279,122 | 278,455 | 277,789 | 277,122 | 276,456 | 275,790 | 275,123 | 3,219,684 |
| 18 | Coal Combustion Residual (CCR) Rule - Energy | (56,167) | 4,608 | 7,680 | 10,753 | 13,824 | 16,896 | 19,968 | 23,041 | 26,113 | 29,184 | 35,878 | 37,137 | 168,915 |
| 2 | Total Investment Projects - Recoverable Costs | $2,142,842 | $2,202,887 | $2,207,210 | $2,210,241 | $2,209,391 | $2,223,184 | $2,220,473 | $2,217,755 | $2,215,033 | $2,212,328 | $2,213,244 | $2,208,729 | $26,483,317 |
| 3 | Recoverable Costs Allocated to Energy | 1,757,843 | 1,817,572 | 1,822,157 | 1,825,451 | 1,824,863 | 1,838,924 | 1,836,471 | 1,834,017 | 1,831,564 | 1,829,113 | 1,830,296 | 1,826,045 | 21,874,316 |
| | Recoverable Costs Allocated to Distribution Demand | 115 | 116 | 116 | 116 | 116 | 117 | 118 | 119 | 120 | 123 | 122 | 122 | 1,420 |
| 4 | Recoverable Costs Allocated to Demand - Production - Base | 68,696 | 69,697 | 70,115 | 70,535 | 70,954 | 71,370 | 71,790 | 72,210 | 72,624 | 73,045 | 73,465 | 73,882 | 858,383 |
| | Recoverable Costs Allocated to Demand - Production - Intermediate | 181,027 | 180,658 | 180,296 | 179,932 | 179,566 | 179,201 | 178,837 | 178,471 | 178,107 | 177,742 | 177,376 | 177,013 | 2,148,226 |
| | Recoverable Costs Allocated to Demand - Production - Peaking | 135,161 | 134,844 | 134,526 | 134,207 | 133,892 | 133,572 | 133,257 | 132,938 | 132,618 | 132,305 | 131,985 | 131,667 | 1,600,972 |
| | Recoverable Costs Allocated to Demand - Production - Base (2012) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | Retail Energy Jurisdictional Factor | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | 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) | 1,719,630 | 1,774,762 | 1,791,627 | 1,785,225 | 1,773,798 | 1,784,825 | 1,776,920 | 1,769,887 | 1,770,287 | 1,768,762 | 1,769,281 | 1,783,548 | 21,268,554 |
| | Jurisdictional Demand Recoverable Costs - Distribution (B) | 114 | 115 | 115 | 115 | 115 | 116 | 117 | 118 | 119 | 122 | 121 | 121 | 1,414 |
| 8 | Jurisdictional Demand Recoverable Costs - Production - Base (C) | 63,808 | 64,738 | 65,126 | 65,516 | 65,906 | 66,292 | 66,682 | 67,072 | 67,457 | 67,848 | 68,238 | 68,625 | 797,309 |
| | Jurisdictional Demand Recoverable Costs - Production - Intermediate (C) | 131,612 | 131,344 | 131,081 | 130,816 | 130,550 | 130,285 | 130,020 | 129,754 | 129,489 | 129,224 | 128,958 | 128,694 | 1,561,825 |
| | Jurisdictional Demand Recoverable Costs - Production - Peaking (C) | 129,652 | 129,348 | 129,043 | 128,737 | 128,435 | 128,128 | 127,825 | 127,519 | 127,212 | 126,912 | 126,605 | 126,300 | 1,535,716 |
| | Jurisdictional Demand Recoverable Costs - Production - Base (2012) (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8) | $2,044,817 | $2,100,308 | $2,116,992 | $2,110,410 | $2,098,803 | $2,109,646 | $2,101,565 | $2,094,351 | $2,094,565 | $2,092,869 | $2,093,204 | $2,107,289 | $25,164,818 |

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, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | $2,614,704 | |
| 3 | Less: Accumulated Depreciation | (777,505) | (783,149) | (788,793) | (794,437) | (800,081) | (805,725) | (811,369) | (817,013) | (822,657) | (828,301) | (833,945) | (839,589) | (845,233) | |
| 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) | $1,837,200 | $1,831,556 | $1,825,912 | $1,820,268 | $1,814,624 | $1,808,980 | $1,803,336 | $1,797,692 | $1,792,048 | $1,786,404 | $1,780,760 | $1,775,116 | $1,769,472 | |
| 6 | Average Net Investment | | $1,834,378 | $1,828,734 | $1,823,090 | $1,817,446 | $1,811,802 | $1,806,158 | $1,800,514 | $1,794,870 | $1,789,226 | $1,783,582 | $1,777,938 | $1,772,294 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 3,098 | 3,087 | 3,078 | 3,069 | 3,059 | 3,050 | 3,040 | 3,031 | 3,021 | 3,012 | 3,002 | 2,994 | 36,541 |
| | b. Equity Component Grossed Up For Taxes | | 12,742 | 12,701 | 12,663 | 12,624 | 12,584 | 12,544 | 12,507 | 12,466 | 12,428 | 12,388 | 12,349 | 12,311 | 150,307 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 5,644 | 67,728 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 2,107 | 25,284 |
| | e. Other (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $23,591 | $23,539 | $23,492 | $23,444 | $23,394 | $23,345 | $23,298 | $23,248 | $23,200 | $23,151 | $23,102 | $23,056 | $279,860 |
| 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) | | 17,151 | 17,114 | 17,079 | 17,044 | 17,008 | 16,973 | 16,938 | 16,902 | 16,867 | 16,831 | 16,796 | 16,762 | 203,467 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $17,151 | $17,114 | $17,079 | $17,044 | $17,008 | $16,973 | $16,938 | $16,902 | $16,867 | $16,831 | $16,796 | $16,762 | $203,467 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | $11,301,803 | |
| 3 | Less: Accumulated Depreciation | (2,805,915) | (2,839,142) | (2,872,369) | (2,905,596) | (2,938,823) | (2,972,050) | (3,005,277) | (3,038,504) | (3,071,731) | (3,104,958) | (3,138,185) | (3,171,412) | (3,204,639) | |
| 4 | CWIP - Non-Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $8,495,889 | $8,462,662 | $8,429,435 | $8,396,208 | $8,362,981 | $8,329,754 | $8,296,527 | $8,263,300 | $8,230,073 | $8,196,846 | $8,163,619 | $8,130,392 | $8,097,165 | |
| 6 | Average Net Investment | | $8,479,275 | $8,446,048 | $8,412,821 | $8,379,594 | $8,346,367 | $8,313,140 | $8,279,913 | $8,246,686 | $8,213,459 | $8,180,232 | $8,147,005 | $8,113,778 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 14,317 | 14,261 | 14,205 | 14,148 | 14,093 | 14,037 | 13,980 | 13,924 | 13,867 | 13,812 | 13,755 | 13,699 | 168,098 |
| | b. Equity Component Grossed Up For Taxes | | 58,896 | 58,664 | 58,432 | 58,204 | 57,971 | 57,740 | 57,511 | 57,280 | 57,049 | 56,818 | 56,587 | 56,356 | 691,508 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 33,227 | 398,724 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 9,917 | 119,004 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $116,357 | $116,069 | $115,781 | $115,496 | $115,208 | $114,921 | $114,635 | $114,348 | $114,060 | $113,774 | $113,486 | $113,199 | $1,377,334 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $116,357 | $116,069 | $115,781 | $115,496 | $115,208 | $114,921 | $114,635 | $114,348 | $114,060 | $113,774 | $113,486 | $113,199 | $1,377,334 |
| 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) | | 111,614 | 111,338 | 111,062 | 110,788 | 110,512 | 110,237 | 109,962 | 109,687 | 109,411 | 109,137 | 108,860 | 108,585 | 1,321,194 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $111,614 | $111,338 | $111,062 | $110,788 | $110,512 | $110,237 | $109,962 | $109,687 | $109,411 | $109,137 | $108,860 | $108,585 | $1,321,194 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | 100,001 | 96,969 | 93,937 | 90,905 | 87,873 | 84,841 | 81,809 | 78,777 | 75,745 | 72,713 | 69,681 | 66,649 | 63,617 | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | $2,499,040 | $2,496,008 | $2,492,976 | $2,489,944 | $2,486,912 | $2,483,880 | $2,480,848 | $2,477,816 | $2,474,784 | $2,471,752 | $2,468,720 | $2,465,688 | $2,462,656 | |
| 6 | Average Net Investment | | $2,497,524 | $2,494,492 | $2,491,460 | $2,488,428 | $2,485,396 | $2,482,364 | $2,479,332 | $2,476,300 | $2,473,268 | $2,470,236 | $2,467,204 | $2,464,172 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 4,217 | 4,212 | 4,207 | 4,201 | 4,196 | 4,191 | 4,186 | 4,181 | 4,177 | 4,171 | 4,166 | 4,161 | 50,266 |
| | b. Equity Component Grossed Up For Taxes | | 17,347 | 17,326 | 17,305 | 17,284 | 17,263 | 17,242 | 17,221 | 17,200 | 17,178 | 17,158 | 17,137 | 17,115 | 206,776 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 3,032 | 36,384 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 4,092 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $24,937 | $24,911 | $24,885 | $24,858 | $24,832 | $24,806 | $24,780 | $24,754 | $24,728 | $24,702 | $24,676 | $24,649 | $297,518 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $24,937 | $24,911 | $24,885 | $24,858 | $24,832 | $24,806 | $24,780 | $24,754 | $24,728 | $24,702 | $24,676 | $24,649 | $297,518 |
| 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) | | 23,163 | 23,139 | 23,114 | 23,089 | 23,065 | 23,041 | 23,017 | 22,993 | 22,969 | 22,944 | 22,920 | 22,895 | 276,350 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $23,163 | $23,139 | $23,114 | $23,089 | $23,065 | $23,041 | $23,017 | $22,993 | $22,969 | $22,944 | $22,920 | $22,895 | $276,350 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | (60,186) | (60,711) | (61,236) | (61,761) | (62,286) | (62,811) | (63,336) | (63,861) | (64,386) | (64,911) | (65,436) | (65,961) | (66,486) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2+ 3 + 4) | $230,112 | $229,587 | $229,062 | $228,537 | $228,012 | $227,487 | $226,962 | $226,437 | $225,912 | $225,387 | $224,862 | $224,337 | $223,812 | |
| 6 | Average Net Investment | | $229,849 | $229,324 | $228,799 | $228,274 | $227,749 | $227,224 | $226,699 | $226,174 | $225,649 | $225,124 | $224,599 | $224,074 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 388 | 387 | 386 | 385 | 385 | 384 | 383 | 382 | 381 | 380 | 379 | 378 | 4,598 |
| | b. Equity Component Grossed Up For Taxes | | 1,596 | 1,593 | 1,589 | 1,586 | 1,582 | 1,578 | 1,575 | 1,571 | 1,567 | 1,564 | 1,560 | 1,556 | 18,917 |
| | 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) | | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 191 | 2,292 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $2,700 | $2,696 | $2,691 | $2,687 | $2,683 | $2,678 | $2,674 | $2,669 | $2,664 | $2,660 | $2,655 | $2,650 | $32,107 |
| 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) | | 1,963 | 1,960 | 1,956 | 1,954 | 1,951 | 1,947 | 1,944 | 1,940 | 1,937 | 1,934 | 1,930 | 1,927 | 23,343 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $1,963 | $1,960 | $1,956 | $1,954 | $1,951 | $1,947 | $1,944 | $1,940 | $1,937 | $1,934 | $1,930 | $1,927 | $23,343 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0158150 $SO_2$ Emission Allowance Inventory | | $3,333,608 | $3,324,785 | $3,315,961 | $3,304,982 | $3,296,584 | $3,287,013 | $3,277,343 | $3,267,414 | $3,257,471 | $3,247,532 | $3,238,730 | $3,230,982 | $3,222,750 | $3,222,750 |
| | b. 0254020 Auctioned $SO_2$ Allowance | | (4,039) | (4,039) | (4,039) | (4,039) | (4,298) | (4,289) | (4,281) | (4,272) | (4,264) | (4,256) | (4,247) | (4,239) | (4,230) | (4,230) |
| | c. 0158170 NOx Emission Allowance Inventory | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Other (A) | | 7,258,313 | 6,955,883 | 6,653,453 | 6,351,024 | 6,048,594 | 5,746,164 | 5,443,735 | 5,141,305 | 4,838,875 | 4,536,446 | 4,234,016 | 3,931,586 | 3,629,156 | 3,629,156 |
| 2 | Total Working Capital | | $10,587,882 | $10,276,629 | $9,965,375 | $9,651,967 | $9,340,880 | $9,028,888 | $8,716,797 | $8,404,447 | $8,092,083 | $7,779,722 | $7,468,499 | $7,158,329 | $6,847,676 | $6,847,676 |
| 3 | Average Net Investment | | | $10,432,255 | $10,121,002 | $9,808,671 | $9,496,424 | $9,184,884 | $8,872,843 | $8,560,622 | $8,248,265 | $7,935,902 | $7,624,110 | $7,313,414 | $7,003,003 | |
| 4 | Return on Average Net Working Capital Balance (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 17,615 | 17,089 | 16,562 | 16,035 | 15,509 | 14,982 | 14,455 | 13,927 | 13,400 | 12,873 | 12,349 | 11,825 | 176,621 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 72,460 | 70,298 | 68,128 | 65,960 | 63,796 | 61,628 | 59,460 | 57,290 | 55,121 | 52,955 | 50,797 | 48,641 | 726,534 |
| 5 | Total Return Component (C) | | | $90,075 | $87,387 | $84,690 | $81,995 | $79,305 | $76,610 | $73,915 | $71,217 | $68,521 | $65,828 | $63,146 | $60,466 | 903,155 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0509030 $SO_2$ Allowance Expense | | | $8,824 | $8,824 | $10,978 | $8,399 | $9,571 | $9,670 | $9,929 | $9,943 | $9,940 | $8,802 | $7,748 | $8,232 | 110,858 |
| | b. 0407426 Amortization Expense | | | 0 | 0 | 0 | 259 | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | 191 |
| | 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) | | | 8,824 | 8,824 | 10,978 | 8,657 | 9,562 | 9,661 | 9,921 | 9,934 | 9,931 | 8,793 | 7,740 | 8,223 | 111,050 |
| 8 | Amortization of NOx CAIR Emission Allowances (A) | | | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | $302,430 | 3,629,156 |
| 9 | Total System Recoverable Expenses (Lines 5 + 7) | | | $401,328 | $398,641 | $398,098 | $393,082 | $391,297 | $388,701 | $386,265 | $383,581 | $380,882 | $377,051 | $373,316 | $371,119 | |
| | a. Recoverable Costs Allocated to Energy | | | 98,899 | 96,211 | 95,668 | 90,652 | 88,867 | 86,271 | 83,836 | 81,151 | 78,452 | 74,621 | 70,886 | 68,689 | |
| | b. Recoverable Costs Allocated to Energy - NOx CAIR Emisssion Allowances (A) | | | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | 302,430 | |
| 10 | a. Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| | b. NOx Regulatory Asset Energy Factor (12/2014) (A) | | | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | 0.97930 | |
| 11 | Retail Energy-Related Recoverable Costs (E) | | | $96,749 | $93,945 | $94,065 | $88,654 | $86,381 | $83,733 | $81,117 | $78,314 | $75,828 | $72,159 | $68,523 | $67,091 | 986,559 |
| 12 | Retail Demand-Related Recoverable Costs (F) | | | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 296,169 | 3,554,033 |
| 13 | Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | | $ 392,918 | $ 390,114 | $ 390,235 | $ 384,824 | $ 382,550 | $ 379,903 | $ 377,287 | $ 374,483 | $ 371,997 | $ 368,329 | $ 364,692 | $ 363,260 | $ 4,540,592 |

Notes:

(A) Unusable NOx emission allowances due expiration of Clean Air Interstate Rule (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 conisistent with Order No. PSC-11-0553-FOF-EI.

(B) Line 3 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.

(C) Line 5 is reported on Capital Schedule

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

(E) Line 9a x Line 10a

(F) Line 9b x Line 10b

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | $1,936,108 | |
| 3 | Less: Accumulated Depreciation | (346,416) | (349,966) | (353,516) | (357,066) | (360,616) | (364,166) | (367,716) | (371,266) | (374,816) | (378,366) | (381,916) | (385,466) | (389,016) | |
| 4 | CWIP - Non-Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $1,589,692 | $1,586,142 | $1,582,592 | $1,579,042 | $1,575,492 | $1,571,942 | $1,568,392 | $1,564,842 | $1,561,292 | $1,557,742 | $1,554,192 | $1,550,642 | $1,547,092 | |
| 6 | Average Net Investment | | $1,587,917 | $1,584,367 | $1,580,817 | $1,577,267 | $1,573,717 | $1,570,167 | $1,566,617 | $1,563,067 | $1,559,517 | $1,555,967 | $1,552,417 | $1,548,867 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 2,680 | 2,675 | 2,670 | 2,662 | 2,658 | 2,651 | 2,646 | 2,639 | 2,632 | 2,629 | 2,621 | 2,614 | 31,777 |
| | b. Equity Component Grossed Up For Taxes | | 11,029 | 11,005 | 10,980 | 10,954 | 10,931 | 10,905 | 10,881 | 10,856 | 10,831 | 10,807 | 10,783 | 10,759 | 130,721 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 3,550 | 42,600 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | N/A |
| | d. Property Taxes (D) | | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 1,545 | 18,540 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $18,804 | $18,775 | $18,745 | $18,711 | $18,684 | $18,651 | $18,622 | $18,590 | $18,558 | $18,531 | $18,499 | $18,468 | 223,638 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $18,804 | $18,775 | $18,745 | $18,711 | $18,684 | $18,651 | $18,622 | $18,590 | $18,558 | $18,531 | $18,499 | $18,468 | 223,638 |
| 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) | | 18,038 | 18,010 | 17,981 | 17,948 | 17,922 | 17,891 | 17,863 | 17,832 | 17,802 | 17,776 | 17,745 | 17,715 | 214,523 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $18,038 | $18,010 | $17,981 | $17,948 | $17,922 | $17,891 | $17,863 | $17,832 | $17,802 | $17,776 | $17,745 | $17,715 | $214,523 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
Page 11 of 45

**Return on Capital Investments, Depreciation and Taxes**
**For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)**
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $59,427 | $713,122 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 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 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | $3,950,867 | |
| 3 | Less: Accumulated Depreciation | (106,469) | (114,097) | (121,725) | (129,353) | (136,981) | (144,609) | (152,237) | (159,865) | (167,493) | (175,121) | (182,749) | (190,377) | (198,005) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 59,427 | 118,854 | 178,281 | 237,707 | 297,134 | 356,561 | 415,988 | 475,415 | 534,842 | 594,268 | 653,695 | 713,122 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $3,844,399 | $3,896,197 | $3,947,996 | $3,999,795 | $4,051,594 | $4,103,393 | $4,155,192 | $4,206,990 | $4,258,789 | $4,310,588 | $4,362,387 | $4,414,186 | $4,465,985 | |
| 6 | Average Net Investment | | $3,870,298 | $3,922,097 | $3,973,896 | $4,025,694 | $4,077,493 | $4,129,292 | $4,181,091 | $4,232,890 | $4,284,689 | $4,336,487 | $4,388,286 | $4,440,085 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component | | 6,649 | 6,850 | 6,938 | 7,026 | 7,114 | 7,199 | 7,288 | 7,376 | 7,462 | 7,550 | 7,638 | 7,725 | 86,815 |
| | b. Equity Component Grossed Up For Taxes | | 27,352 | 28,180 | 28,539 | 28,900 | 29,260 | 29,619 | 29,979 | 30,339 | 30,697 | 31,058 | 31,419 | 31,778 | 357,120 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 7,628 | 91,536 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (D) | | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 561 | 6,732 |
| | e. Other | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | $42,190 | $43,219 | $43,666 | $44,115 | $44,563 | $45,007 | $45,456 | $45,904 | $46,348 | $46,797 | $47,246 | $47,692 | 542,203 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $42,190 | $43,219 | $43,666 | $44,115 | $44,563 | $45,007 | $45,456 | $45,904 | $46,348 | $46,797 | $47,246 | $47,692 | 542,203 |
| 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) | | 39,188 | 40,144 | 40,559 | 40,976 | 41,392 | 41,805 | 42,222 | 42,638 | 43,050 | 43,467 | 43,884 | 44,299 | 503,625 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $39,188 | $40,144 | $40,559 | $40,976 | $41,392 | $41,805 | $42,222 | $42,638 | $43,050 | $43,467 | $43,884 | $44,299 | $503,625 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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-10-0131-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**Schedule of Amortization and Return**
**For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-Products)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0154401 Ammonia Inventory | | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | $185,206 | 185,206 |
| | b. 0154200 Limestone Inventory | | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 | 900,036 |
| 2 | Total Working Capital | | $1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 |
| 3 | Average Net Investment | | | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | 1,085,242 | |
| 4 | Return on Average Net Working Capital Balance (A) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | 1,832 | $21,989 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 7,538 | 90,454 |
| 5 | Total Return Component (B) | | | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 9,370 | 112,443 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0502010 Ammonia Expense | | | 455,485 | 425,538 | 297,964 | 432,747 | 455,824 | 459,359 | 470,739 | 467,246 | 474,561 | 484,937 | 413,592 | 472,009 | 5,310,002 |
| | b. 0502040 Limestone Expense | | | 447,356 | 418,943 | 294,169 | 428,890 | 452,848 | 457,804 | 470,373 | 468,108 | 476,919 | 488,404 | 417,340 | 476,024 | 5,297,179 |
| | c. 0502050 Dibasic Acid Expense | | | 0 | 0 | 22,000 | 0 | 0 | 22,000 | 0 | 22,000 | 0 | 0 | 0 | 22,000 | 88,000 |
| | d. 0502070 Gypsum Disposal/Sale | | | 101,740 | 99,311 | 99,311 | 123,599 | 102,010 | 106,867 | 85,008 | 99,311 | 99,311 | 99,311 | 99,311 | 99,311 | 1,214,400 |
| | e. 0502040 Hydrated Lime Expense | | | 392,243 | 367,696 | 263,483 | 371,906 | 391,298 | 394,918 | 404,935 | 401,472 | 407,628 | 416,522 | 356,548 | 405,595 | 4,574,245 |
| | f. 0502300 Caustic Expense | | | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 25,000 | 300,000 |
| 7 | Net Expense (C) | | | 1,421,824 | 1,336,488 | 1,001,927 | 1,382,142 | 1,426,980 | 1,465,949 | 1,456,055 | 1,483,137 | 1,483,419 | 1,514,175 | 1,311,791 | 1,499,939 | 16,783,826 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | | $1,431,194 | $1,345,858 | $1,011,298 | $1,391,513 | $1,436,350 | $1,475,319 | $1,465,425 | $1,492,507 | $1,492,790 | $1,523,545 | $1,321,161 | $1,509,309 | $16,896,268 |
| | a. Recoverable Costs Allocated to Energy | | | 1,431,194 | 1,345,858 | 1,011,298 | 1,391,513 | 1,436,350 | 1,475,319 | 1,465,425 | 1,492,507 | 1,492,790 | 1,523,545 | 1,321,161 | 1,509,309 | 16,896,268 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | 1,400,082 | 1,314,159 | 994,353 | 1,360,849 | 1,396,157 | 1,431,917 | 1,417,906 | 1,440,318 | 1,442,847 | 1,473,276 | 1,277,119 | 1,474,184 | 16,423,168 |
| 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) | | | $ 1,400,082 | $ 1,314,159 | $ 994,353 | $ 1,360,849 | $ 1,396,157 | $ 1,431,917 | $ 1,417,906 | $ 1,440,318 | $ 1,442,847 | $ 1,473,276 | $ 1,277,119 | $ 1,474,184 | $ 16,423,168 |

Notes:

(A) Line 3 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $150 | $150 | $150 | $150 | $150 | $0 | $0 | $0 | $750 |
| | b. Clearings to Plant | | 300 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 750 | 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 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 11,624 | 12,374 | 12,374 | 12,374 | 12,374 | |
| 3 | Less: Accumulated Depreciation | (2,655) | (2,684) | (2,714) | (2,744) | (2,774) | (2,804) | (2,834) | (2,864) | (2,894) | (2,924) | (2,956) | (2,988) | (3,020) | |
| 4 | CWIP - Non-Interest Bearing | 300 | 0 | 0 | 0 | 0 | 150 | 300 | 450 | 600 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $8,969 | $8,940 | $8,910 | $8,880 | $8,850 | $8,970 | $9,090 | $9,210 | $9,330 | $9,450 | $9,418 | $9,386 | $9,354 | |
| 6 | Average Net Investment | | $8,954 | $8,925 | $8,895 | $8,865 | $8,910 | $9,030 | $9,150 | $9,270 | $9,390 | $9,434 | $9,402 | $9,370 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | |
| | a. Debt Component 2.03% | | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 16 | 16 | 16 | 16 | 16 | 185 |
| | b. Equity Component Grossed Up For Taxes 8.33% | | 62 | 62 | 62 | 62 | 62 | 63 | 64 | 64 | 65 | 66 | 65 | 65 | 762 |
| | c. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) 3.0658% | | 29 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 32 | 32 | 32 | 365 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/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) 0.009035 | | 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) | | $115 | $116 | $116 | $116 | $116 | $117 | $118 | $119 | $120 | $123 | $122 | $122 | 1,420 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | $115 | $116 | $116 | $116 | $116 | $117 | $118 | $119 | $120 | $123 | $122 | $122 | 1,420 |
| 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) | | 114 | 115 | 115 | 115 | 115 | 116 | 117 | 118 | 119 | 122 | 121 | 121 | 1,414 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $114 | $115 | $115 | $115 | $115 | $116 | $117 | $118 | $119 | $122 | $121 | $121 | $1,414 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | (35,344) | (35,640) | (35,936) | (36,232) | (36,528) | (36,824) | (37,120) | (37,416) | (37,712) | (38,008) | (38,304) | (38,600) | (38,896) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $133,597 | $133,301 | $133,005 | $132,709 | $132,413 | $132,117 | $131,821 | $131,525 | $131,229 | $130,933 | $130,637 | $130,341 | $130,045 | |
| 6 | Average Net Investment | | | $133,449 | $133,153 | $132,857 | $132,561 | $132,265 | $131,969 | $131,673 | $131,377 | $131,081 | $130,785 | $130,489 | $130,193 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 225 | 225 | 224 | 224 | 223 | 223 | 222 | 222 | 221 | 221 | 220 | 220 | 2,670 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 927 | 925 | 923 | 921 | 919 | 917 | 915 | 913 | 910 | 908 | 906 | 904 | 10,988 |
| | 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) | | | $1,569 | $1,567 | $1,564 | $1,562 | $1,559 | $1,557 | $1,554 | $1,552 | $1,548 | $1,546 | $1,543 | $1,541 | 18,662 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $1,569 | $1,567 | $1,564 | $1,562 | $1,559 | $1,557 | $1,554 | $1,552 | $1,548 | $1,546 | $1,543 | $1,541 | 18,662 |
| 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) | | | 1,457 | 1,456 | 1,453 | 1,451 | 1,448 | 1,446 | 1,443 | 1,442 | 1,438 | 1,436 | 1,433 | 1,431 | 17,334 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $1,457 | $1,456 | $1,453 | $1,451 | $1,448 | $1,446 | $1,443 | $1,442 | $1,438 | $1,436 | $1,433 | $1,431 | $17,334 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | (21,785) | (21,988) | (22,191) | (22,394) | (22,597) | (22,800) | (23,003) | (23,206) | (23,409) | (23,612) | (23,815) | (24,018) | (24,221) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $54,221 | $54,018 | $53,815 | $53,612 | $53,409 | $53,206 | $53,003 | $52,800 | $52,597 | $52,394 | $52,191 | $51,988 | $51,785 | |
| 6 | Average Net Investment | | | $54,120 | $53,917 | $53,714 | $53,511 | $53,308 | $53,105 | $52,902 | $52,699 | $52,496 | $52,293 | $52,090 | $51,887 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 91 | 91 | 91 | 90 | 90 | 90 | 89 | 89 | 89 | 88 | 88 | 88 | 1,074 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 376 | 374 | 373 | 372 | 370 | 369 | 367 | 366 | 365 | 363 | 362 | 360 | 4,417 |
| | 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) | | | $733 | $731 | $730 | $728 | $726 | $725 | $722 | $721 | $720 | $717 | $716 | $714 | 8,683 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $733 | $731 | $730 | $728 | $726 | $725 | $722 | $721 | $720 | $717 | $716 | $714 | 8,683 |
| 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) | | | 533 | 531 | 531 | 529 | 528 | 527 | 525 | 524 | 523 | 521 | 521 | 519 | 6,313 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $533 | $531 | $531 | $529 | $528 | $527 | $525 | $524 | $523 | $521 | $521 | $519 | $6,313 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | 12,922,573 | |
| 3 | Less: Accumulated Depreciation | | (431,137) | (467,033) | (502,929) | (538,825) | (574,721) | (610,617) | (646,513) | (682,409) | (718,305) | (754,201) | (790,097) | (825,993) | (861,889) | |
| 4 | CWIP - Non-Interest Bearing | | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | (28,062) | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $12,463,374 | $12,427,478 | $12,391,582 | $12,355,686 | $12,319,790 | $12,283,894 | $12,247,998 | $12,212,102 | $12,176,206 | $12,140,310 | $12,104,414 | $12,068,518 | $12,032,622 | |
| 6 | Average Net Investment | | | $12,445,426 | $12,409,530 | $12,373,634 | $12,337,738 | $12,301,842 | $12,265,946 | $12,230,050 | $12,194,154 | $12,158,258 | $12,122,362 | $12,086,466 | $12,050,570 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 21,014 | 20,953 | 20,893 | 20,832 | 20,772 | 20,711 | 20,650 | 20,590 | 20,529 | 20,469 | 20,408 | 20,347 | 248,168 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 86,443 | 86,193 | 85,944 | 85,695 | 85,445 | 85,196 | 84,947 | 84,697 | 84,448 | 84,199 | 83,949 | 83,700 | 1,020,856 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.3333% | | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 35,896 | 430,752 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (D) | 0.009890 | | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 10,650 | 127,800 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $154,003 | $153,692 | $153,383 | $153,073 | $152,763 | $152,453 | $152,143 | $151,833 | $151,523 | $151,214 | $150,903 | $150,593 | 1,827,576 |
| | 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 | | | $154,003 | $153,692 | $153,383 | $153,073 | $152,763 | $152,453 | $152,143 | $151,833 | $151,523 | $151,214 | $150,903 | $150,593 | 1,827,576 |
| 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 - 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) | | | 111,965 | 111,739 | 111,514 | 111,289 | 111,063 | 110,838 | 110,613 | 110,387 | 110,162 | 109,937 | 109,711 | 109,486 | 1,328,703 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $111,965 | $111,739 | $111,514 | $111,289 | $111,063 | $110,838 | $110,613 | $110,387 | $110,162 | $109,937 | $109,711 | $109,486 | $1,328,703 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 1
(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 2014 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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | 3,664,943 | |
| 3 | Less: Accumulated Depreciation | | (47,336) | (53,873) | (60,411) | (66,948) | (73,486) | (80,023) | (86,561) | (93,098) | (99,636) | (106,173) | (112,710) | (119,248) | (125,785) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $3,617,607 | $3,611,069 | $3,604,532 | $3,597,994 | $3,591,457 | $3,584,919 | $3,578,382 | $3,571,845 | $3,565,307 | $3,558,770 | $3,552,232 | $3,545,695 | $3,539,157 | |
| 6 | Average Net Investment | | | $3,614,338 | $3,607,801 | $3,601,263 | $3,594,726 | $3,588,188 | $3,581,651 | $3,575,113 | $3,568,576 | $3,562,038 | $3,555,501 | $3,548,963 | $3,542,426 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 6,103 | 6,092 | 6,081 | 6,070 | 6,059 | 6,048 | 6,037 | 6,026 | 6,015 | 6,003 | 5,992 | 5,981 | 72,507 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 25,104 | 25,059 | 25,013 | 24,968 | 24,923 | 24,877 | 24,832 | 24,786 | 24,741 | 24,696 | 24,650 | 24,605 | 298,254 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | Blended | | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 6,537 | 78,449 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 520 | 6,241 |
| | 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) | | | $37,668 | $37,612 | $37,555 | $37,499 | $37,443 | $37,386 | $37,330 | $37,273 | $37,217 | $37,160 | $37,103 | $37,047 | 448,291 |
| | a. Recoverable Costs Allocated to Energy | | | 37,668 | 37,612 | 37,555 | 37,499 | 37,443 | 37,386 | 37,330 | 37,273 | 37,217 | 37,160 | 37,103 | 37,047 | 448,291 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $36,849 | $36,726 | $36,926 | $36,673 | $36,395 | $36,286 | $36,119 | $35,970 | $35,972 | $35,934 | $35,866 | $36,185 | $435,901 |
| 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) | | | $36,849 | $36,726 | $36,926 | $36,673 | $36,395 | $36,286 | $36,119 | $35,970 | $35,972 | $35,934 | $35,866 | $36,185 | $435,901 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-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 2016 - December 2016**

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | 134,750,275 | |
| 3 | Less: Accumulated Depreciation | | (5,824,679) | (6,068,599) | (6,312,519) | (6,556,439) | (6,800,359) | (7,044,279) | (7,288,199) | (7,532,119) | (7,776,039) | (8,019,959) | (8,263,879) | (8,507,799) | (8,751,719) | |
| 4 | CWIP - AFUDC Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $128,925,596 | $128,681,676 | $128,437,756 | $128,193,836 | $127,949,916 | $127,705,996 | $127,462,076 | $127,218,156 | $126,974,236 | $126,730,316 | $126,486,396 | $126,242,476 | $125,998,556 | |
| 6 | Average Net Investment | | | $128,803,636 | $128,559,716 | $128,315,796 | $128,071,876 | $127,827,956 | $127,584,036 | $127,340,116 | $127,096,196 | $126,852,276 | $126,608,356 | $126,364,436 | $126,120,516 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 217,485 | 217,073 | 216,661 | 216,249 | 215,838 | 215,426 | 215,014 | 214,602 | 214,190 | 213,778 | 213,366 | 212,954 | 2,582,636 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 894,636 | 892,941 | 891,247 | 889,553 | 887,859 | 886,165 | 884,470 | 882,776 | 881,082 | 879,388 | 877,694 | 875,999 | 10,623,810 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.1722% | | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 243,920 | 2,927,040 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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) | 0.007910 | | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 88,823 | 1,065,876 |
| | 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) | | | $1,430,070 | $1,427,963 | $1,425,857 | $1,423,751 | $1,421,646 | $1,419,540 | $1,417,433 | $1,415,327 | $1,413,221 | $1,411,115 | $1,409,009 | $1,406,902 | 17,021,828 |
| | a. Recoverable Costs Allocated to Energy | | | 1,430,070 | 1,427,963 | 1,425,857 | 1,423,751 | 1,421,646 | 1,419,540 | 1,417,433 | 1,415,327 | 1,413,221 | 1,411,115 | 1,409,009 | 1,406,902 | 17,021,828 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $1,398,982 | $1,394,329 | $1,401,967 | $1,392,377 | $1,381,864 | $1,377,778 | $1,371,470 | $1,365,837 | $1,365,940 | $1,364,555 | $1,362,038 | $1,374,159 | $16,551,296 |
| 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) | | | $1,398,982 | $1,394,329 | $1,401,967 | $1,392,377 | $1,381,864 | $1,377,778 | $1,371,470 | $1,365,837 | $1,365,940 | $1,364,555 | $1,362,038 | $1,374,159 | $16,551,296 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**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-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $600,000 | $600,000 | $1,000,000 | $300,000 | $100,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,600,000 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 4,965,495 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | (194,715) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $20,070,225 | 20,070,225 | 20,070,225 | 20,070,225 | 20,070,225 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | 25,035,719 | |
| 3 | Less: Accumulated Depreciation | | (491,482) | (553,365) | (615,248) | (677,131) | (739,014) | (800,897) | (878,090) | (955,283) | (1,032,476) | (1,109,669) | (1,186,862) | (1,264,055) | (1,341,248) | |
| 4 | CWIP - Non-Interest Bearing | | 2,560,209 | 2,965,495 | 3,565,495 | 4,565,495 | 4,865,495 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $22,138,952 | $22,482,354 | $23,020,471 | $23,958,588 | $24,196,705 | $24,234,822 | $24,157,629 | $24,080,436 | $24,003,243 | $23,926,050 | $23,848,857 | $23,771,664 | $23,694,471 | |
| 6 | Average Net Investment | | | $22,310,653 | $22,751,413 | $23,489,530 | $24,077,647 | $24,215,764 | $24,196,226 | $24,119,033 | $24,041,840 | $23,964,647 | $23,887,454 | $23,810,261 | $23,733,068 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 37,672 | 38,416 | 39,662 | 40,655 | 40,888 | 40,855 | 40,725 | 40,595 | 40,464 | 40,334 | 40,204 | 40,073 | 480,543 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 154,964 | 158,025 | 163,152 | 167,237 | 168,196 | 168,061 | 167,524 | 166,988 | 166,452 | 165,916 | 165,380 | 164,844 | 1,976,739 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.7000% | | 61,883 | 61,883 | 61,883 | 61,883 | 61,883 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 77,193 | 849,766 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | | 2,848 | 2,848 | 2,848 | 2,848 | 2,848 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 3,553 | 39,111 |
| | 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) | | | $246,827 | $250,632 | $257,005 | $262,083 | $263,275 | $279,122 | $278,455 | $277,789 | $277,122 | $276,456 | $275,790 | $275,123 | 3,219,684 |
| | a. Recoverable Costs Allocated to Energy | | | 246,827 | 250,632 | 257,005 | 262,083 | 263,275 | 279,122 | 278,455 | 277,789 | 277,122 | 276,456 | 275,790 | 275,123 | 3,219,684 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | |
| 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) | | | $241,462 | $244,729 | $252,699 | $256,308 | $255,908 | $270,911 | $269,426 | $268,076 | $267,851 | $267,335 | $266,597 | $268,720 | $3,130,022 |
| 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) | | | $241,462 | $244,729 | $252,699 | $256,308 | $255,908 | $270,911 | $269,426 | $268,076 | $267,851 | $267,335 | $266,597 | $268,720 | $3,130,022 |

Notes:

(A) N/A
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 990007-EI, Order No. PSC-99-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 150007-EI
Duke Energy Florida, LLC
Witness: T. G. Foster
Exh. No. __ (TGF-5)
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**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Return on Capital Investments, Depreciation and Taxes**
**For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Energy (Project 18)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-16 | Estimated Feb-16 | Estimated Mar-16 | Estimated Apr-16 | Estimated May-16 | Estimated Jun-16 | Estimated Jul-16 | Estimated Aug-16 | Estimated Sep-16 | Estimated Oct-16 | Estimated Nov-16 | Estimated Dec-16 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $355,800 | $150,000 | $150,000 | $3,858,000 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,058,000 | 0 | 1,800,000 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | (1,600,000) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $1,600,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,058,000 | 2,058,000 | 3,858,000 | |
| 3 | Less: Accumulated Depreciation (A) | | (7,204) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (4,236) | (8,472) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 355,800 | 711,600 | 1,067,400 | 1,423,200 | 1,779,000 | 2,134,800 | 2,490,600 | 2,846,400 | 3,202,200 | 1,500,000 | 1,650,000 | 0 | |
| 5 | Net Investment (Lines 2 + 3 ) | | $1,592,796 | $355,800 | $711,600 | $1,067,400 | $1,423,200 | $1,779,000 | $2,134,800 | $2,490,600 | $2,846,400 | $3,202,200 | $3,558,000 | $3,703,764 | $3,849,528 | |
| 6 | Average Net Investment | | | $974,298 | $533,700 | $889,500 | $1,245,300 | $1,601,100 | $1,956,900 | $2,312,700 | $2,668,500 | $3,024,300 | $3,380,100 | $3,630,882 | $3,776,646 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 2.03% | | 1,645 | 901 | 1,502 | 2,103 | 2,703 | 3,304 | 3,905 | 4,506 | 5,107 | 5,707 | 6,131 | 6,377 | 43,891 |
| | b. Equity Component Grossed Up For Taxes | 8.33% | | 6,767 | 3,707 | 6,178 | 8,650 | 11,121 | 13,592 | 16,063 | 18,535 | 21,006 | 23,477 | 25,219 | 26,232 | 180,547 |
| | c. Other (A) | | | (56,879) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (56,879) |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 2.4700% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4,236 | 4,236 | 8,472 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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 | 292 | 292 | 584 |
| | e. Other (A) | | | (7,700) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (7,700) |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | ($56,167) | $4,608 | $7,680 | $10,753 | $13,824 | $16,896 | $19,968 | $23,041 | $26,113 | $29,184 | $35,878 | $37,137 | 168,915 | |
| | a. Recoverable Costs Allocated to Energy | | (56,167) | 4,608 | 7,680 | 10,753 | 13,824 | 16,896 | 19,968 | 23,041 | 26,113 | 29,184 | 35,878 | 37,137 | 168,915 | |
| | b. Recoverable Costs Allocated to Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.97826 | 0.97645 | 0.98325 | 0.97796 | 0.97202 | 0.97058 | 0.96757 | 0.96503 | 0.96654 | 0.96701 | 0.96666 | 0.97673 | | |
| 11 | Demand Jurisdictional Factor | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | ($54,946) | $4,499 | $7,551 | $10,516 | $13,437 | $16,399 | $19,321 | $22,235 | $25,239 | $28,221 | $34,682 | $36,273 | $163,427 | |
| 13 | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | ($54,946) | $4,499 | $7,551 | $10,516 | $13,437 | $16,399 | $19,321 | $22,235 | $25,239 | $28,221 | $34,682 | $36,273 | $163,427 | |

Notes:

(A) As explained in the testimony of Garry Miller, DEF has revised the permanent dust mitigation in-service date from October 2015 to October 2016 and determined vegetation management compliance can be achived without the 2015 capital investment. As a result, DEF has made these adjustments to ensure that the revenue requirement impact to customers is neutral.
(B) Line 6 x 10.36% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 5.12% and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU Docket No. 120007-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 2014 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 2nd Qtr end 2015, a total of 260 substation remediations are completed out of 279 slated for clean-up. DEF expects to remediate 3 more substations during the remainder of 2015.

**Project Fiscal Expenditures:**
2015 expenditures are estimated to be $405k lower than originally projected due to remediation work delays at the Consolidated Rock, Holder and Kenneth City substations.

**Project Progress Summary:**
DEF continues to remediate substation sites in accordance with the approved Substation Assessment and Remedial Action Plan (SARAP).

**Project Projections:**
2016 estimated expenditures are $1.1M.

**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:**
As of 2nd Qtr end 2015, there are 3 remaining Transformer Replacement and Inspection Program (TRIP) sites.

**Project Fiscal Expenditures:**
2015 expenditures are estimated to be $42k higher than originally projected due to costs to remove additional impacted soil at the three remaining sites.

**Project Progress Summary:**
This project is on schedule according to the approved Distribution System Investigation, Remediation and Pollution Prevention Program.

**Project Projections:**
2016 estimated expenditures are $3k.

**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) contains 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.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $19k higher than originally projected due to increased costs to comply with PIM regulations. No capital expenditures are estimated for 2015.

**Project Progress Summary:**
Ongoing regulatory compliance activities will continue until pipeline is sold or retired.

**Project Projections:**
2016 estimated O&M expenditures are $696k. No capital expenditures are expected in 2016.

**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 2015.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

**Project Projections:**
No project expenditures are expected in 2016.

**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 is treating its unused NOx costs as a regulatory asset amortizing it over 3 years, as approved by the Commission in Order No. PSC-11-0553-FOF-EI.

**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:**
2015 emission allowance expenditures are estimated to be $1.5M higher than originally projected due to unusable NOx emission allowances as a result of the expiration of the CAIR. CAIR was replaced by the CSAPR on 1/1/15. Consistent with Order No. PSC-11-0553-FOF-EI, DEF is treating costs associated with its unusable CAIR NOx emission allowances as a regulatory asset amortizing it over 3 years, beginning 1/1/15 until fully recovered by 12/31/17, with a return on the unamortized investment.

**Project Progress Summary:**
DEF continually evaluates the status of emission rules to maximize the cost effectiveness of its compliance strategy.

**Project Projections:**
2016 estimated expenditures are $111k. 2016 amortization of the CAIR NOx regulatory asset is approximately $3.6M.

**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.

**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 are under development to ensure compliance with all applicable requirements of the rule.

**Project Fiscal Expenditures:**
2015 project expenditures are estimated to be $43k lower than originally projected as methods used to allocate costs to analyze 316(b) compliance strategies at each affected Duke Energy station were adjusted to reflect present configurations and operations. DEF intends to implement a consistent approach across its entire fleet of regulated units to focus on full compliance with applicable 316(b) requirements through the development of facility specific strategic plans.

**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.

**Project Projections:**
2016 estimated O&M expenditures are $440k. No capital expenditures are expected in 2016.

**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 not 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)

**Project Accomplishments:**
The reclaimed water reuse system project was placed in-service in July 2015. This project will provide DEF with up to 1 1/2 million gallons per day of reclaimed water from the City of Crystal River to supplement well water use. This project has positive environmental impacts as it reduces aquifer use.

**Project Fiscal Expenditures:**
2015 estimated O&M expenditures are estimated to be $661k higher than originally projected due to a $710 decrease in CAIR Crystal River Project 7.4 - Base costs and $1.4 million increase in CAIR Crystal River Project 7.4 - Energy costs. The $710k is due to lower base routine project costs. The $1.4M is due to higher ammonia and hydrated lime costs offset by lower limestone and gypsum costs. 2015 estimated capital expenditures are expected to be $124k higher than originally projected due to a shift in spending from 2014 to 2015 in order to align with the City of Crystal River reclaimed water reuse project timeline.

**Project Progress Summary:**
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program.

**Project Projections:**
2016 estimated O&M and capital expenditures are $34.4M and $713k, 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 2015.

**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 2016.

**Project Title:** **Arsenic Groundwater Standard**
**Project No. 8**

**Project Description:**
On 1/22/01, the EPA adopted a new maximum contaminant level (MCL) for arsenic in drinking water replacing the previous standard of 0.050 mg/L (50ppb) with a new MCL of 0.010 mg/L (10ppb). 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 implications for land application and water reuse projects in Florida because the drinking water standard has been established as the groundwater standard by Rule 62-520.420(1), F.A.C. Lowering the arsenic standard will require new analytical methods for sampling groundwater at numerous DEF sites.

**Project Accomplishments:**
DEF has completed required monitoring as directed by the FDEP.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $23k higher than originally projected due to consultant costs to evaluate the source of arsenic exceedances and issue a summery report in compliance with FDEP Consent Order No. 09-3463C executed on 11/21/11. The Consent Order was issued by the FDEP for exceedance of the arsenic groundwater limit when the EPA lowered the arsenic maximum containment level from 50ppb to 10 ppb.

**Project Progress Summary:**
DEF is evaluating monitoring data and other options to achieve compliance in accordance to Consent Order.

**Project Projections:**
No project expenditures are expected in 2016.

**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:**
2015 capital expenditures are estimated to be $3k lower than originally projected. No new street lighting has been required in Franklin County, the City of Mexico Beach in Bay county or GULF County as DEF is in compliance with sea turtle ordinances. Also, the Don Cesar lighting project is delayed from 2014 to late 4th quarter 2015 due to scheduling conflicts.

**Project Progress Summary:**
DEF is on schedule with activities identified for this program.

**Project Projections:**
2016 estimated project O&M and capital expenditures are $450 and $750, 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

**Project Projections:**
No 2016 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 2015 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 2016 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. 060162-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 2015 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 180MWe 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 2016 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 2015 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 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
The mercury TMDL study concluded in 2012.

**Project Projections:**
No 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA during 2010.

**Project Projections:**
No 2016 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 2015 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA in September 2010.

**Project Projections:**
No 2016 expenditures are expected for this project.

**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 1/14/11, 2/14/11, 7/18/11,4/7/14 and 11/28/11, respectively. All facilities are required to meet new permitting conditions. In Docket No. 110007-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 thermal studies and whole effluent toxicity testing as required 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.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $54k lower than originally projected due to lower than expected 316(a) thermal study costs at the Anclote and Bartow stations. 2015 capital expenditures are expected to be $86k lower than originally projected due to a vendor reimbursement payment.

**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. DEF continues to work with FDEP to resolve the copper issue at the Suwannee station.

**Project Projections:**
2016 estimated O&M expenditures are $60k. No capital expenditures are expected in 2016.

**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-11-0553-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 the existing FGD and SCR systems as the primary MATS compliance measures. Additional monitoring and emissions reduction technologies will be installed in 2014 & 2015.

**Project Accomplishments:**
DEF installed ORP probes and particulate matter continuous emissions monitoring systems (PM CEMS) in 2014. In addition, a mercury characterization study was performed in late 2014, and temporary mercury re-emission control systems were installed in early 2015. DEF continues to monitor mercury emissions with Appendix K sorbent trap systems.

**Project Fiscal Expenditures:**
2015 O&M expenditures are estimated to be $153k higher than originally projected due to the addition of a temporary chemical injection system to control mercury emissions, and the cancellation of preliminary engineering for a fuel additive system to improve mercury oxidation. 2015 capital expenditures are expected to be $1.3M higher than originally projected driven by the installation of continuous emission monitoring systems (CEMS) for mercury monitoring, compliance demonstration and feedback to the re-emission control system.

**Project Progress Summary:**
Installation of mercury CEMS and permanent mercury re-emission control systems is scheduled in the third quarter of 2015. Certification and commissioning activities are expected to be completed by the end of the year.

**Project Projections:**
2016 estimated O&M is $529k. No capital expenditures are expected in 2016.

**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-12-0432-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:**
2015 capital expenditures are estimated to be $314k lower than originally projected due to earlier than expected completion of Unit 2 FD fan work in November 2013 versus December 2014. There are no recoverable O&M costs for this project.

**Project Progress Summary:**
This project is in-service.

**Project Projections:**
No 2016 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-14-0173-PAA-EI. DEF will make modifications to the electrostatic precipitators to improve particulate collection efficiency, as well as install reagent injection systems to reduce HCl and mercury emissions.

**Project Accomplishments:**
DEF finalized its CR1&2 MATS Compliance Plan in December 2013 and began implementation in early 2014.

**Project Fiscal Expenditures:**
2015 O&M expenditures are expected to be $51k lower than expected. Capital expenditures are estimated to be $4.2M higher than originally projected due to an additional project related to the Unit 1 electrostatic precipitator (ESP).

**Project Progress Summary:**
Implementation of the CR1&2 MATS Compliance Plan will be completed by April 2016.

**Project Projections:**
2016 estimated O&M and capital expenditures are $3.8M and $2.6M, respectively.

**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:**
DEF began defining and implementing of its CCR Rule compliance strategy.

**Project Fiscal Expenditures:**
2015 estimated O&M and capital expenditures are $391k and $1.6M, respectively.

**Project Progress Summary:**
Ash Landfill: Two engineering firms are studying Crystal River ash landfill stability and ash placement.
Temporary Gypsum Pad: Efforts are underway to address fugitive dust mitigation at the CCR gypsum stack-out.
FGD Blowdown Ponds: A definitive assessment and action plan is being developed.
Emergency Action Plan: A determination if the CCR requires an EPA for the FGD Blowdown Ponds is in process.
Vegetation Mgt & Inspection Work: More frequent mowing and inspection work is planned to comply with the CCR Rule.

**Project Projections:**
2016 estimated O&M and capital expenditures are $1.8M and $3.9M, respectively. See the August 31, 2015 direct testimony of Mr. Miller for 2015 CCR compliance strategy change.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of the Energy & Demand Allocation % by Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) Average 12CP Load Factor at Meter (%) | (2) Sales at Meter (mWh) | (3) Avg 12 CP at Meter (MW) (2)/(8784hrsx(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)/(8784hrs/(4)) | (9) mWh Sales at Source Energy Allocator (%) | (10) 12CP Demand Transmission Allocator (%) | (11) 12CP & 1/13 AD Demand Allocator (%) | (12) NCP Distribution Allocator (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | | | | | |
| **RS-1, RST-1, RSL-1, RSL-2, RSS-1** | | | | | | | | | | | | | |
| Secondary | 0.518 | 19,482,925 | 4,282.48 | 0.401 | 0.9463589 | 20,587,248 | 4,525.22 | 20,587,248 | 5,851.4 | 51.568% | 61.617% | 60.844% | 61.780% |
| **General Service Non-Demand** | | | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | | | |
| Secondary | 0.682 | 1,547,422 | 258.45 | 0.491 | 0.9463589 | 1,635,132 | 273.10 | 1,635,132 | 378.9 | 4.096% | 3.719% | 3.748% | 4.000% |
| Primary | 0.682 | 8,546 | 1.43 | 0.491 | 0.9766343 | 8,750 | 1.46 | 8,750 | 2.0 | 0.022% | 0.020% | 0.020% | 0.021% |
| Transmission | 0.682 | 3,571 | 0.60 | 0.491 | 0.9866343 | 3,619 | 0.60 | 0 | 0.0 | 0.009% | 0.008% | 0.008% | 0.000% |
| | | | | | | | | | | 4.127% | 3.747% | 3.776% | 4.021% |
| **General Service** | | | | | | | | | | | | | |
| **GS-2** Secondary | 1.000 | 161,981 | 18.44 | 1.000 | 0.9463589 | 171,162 | 19.49 | 171,162 | 19.5 | 0.429% | 0.265% | 0.278% | 0.206% |
| **General Service Demand** | | | | | | | | | | | | | |
| **GSD-1, GSDT-1** | | | | | | | | | | | | | |
| Secondary | 0.749 | 11,824,122 | 1,797.93 | 0.594 | 0.9463589 | 12,494,332 | 1,899.84 | 12,494,332 | 2,394.0 | 31.296% | 25.869% | 26.286% | 25.277% |
| Primary | 0.749 | 2,313,813 | 351.83 | 0.594 | 0.9766343 | 2,369,170 | 360.25 | 2,369,170 | 454.0 | 5.934% | 4.905% | 4.984% | 4.793% |
| Secondary Del/ Primary Mtr | 0.749 | 46,245 | 7.03 | 0.594 | 0.9766343 | 47,351 | 7.20 | 47,351 | 9.1 | 0.119% | 0.098% | 0.100% | 0.096% |
| Transm Del/ Primary Mtr | 0.749 | 1,419 | 0.22 | 0.594 | 0.9766343 | 1,453 | 0.22 | 0 | 0.0 | 0.004% | 0.003% | 0.003% | 0.000% |
| Transmission | 0.749 | 0 | 0.00 | 0.594 | 0.9866343 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| **SS-1** Primary | 1.166 | 5,602 | 0.55 | 0.093 | 0.9766343 | 5,736 | 0.56 | 5,736 | 7.0 | 0.014% | 0.008% | 0.008% | 0.074% |
| Transm Del/ Transm Mtr | 1.166 | 11,127 | 1.09 | 0.093 | 0.9866343 | 11,278 | 1.10 | 0 | 0.0 | 0.028% | 0.015% | 0.016% | 0.000% |
| Transm Del/ Primary Mtr | 1.166 | 3,474 | 0.34 | 0.093 | 0.9766343 | 3,557 | 0.35 | 0 | 0.0 | 0.009% | 0.005% | 0.005% | 0.000% |
| | | | | | | | | | | 37.404% | 30.902% | 31.403% | 30.240% |
| **Curtailable** | | | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, SS-3** | | | | | | | | | | | | | |
| Secondary | 1.305 | 0 | 0.00 | 0.456 | 0.9463589 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| Primary | 1.305 | 121,852 | 10.63 | 0.456 | 0.9766343 | 124,767 | 10.88 | 124,767 | 31.2 | 0.313% | 0.148% | 0.161% | 0.329% |
| **SS-3** Primary | 0.583 | 3,604 | 0.70 | 0.077 | 0.9766343 | 3,690 | 0.72 | 3,690 | 5.5 | 0.009% | 0.010% | 0.010% | 0.058% |
| | | | | | | | | | | 0.322% | 0.158% | 0.171% | 0.387% |
| **Interruptible** | | | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2** | | | | | | | | | | | | | |
| Secondary | 1.009 | 88,539 | 9.99 | 0.707 | 0.9463589 | 93,558 | 10.55 | 93,558 | 15.1 | 0.234% | 0.144% | 0.151% | 0.159% |
| Sec Del/Primary Mtr | 1.009 | 4,449 | 0.50 | 0.707 | 0.9766343 | 4,555 | 0.51 | 4,555 | 0.7 | 0.011% | 0.007% | 0.007% | 0.008% |
| Primary Del / Primary Mtr | 1.009 | 1,229,525 | 138.66 | 0.707 | 0.9766343 | 1,258,941 | 141.98 | 1,258,941 | 202.9 | 3.153% | 1.933% | 2.027% | 2.142% |
| Primary Del / Transm Mtr | 1.009 | 9,117 | 1.03 | 0.707 | 0.9866343 | 9,241 | 1.04 | 9,241 | 1.5 | 0.023% | 0.014% | 0.015% | 0.016% |
| Transm Del/ Transm Mtr | 1.009 | 222,224 | 25.06 | 0.707 | 0.9866343 | 225,234 | 25.40 | 0 | 0.0 | 0.564% | 0.346% | 0.363% | 0.000% |
| Transm Del/ Primary Mtr | 1.009 | 269,448 | 30.39 | 0.707 | 0.9766343 | 275,894 | 31.11 | 0 | 0.0 | 0.691% | 0.424% | 0.444% | 0.000% |
| **SS-2** Primary | 0.870 | 9,262 | 1.21 | 0.380 | 0.9766343 | 9,484 | 1.24 | 9,484 | 2.8 | 0.024% | 0.017% | 0.017% | 0.030% |
| Transm Del/ Transm Mtr | 0.870 | 92,038 | 12.05 | 0.380 | 0.9866343 | 93,285 | 12.21 | 0 | 0.0 | 0.234% | 0.166% | 0.171% | 0.000% |
| Transm Del/ Primary Mtr | 0.870 | 80,335 | 10.52 | 0.380 | 0.9766343 | 82,257 | 10.77 | 0 | 0.0 | 0.206% | 0.147% | 0.151% | 0.000% |
| | | | | | | | | | | 5.141% | 3.197% | 3.347% | 2.354% |
| **Lighting** | | | | | | | | | | | | | |
| **LS-1** (Secondary) | 5.506 | 381,551 | 7.89 | 0.479 | 0.9463589 | 403,178 | 8.34 | 403,178 | 95.8 | 1.010% | 0.114% | 0.182% | 1.012% |
| | | 37,922,191 | 6,969.01 | | | 39,922,874 | 7,344.16 | 39,226,296 | 9,471.2 | 100.000% | 100.000% | 100.000% | 100.000% |

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2015
(2) Projected kWh sales for the period January 2016 to December 2016
(3) Calculated: Column 2 / (8,784 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2015
(5) Based on system average line loss analysis for 2014
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,784 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 9 x 1/13 + Column 10 x 12/13
(12) Column 8/ Total Column 8

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) mWh Sales at Source Energy Allocator (%) | (2) 12CP Transmission Demand Allocator (%) | (3) 12CP & 1/13th AD Demand Allocator (%) | (4) NCP Distribution Allocator (%) | (5) Energy-Related Costs ($) | (6) Transmission Demand Costs ($) | (8) Production Demand Costs ($) | (7) Distribution Demand Costs ($) | (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 | 51.568% | 61.617% | 60.844% | 61.780% | $33,378,628 | $480,062 | $2,168,692 | ($164,617) | $35,862,765 | 19,482,925 | **0.184** |
| **General Service Non-Demand** | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 1,547,422 | **0.181** |
| Primary | | | | | | | | | | 8,461 | **0.179** |
| Transmission | | | | | | | | | | 3,500 | **0.177** |
| **TOTAL GS** | 4.127% | 3.747% | 3.776% | 4.021% | $2,671,137 | $29,191 | $134,590 | ($10,715) | $2,824,203 | **1,559,382** | |
| **General Service** | | | | | | | | | | | |
| **GS-2** Secondary | 0.429% | 0.265% | 0.278% | 0.206% | $277,510 | $2,067 | $9,905.12 | ($548.19) | $288,934 | 161,981 | **0.178** |
| **General Service Demand** | | | | | | | | | | | |
| **GSD-1, GSDT-1, SS-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 11,824,122 | **0.180** |
| Primary | | | | | | | | | | 2,346,847 | **0.178** |
| Transmission | | | | | | | | | | 10,904 | **0.176** |
| **TOTAL GSD** | 37.404% | 30.902% | 31.403% | 30.240% | $24,211,054 | $240,764 | $1,119,303 | ($80,575) | $25,490,546 | **14,181,874** | |
| **Curtailable** | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3** | | | | | | | | | | | |
| Secondary | | | | | | | | | | - | **0.173** |
| Primary | | | | | | | | | | 124,201 | **0.171** |
| Transmission | | | | | | | | | | - | **0.170** |
| **TOTAL CS** | 0.322% | 0.158% | 0.171% | 0.387% | $208,271 | $1,231 | $6,081 | ($1,030) | $214,553 | **124,201** | |
| **Interruptible** | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2, SS-2** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 88,539 | **0.175** |
| Primary | | | | | | | | | | 1,577,089 | **0.173** |
| Transmission | | | | | | | | | | 316,911 | **0.172** |
| **TOTAL IS** | 5.141% | 3.197% | 3.347% | 2.354% | $3,327,687 | $24,912 | $119,299 | ($6,274) | $3,465,624 | **1,982,539** | |
| **Lighting** | | | | | | | | | | | |
| **LS-1** Secondary | 1.010% | 0.114% | 0.182% | 1.012% | $653,683 | $884 | $6,503.57 | ($2,695.78) | $658,375 | 381,551 | **0.173** |
| | 100.000% | 100.000% | 100.000% | 100.000% | $64,727,970 | $779,111 | $3,564,373 | ($266,454) | $68,805,000 | 37,874,454 | **0.182** |

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 4 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
(8) Column 3 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 2016 to December 2016
(11) (Column 9/ Column 10)/10

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2016 - December 2016**

**Capital Structure and Cost Rates**



| Class of Capital | | Retail Amount | Ratio | Cost Rate | Weighted Cost Rate | PreTax Weighted Cost Rate |
|---|---|---|---|---|---|---|
| CE | $ | 4,681,853 | 48.76% | 0.10500 | 5.120% | 8.335% |
| PS | | - | 0.00% | 0.00000 | 0.000% | 0.000% |
| LTD | | 3,672,596 | 38.25% | 0.05187 | 1.984% | 1.984% |
| STD | | (90,568) | -0.94% | 0.00170 | -0.002% | -0.002% |
| CD-Active | | 182,163 | 1.90% | 0.02306 | 0.044% | 0.044% |
| CD-Inactive | | 1,306 | 0.01% | 0.00000 | 0.000% | 0.000% |
| ADIT | | 1,318,615 | 13.73% | 0.00000 | 0.000% | 0.000% |
| FAS 109 | | (164,391) | -1.71% | 0.00000 | 0.000% | 0.000% |
| ITC | | 498 | 0.01% | 0.00000 | 0.000% | 0.000% |
| Total | $ | 9,602,073 | 100.00% | | 7.146% | 10.361% |
| | | | | Total Debt | 2.026% | 2.026% |
| | | | | Total Equity | 5.120% | 8.335% |

May 2015 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

# INDEX

## TAMPA ELECTRIC COMPANY
## ENVIRONMENTAL COST RECOVERY CLAUSE

## FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2014 THROUGH DECEMBER 2014

## FORMS 42-1A THROUGH 42-9A


| DOCUMENT NO. | TITLE | PAGE |
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| 9 | Form 42-9A | 42 |


FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 21
PARTY: TAMPA ELECTRIC COMPANY (TECO) – (DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-1

**Tampa Electric Company**

Form 42 - 1A

Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**
(in Dollars)

| Line | | Period Amount |
|---|---|---|
| 1. | End of Period Actual True-Up for the Period January 2014 to December 2014 (Form 42-2A, Lines 5 + 6 + 10) | $3,020,040 |
| 2. | Actual/Estimated True-Up Amount Approved for the Period January 2014 to December 2014 (Order No. PSC-14-0643-FOF-EI) | 6,935,676 |
| 4. | Final True-Up to be Refunded/(Recovered) in the Projection Period January 2016 to December 2016 (Lines 1 - 2) | ($3,915,636) |

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DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 1, PAGE 1 OF 1

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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) | $6,863,889 | $6,593,330 | $6,130,408 | $6,198,652 | $7,285,937 | $8,524,025 | $8,919,896 | $8,736,936 | $8,942,271 | $7,777,921 | $6,605,394 | $6,517,712 | $89,096,371 |
| 2. | True-Up Provision | (204,961) | (204,961) | (204,961) | (204,961) | (204,961) | (204,961) | (204,961) | (204,961) | (204,961) | (204,961) | (204,961) | (204,963) | (2,459,534) |
| 3. | ECRC Revenues Applicable to Period (Lines 1 + 2) | 6,658,928 | 6,388,369 | 5,925,447 | 5,993,691 | 7,080,976 | 8,319,064 | 8,714,935 | 8,531,975 | 8,737,310 | 7,572,960 | 6,400,433 | 6,312,749 | 86,636,837 |
| 4. | Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| | a. O & M Activities (Form 42-5A, Line 9) | 1,868,471 | 2,441,199 | 2,028,291 | 1,867,750 | 2,348,838 | 3,261,799 | 2,155,276 | 3,189,749 | 2,216,318 | 2,961,306 | 2,175,763 | 2,404,664 | 28,919,424 |
| | b. Capital Investment Projects (Form 42-7A, Line 9) | 4,606,744 | 4,600,567 | 4,594,325 | 4,584,666 | 4,597,287 | 4,616,763 | 4,506,859 | 4,496,859 | 4,486,268 | 4,475,641 | 4,543,863 | 4,667,075 | 54,776,917 |
| | c. Total Jurisdictional ECRC Costs | 6,475,215 | 7,041,766 | 6,622,616 | 6,452,416 | 6,946,125 | 7,878,562 | 6,662,135 | 7,686,608 | 6,702,586 | 7,436,947 | 6,719,626 | 7,071,739 | 83,696,341 |
| 5. | Over/Under Recovery (Line 3 - Line 4c) | 183,713 | (653,397) | (697,169) | (458,725) | 134,851 | 440,502 | 2,052,800 | 845,367 | 2,034,724 | 136,013 | (319,193) | (758,990) | 2,940,496 |
| 6. | Interest Provision (Form 42-3A, Line 10) | (14) | (13) | (37) | (66) | (53) | (23) | 44 | 127 | 209 | 274 | 335 | 420 | 1,203 |
| 7. | Beginning Balance True-Up & Interest Provision | (2,459,534) | (1,992,533) | (2,440,982) | (2,933,227) | (3,187,057) | (2,847,298) | (2,201,858) | 55,947 | 1,106,402 | 3,346,296 | 3,687,544 | 3,573,647 | (2,459,534) |
| | a. Deferred True-Up from January to December 2013 (Order No. PSC-14-0643-FOF-EI) | 1,957,072 | 1,957,072 | 1,957,072 | 1,957,072 | 1,957,072 | 1,957,072 | 1,957,072 | 1,957,072 | 1,957,072 | 1,957,072 | 1,957,072 | 1,957,072 | 1,957,072 |
| 8. | True-Up Collected/(Refunded) (see Line 2) | 204,961 | 204,961 | 204,961 | 204,961 | 204,961 | 204,961 | 204,961 | 204,961 | 204,961 | 204,961 | 204,961 | 204,963 | 2,459,534 |
| 9. | End of Period Total True-Up (Lines 5+6+7+7a+8) | (113,802) | (483,910) | (976,155) | (1,229,985) | (890,226) | (244,786) | 2,013,019 | 3,063,474 | 5,303,368 | 5,644,616 | 5,530,719 | 4,977,112 | 4,898,771 |
| 10. | Adjustment to Period True-Up Including Interest | 78,341 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 78,341 |
| 11. | End of Period Total True-Up (Lines 9 + 10) | ($35,461) | ($483,910) | ($976,155) | ($1,229,985) | ($890,226) | ($244,786) | $2,013,019 | $3,063,474 | $5,303,368 | $5,644,616 | $5,530,719 | $4,977,112 | $4,977,112 |



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 2, PAGE 1 OF 1

Form 42 - 3A

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

**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) | ($424,121) | ($35,461) | ($483,910) | ($976,155) | ($1,229,985) | ($890,226) | ($244,786) | $2,013,019 | $3,063,474 | $5,303,368 | $5,644,616 | $5,530,719 | |
| 2. | Ending True-Up Amount Before Interest | (35,447) | (483,897) | (976,118) | (1,229,919) | (890,173) | (244,763) | 2,012,975 | 3,063,347 | 5,303,159 | 5,644,342 | 5,530,384 | 4,976,692 | |
| 3. | Total of Beginning & Ending True-Up (Lines 1 + 2) | (459,568) | (519,358) | (1,460,028) | (2,206,074) | (2,120,158) | (1,134,989) | 1,768,189 | 5,076,366 | 8,366,633 | 10,947,710 | 11,175,000 | 10,507,411 | |
| 4. | Average True-Up Amount (Line 3 x 1/2) | (229,784) | (259,679) | (730,014) | (1,103,037) | (1,060,079) | (567,495) | 884,095 | 2,538,183 | 4,183,317 | 5,473,855 | 5,587,500 | 5,253,706 | |
| 5. | Interest Rate (First Day of Reporting Business Month) | 0.08% | 0.07% | 0.06% | 0.07% | 0.08% | 0.04% | 0.06% | 0.06% | 0.07% | 0.06% | 0.07% | 0.08% | |
| 6. | Interest Rate (First Day of Subsequent Business Month) | 0.07% | 0.06% | 0.07% | 0.08% | 0.04% | 0.06% | 0.06% | 0.07% | 0.06% | 0.07% | 0.08% | 0.10% | |
| 7. | Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 0.15% | 0.13% | 0.13% | 0.15% | 0.12% | 0.10% | 0.12% | 0.13% | 0.13% | 0.13% | 0.15% | 0.18% | |
| 8. | Average Interest Rate (Line 7 x 1/2) | 0.075% | 0.065% | 0.065% | 0.075% | 0.060% | 0.050% | 0.060% | 0.065% | 0.065% | 0.065% | 0.075% | 0.090% | |
| 9. | Monthly Average Interest Rate (Line 8 x 1/12) | 0.006% | 0.005% | 0.005% | 0.006% | 0.005% | 0.004% | 0.005% | 0.005% | 0.005% | 0.005% | 0.006% | 0.008% | |
| 10. | Interest Provision for the Month (Line 4 x Line 9) | ($14) | ($13) | ($37) | ($66) | ($53) | ($23) | $44 | $127 | $209 | $274 | $335 | $420 | $1,203 |



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 3, PAGE 1 OF 1

**Tampa Electric Company** Form 42 - 4A

Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

**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 | $5,627,948 | $5,127,113 | $500,835 | 9.8% |
| | b. Big Bend Units 1 & 2 Flue Gas Conditioning | - | - | - | 0.0% |
| | c. $SO_2$ Emissions Allowances | (125) | 11,331 | (11,456) | -101.1% |
| | d. Big Bend Units 1 & 2 FGD | 11,356,066 | 11,132,440 | 223,626 | 2.0% |
| | e. Big Bend PM Minimization and Monitoring | 789,074 | 834,530 | (45,456) | -5.4% |
| | f. Big Bend $NO_x$ Emissions Reduction | 135,594 | 93,609 | 41,985 | 44.9% |
| | g. NPDES Annual Surveillance Fees | 34,500 | 34,500 | - | 0.0% |
| | h. Gannon Thermal Discharge Study | - | - | - | 0.0% |
| | i. Polk $NO_x$ Emissions Reduction | 18,157 | 24,404 | (6,247) | -25.6% |
| | j. Bayside SCR Consumables | 135,882 | 129,943 | 5,939 | 4.6% |
| | k. Big Bend Unit 4 SOFA | 101,273 | 131,273 | (30,000) | -22.9% |
| | l. Big Bend Unit 1 Pre-SCR | 41,295 | 36,792 | 4,503 | 12.2% |
| | m. Big Bend Unit 2 Pre-SCR | 43,921 | 55,125 | (11,204) | -20.3% |
| | n. Big Bend Unit 3 Pre-SCR | 32,321 | 53,761 | (21,440) | -39.9% |
| | o. Clean Water Act Section 316(b) Phase II Study | 69 | 50,023 | (49,954) | -99.9% |
| | p. Arsenic Groundwater Standard Program | 966,516 | 942,705 | 23,811 | 2.5% |
| | q. Big Bend 1 SCR | 2,966,634 | 2,636,572 | 330,062 | 12.5% |
| | r. Big Bend 2 SCR | 2,978,002 | 2,605,955 | 372,047 | 14.3% |
| | s. Big Bend 3 SCR | 2,013,449 | 1,910,119 | 103,330 | 5.4% |
| | t. Big Bend 4 SCR | 982,735 | 851,578 | 131,157 | 15.4% |
| | u. Mercury Air Toxics Standards | 53,761 | 115,055 | (61,294) | -53.3% |
| | v. Greenhouse Gas Reduction Program | 120,710 | 110,991 | 9,719 | 8.8% |
| | w. Big Bend Gypsum Storage Facility | 521,642 | 795,000 | (273,358) | -34.4% |
| 2. | Total Investment Projects - Recoverable Costs | $28,919,424 | $27,682,819 | $1,236,605 | 4.5% |
| 3. | Recoverable Costs Allocated to Energy | $27,918,339 | $26,655,591 | $1,262,748 | 4.7% |
| 4. | Recoverable Costs Allocated to Demand | $1,001,085 | $1,027,228 | ($26,143) | -2.5% |

**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-14-0643-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 2014 to December 2014**

Form 42 - 5A

**O&M Activities**
(in Dollars)

| Line | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Description of O&M Activities | | | | | | | | | | | | | | | |
| | a. Big Bend Unit 3 Flue Gas Desulfurization Integration | $355,487 | $387,424 | $374,261 | $425,421 | $576,481 | $495,839 | $500,606 | $554,098 | 400,410.00 | $652,695 | $345,544 | $559,681 | $5,627,948 | | $5,627,948 |
| | 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 | (234) | (300) | 304 | (556) | 268 | 497 | 32 | 44 | 49 | (272) | (25) | 68 | (125) | | (125) |
| | d. Big Bend Units 1 & 2 FGD | 745,006 | 1,080,219 | 871,080 | 820,275 | 921,041 | 1,063,368 | 996,119 | 1,255,300 | 726,284 | 1,265,029 | 847,772 | 764,572 | 11,356,066 | | 11,356,066 |
| | e. Big Bend PM Minimization and Monitoring | 32,162 | 69,732 | 58,426 | 3,700 | 28,212 | 14,297 | 269,378 | 48,407 | 82,466 | 73,263 | 68,631 | 40,399 | 789,074 | | 789,074 |
| | f. Big Bend $NO_x$ Emissions Reduction | 4,399 | 2,614 | 21,212 | 0 | 5,342 | 41 | 2,740 | 20 | 82,795 | 4,947 | 11,388 | 96 | 135,594 | | 135,594 |
| | 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 $NO_x$ Reduction | 2,093 | 0 | 797 | 5,746 | 929 | 929 | 152 | 1,404 | 2,788 | 929 | 1,332 | 1,057 | 18,157 | | 18,157 |
| | j. Bayside SCR and Ammonia | 824 | 11,407 | 734 | 12,026 | 12,933 | 14,017 | 13,724 | 26,189 | 12,307 | 16,665 | 0 | 15,055 | 135,882 | | 135,882 |
| | k. Big Bend Unit 4 SOFA | 0 | 0 | 0 | 55,611 | 91,521 | (45,859) | 0 | 0 | 0 | 0 | 0 | 0 | 101,273 | | 101,273 |
| | l. Big Bend Unit 1 Pre-SCR | 13,490 | 42 | 725 | 0 | 3,885 | 650 | (650) | 0 | 0 | 0 | 575 | 22,578 | 41,295 | | 41,295 |
| | m. Big Bend Unit 2 Pre-SCR | 1,350 | 10,869 | 0 | 0 | 15,744 | 3,162 | 12,072 | 725 | 0 | 575 | (575) | 0 | 43,921 | | 43,921 |
| | n. Big Bend Unit 3 Pre-SCR | 575 | 0 | 20,547 | 4,010 | 1,591 | 39 | 0 | 14 | (173) | 5,144 | 575 | 0 | 32,321 | | 32,321 |
| | o. Clean Water Act Section 316(b) Phase II Study | 0 | 2 | 0 | 0 | 2 | 18 | 3 | 2 | 9 | 13 | 2 | 17 | 69 | 69 | |
| | p. Arsenic Groundwater Standard Program | 16 | 7,056 | 57 | 23,255 | (11,143) | 783,465 | (303,492) | 399,848 | 46,019 | 84 | 7,234 | 14,118 | 966,516 | 966,516 | |
| | q. Big Bend 1 SCR | 196,576 | 228,856 | 319,485 | 160,526 | 253,895 | 276,937 | 213,123 | 264,441 | 218,022 | 266,032 | 230,491 | 338,249 | 2,966,634 | | 2,966,634 |
| | r. Big Bend 2 SCR | 250,157 | 243,760 | 132,872 | 192,053 | 223,186 | 344,376 | 217,856 | 317,265 | 262,062 | 234,928 | 293,287 | 266,200 | 2,978,002 | | 2,978,002 |
| | s. Big Bend 3 SCR | 164,289 | 259,926 | 149,977 | 36,418 | 179,339 | 202,512 | 159,468 | 211,508 | 157,582 | 219,961 | 144,360 | 128,109 | 2,013,449 | | 2,013,449 |
| | t. Big Bend 4 SCR | 60,826 | 139,242 | 76,036 | 39,265 | 32,571 | 75,220 | 94,412 | 109,573 | 105,175 | 61,999 | 86,428 | 101,989 | 982,735 | | 982,735 |
| | u. Mercury Air Toxics Standards | 603 | 0 | 0 | 0 | 0 | 7,703 | 19,700 | 911 | 4,925 | 19,717 | 203 | 0 | 53,761 | | 53,761 |
| | v. Greenhouse Gas Reduction Program | 6,350 | 350 | 1,778 | 90,000 | 13,040 | 24,587 | (39,967) | 0 | 1,741 | 3,098 | 4,279 | 15,455 | 120,710 | | 120,710 |
| | w. Big Bend Gypsum Storage Facility | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 113,858 | 136,498 | 134,263 | 137,023 | 521,642 | | 521,642 |
| 2. | Total of O&M Activities | 1,868,471 | 2,441,199.00 | 2,028,291 | 1,867,750 | 2,348,838 | 3,261,799 | 2,155,276 | 3,189,749 | 2,216,318 | 2,961,306 | 2,175,763 | 2,404,664 | 28,919,424 | $1,001,085 | $27,918,339 |
| 3. | Recoverable Costs Allocated to Energy | 1,833,955 | 2,434,141 | 2,028,234 | 1,844,495 | 2,359,979 | 2,478,316 | 2,458,765 | 2,789,899 | 2,170,290 | 2,961,209 | 2,168,527 | 2,390,529 | 27,918,339 | | |
| 4. | Recoverable Costs Allocated to Demand | 34,516 | 7,058 | 57 | 23,255 | (11,141) | 783,483 | (303,489) | 399,850 | 46,028 | 97 | 7,236 | 14,135 | 1,001,085 | | |
| 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) | 1,833,955 | 2,434,141 | 2,028,234 | 1,844,495 | 2,359,979 | 2,478,316 | 2,458,765 | 2,789,899 | 2,170,290 | 2,961,209 | 2,168,527 | 2,390,529 | 27,918,339 | | |
| 8. | Jurisdictional Demand Recoverable Costs (B) | 34,516 | 7,058 | 57 | 23,255 | (11,141) | 783,483 | (303,489) | 399,850 | 46,028 | 97 | 7,236 | 14,135 | 1,001,085 | | |
| 9. | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $1,868,471 | $2,441,199 | $2,028,291 | $1,867,750 | $2,348,838 | $3,261,799 | $2,155,276 | $3,189,749 | $2,216,318 | $2,961,306 | $2,175,763 | $2,404,664 | $28,919,424 | | |

**Notes:**
(A) Line 3 x Line 5
(B) Line 4 x Line 6



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 5, PAGE 1 OF 1

**Tampa Electric Company** Form 42 - 6A

Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

**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 | $1,197,393 | $1,196,675 | $718 | 0.1% |
| | b. Big Bend Units 1 & 2 Flue Gas Conditioning | 334,436 | 334,436 | 0 | 0.0% |
| | c. Big Bend Unit 4 Continuous Emissions Monitors | 66,791 | 66,791 | 0 | 0.0% |
| | d. Big Bend Fuel Oil Tank # 1 Upgrade | 43,164 | 43,164 | 0 | 0.0% |
| | e. Big Bend Fuel Oil Tank # 2 Upgrade | 70,995 | 70,995 | 0 | 0.0% |
| | f. Big Bend Unit 1 Classifier Replacement | 106,361 | 106,361 | 0 | 0.0% |
| | g. Big Bend Unit 2 Classifier Replacement | 76,653 | 76,653 | 0 | 0.0% |
| | h. Big Bend Section 114 Mercury Testing Platform | 11,028 | 11,028 | 0 | 0.0% |
| | i. Big Bend Units 1 & 2 FGD | 7,574,912 | 7,605,280 | (30,368) | -0.4% |
| | j. Big Bend FGD Optimization and Utilization | 1,921,092 | 1,921,092 | 0 | 0.0% |
| | k. Big Bend $NO_x$ Emissions Reduction | 631,587 | 631,587 | 0 | 0.0% |
| | l. Big Bend PM Minimization and Monitoring | 1,737,085 | 1,733,781 | 3,304 | 0.2% |
| | m. Polk $NO_x$ Emissions Reduction | 146,881 | 146,881 | 0 | 0.0% |
| | n. Big Bend Unit 4 SOFA | 254,713 | 254,713 | 0 | 0.0% |
| | o. Big Bend Unit 1 Pre-SCR | 178,642 | 178,642 | 0 | 0.0% |
| | p. Big Bend Unit 2 Pre-SCR | 169,162 | 169,162 | 0 | 0.0% |
| | q. Big Bend Unit 3 Pre-SCR | 300,329 | 300,329 | 0 | 0.0% |
| | r. Big Bend Unit 1 SCR | 10,160,775 | 10,160,785 | (10) | 0.0% |
| | s. Big Bend Unit 2 SCR | 10,672,977 | 10,672,977 | 0 | 0.0% |
| | t. Big Bend Unit 3 SCR | 8,803,715 | 8,803,715 | 0 | 0.0% |
| | u. Big Bend Unit 4 SCR | 6,660,163 | 6,658,597 | 1,566 | 0.0% |
| | v. Big Bend FGD System Reliability | 2,646,671 | 2,646,671 | 0 | 0.0% |
| | w. Mercury Air Toxics Standards | 726,933 | 725,207 | 1,726 | 0.2% |
| | x. $S0_2$ Emissions Allowances | (3,354) | (3,356) | 2 | -0.1% |
| | y. Big Bend Gypsum Storage Facility | 287,813 | 559,680 | (271,867) | -48.6% |
| 2. | Total Investment Projects - Recoverable Costs | $54,776,917 | $55,071,846 | ($294,929) | -0.5% |
| 3. | Recoverable Costs Allocated to Energy | $54,662,758 | $54,957,687 | ($294,929) | -0.5% |
| 4. | Recoverable Costs Allocated to Demand | $114,159 | $114,159 | $0 | 0.0% |

**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-14-0643-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 2014 to December 2014**

Form 42-7A

**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 Integrat | 1 | $101,499 | $101,503 | $101,507 | $101,343 | $101,121 | $100,905 | $98,356 | $98,306 | $98,246 | $98,204 | $98,194 | $98,209 | $1,197,393 | | $1,197,393 |
| b. | Big Bend Units 1 and 2 Flue Gas Conditioning | 2 | 28,760 | 28,634 | 28,507 | 28,380 | 28,253 | 28,126 | 27,603 | 27,480 | 27,357 | 27,235 | 27,112 | 26,989 | 334,436 | | 334,436 |
| c. | Big Bend Unit 4 Continuous Emissions Monitors | 3 | 5,720 | 5,702 | 5,684 | 5,666 | 5,648 | 5,630 | 5,501 | 5,483 | 5,466 | 5,448 | 5,430 | 5,413 | 66,791 | | 66,791 |
| d. | Big Bend Fuel Oil Tank # 1 Upgrade | 4 | 3,694 | 3,684 | 3,672 | 3,661 | 3,651 | 3,639 | 3,554 | 3,543 | 3,533 | 3,522 | 3,511 | 3,500 | 43,164 | $43,164 | |
| e. | Big Bend Fuel Oil Tank # 2 Upgrade | 5 | 6,076 | 6,058 | 6,040 | 6,022 | 6,004 | 5,986 | 5,846 | 5,828 | 5,810 | 5,793 | 5,775 | 5,757 | 70,995 | 70,995 | |
| f. | Big Bend Unit 1 Classifier Replacement | 6 | 9,127 | 9,093 | 9,058 | 9,024 | 8,990 | 8,955 | 8,769 | 8,736 | 8,702 | 8,669 | 8,636 | 8,602 | 106,361 | | 106,361 |
| g. | Big Bend Unit 2 Classifier Replacement | 7 | 6,575 | 6,551 | 6,527 | 6,503 | 6,480 | 6,455 | 6,318 | 6,295 | 6,272 | 6,249 | 6,226 | 6,202 | 76,653 | | 76,653 |
| h. | Big Bend Section 114 Mercury Testing Platform | 8 | 942 | 940 | 937 | 936 | 933 | 931 | 907 | 905 | 902 | 901 | 898 | 896 | 11,028 | | 11,028 |
| i. | Big Bend Units 1 & 2 FGD | 9 | 643,235 | 643,288 | 643,048 | 641,676 | 639,985 | 638,534 | 624,320 | 622,894 | 621,365 | 619,760 | 618,206 | 618,601 | 7,574,912 | | 7,574,912 |
| j. | Big Bend FGD Optimization and Utilization | 10 | 163,983 | 163,628 | 163,271 | 162,916 | 162,560 | 162,204 | 157,949 | 157,604 | 157,260 | 156,916 | 156,573 | 156,228 | 1,921,092 | | 1,921,092 |
| k. | Big Bend $NO_x$ Emissions Reduction | 11 | 53,790 | 53,711 | 53,631 | 53,550 | 53,470 | 53,391 | 51,867 | 51,790 | 51,713 | 51,635 | 51,558 | 51,481 | 631,587 | | 631,587 |
| l. | Big Bend PM Minimization and Monitoring | 12 | 148,106 | 147,754 | 147,413 | 147,065 | 146,661 | 146,295 | 142,603 | 142,250 | 141,915 | 141,671 | 141,497 | 143,855 | 1,737,085 | | 1,737,085 |
| m. | Polk $NO_x$ Emissions Reduction | 13 | 12,563 | 12,527 | 12,493 | 12,458 | 12,424 | 12,389 | 12,089 | 12,055 | 12,022 | 11,987 | 11,954 | 11,920 | 146,881 | | 146,881 |
| n. | Big Bend Unit 4 SOFA | 14 | 21,752 | 21,702 | 21,652 | 21,602 | 21,551 | 21,501 | 20,947 | 20,898 | 20,850 | 20,801 | 20,753 | 20,704 | 254,713 | | 254,713 |
| o. | Big Bend Unit 1 Pre-SCR | 15 | 15,282 | 15,239 | 15,196 | 15,152 | 15,109 | 15,066 | 14,704 | 14,663 | 14,620 | 14,579 | 14,537 | 14,495 | 178,642 | | 178,642 |
| p. | Big Bend Unit 2 Pre-SCR | 16 | 14,463 | 14,425 | 14,386 | 14,348 | 14,309 | 14,271 | 13,919 | 13,882 | 13,846 | 13,808 | 13,771 | 13,734 | 169,162 | | 169,162 |
| q. | Big Bend Unit 3 Pre-SCR | 17 | 25,659 | 25,596 | 25,533 | 25,471 | 25,408 | 25,346 | 24,704 | 24,643 | 24,583 | 24,522 | 24,462 | 24,402 | 300,329 | | 300,329 |
| r. | Big Bend Unit 1 SCR | 18 | 861,255 | 861,016 | 860,848 | 858,564 | 861,960 | 859,538 | 838,790 | 836,458 | 834,110 | 831,761 | 829,412 | 827,063 | 10,160,775 | | 10,160,775 |
| s. | Big Bend Unit 2 SCR | 19 | 912,375 | 909,991 | 907,608 | 905,225 | 902,841 | 900,457 | 878,173 | 875,869 | 873,565 | 871,261 | 868,958 | 866,654 | 10,672,977 | | 10,672,977 |
| t. | Big Bend Unit 3 SCR | 20 | 752,517 | 750,570 | 748,624 | 746,678 | 744,732 | 742,786 | 724,337 | 722,456 | 720,576 | 718,694 | 716,813 | 714,932 | 8,803,715 | | 8,803,715 |
| u. | Big Bend Unit 4 SCR | 21 | 566,885 | 566,646 | 566,408 | 565,007 | 563,601 | 562,199 | 548,074 | 546,857 | 545,628 | 544,281 | 542,951 | 541,626 | 6,660,163 | | 6,660,163 |
| v. | Big Bend FGD System Reliability | 22 | 225,633 | 225,230 | 224,827 | 224,423 | 224,020 | 223,616 | 217,462 | 217,072 | 216,682 | 216,292 | 215,902 | 215,512 | 2,646,671 | | 2,646,671 |
| w. | Mercury Air Toxics Standards | 23 | 27,140 | 27,365 | 27,741 | 29,282 | 47,861 | 78,828 | 80,341 | 81,166 | 81,519 | 81,925 | 81,966 | 81,799 | 726,933 | | 726,933 |
| x. | $SO_2$ Emissions Allowances (B) | 24 | (287) | (286) | (286) | (286) | (285) | (285) | (274) | (274) | (274) | (273) | (272) | (272) | (3,354) | | (3,354) |
| y. | Big Bend Gypsum Storage Facility | 25 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 79,040 | 208,773 | 287,813 | | 287,813 |
| 2. | Total Investment Projects - Recoverable Costs | | 4,606,744 | 4,600,567 | 4,594,325 | 4,584,666 | 4,597,287 | 4,616,763 | 4,506,859 | 4,496,859 | 4,486,268 | 4,475,641 | 4,543,863 | 4,667,075 | 54,776,917 | $114,159 | $54,662,758 |
| 3. | Recoverable Costs Allocated to Energy | | 4,596,974 | 4,590,825 | 4,584,613 | 4,574,983 | 4,587,632 | 4,607,138 | 4,497,459 | 4,487,488 | 4,476,925 | 4,466,326 | 4,534,577 | 4,657,818 | 54,662,758 | | 54,662,758 |
| 4. | Recoverable Costs Allocated to Demand | | 9,770 | 9,742 | 9,712 | 9,683 | 9,655 | 9,625 | 9,400 | 9,371 | 9,343 | 9,315 | 9,286 | 9,257 | 114,159 | 114,159 | |
| 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) | | 4,596,974 | 4,590,825 | 4,584,613 | 4,574,983 | 4,587,632 | 4,607,138 | 4,497,459 | 4,487,488 | 4,476,925 | 4,466,326 | 4,534,577 | 4,657,818 | 54,662,758 | | |
| 8. | Jurisdictional Demand Recoverable Costs (D) | | 9,770 | 9,742 | 9,712 | 9,683 | 9,655 | 9,625 | 9,400 | 9,371 | 9,343 | 9,315 | 9,286 | 9,257 | 114,159 | | |
| 9. | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | | $4,606,744 | $4,600,567 | $4,594,325 | $4,584,666 | $4,597,287 | $4,616,763 | $4,506,859 | $4,496,859 | $4,486,268 | $4,475,641 | $4,543,863 | $4,667,075 | $54,776,917 | | |

**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. 150007-EI
ECRC 2014 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 2014 to December 2014**

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 | | $7,724 | $45,762 | $9,380 | $136 | $285 | $843 | $25,967 | $16,937 | 23,450 | $21,397 | $31,740 | $28,217 | $211,839 |
| | b. Clearings to Plant | | 6,977 | 3,338 | 8,681 | (1,577) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17,419 |
| | 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) | $13,418,356 | $13,425,333 | $13,428,671 | $13,437,352 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | |
| 3. | Less: Accumulated Depreciation | (4,076,533) | (4,104,488) | (4,132,457) | (4,160,433) | (4,188,427) | (4,216,418) | (4,244,409) | (4,272,400) | (4,300,391) | (4,328,382) | (4,356,373) | (4,384,364) | (4,412,355) | |
| 4. | CWIP - Non-Interest Bearing | 22,722 | 23,469 | 65,894 | 66,593 | 68,306 | 68,591 | 69,435 | 95,402 | 112,338 | 135,788 | 157,185 | 188,925 | 217,142 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $9,364,545 | 9,344,314 | 9,362,107 | 9,343,512 | 9,315,654 | 9,287,948 | 9,260,801 | 9,258,777 | 9,247,722 | 9,243,181 | 9,236,586 | 9,240,336 | 9,240,562 | |
| 6. | Average Net Investment | | 9,354,430 | 9,353,211 | 9,352,809 | 9,329,583 | 9,301,801 | 9,274,375 | 9,259,789 | 9,253,249 | 9,245,452 | 9,239,884 | 9,238,461 | 9,240,449 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 56,315 | 56,308 | 56,305 | 56,166 | 55,998 | 55,833 | 54,667 | 54,628 | 54,582 | 54,549 | 54,541 | 54,553 | $664,445 |
| | b. Debt Component Grossed Up For Taxes (C) | | 17,229 | 17,226 | 17,226 | 17,183 | 17,132 | 17,081 | 15,698 | 15,687 | 15,673 | 15,664 | 15,662 | 15,665 | 197,126 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 27,955 | 27,969 | 27,976 | 27,994 | 27,991 | 27,991 | 27,991 | 27,991 | 27,991 | 27,991 | 27,991 | 27,991 | 335,822 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 101,499 | 101,503 | 101,507 | 101,343 | 101,121 | 100,905 | 98,356 | 98,306 | 98,246 | 98,204 | 98,194 | 98,209 | 1,197,393 |
| | a. Recoverable Costs Allocated to Energy | | 101,499 | 101,503 | 101,507 | 101,343 | 101,121 | 100,905 | 98,356 | 98,306 | 98,246 | 98,204 | 98,194 | 98,209 | 1,197,393 |
| | b. Recoverable Costs 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) | | 101,499 | 101,503 | 101,507 | 101,343 | 101,121 | 100,905 | 98,356 | 98,306 | 98,246 | 98,204 | 98,194 | 98,209 | 1,197,393 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $101,499 | $101,503 | $101,507 | $101,343 | $101,121 | $100,905 | $98,356 | $98,306 | $98,246 | $98,204 | $98,194 | $98,209 | $1,197,393 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 1 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (3,404,510) | (3,420,651) | (3,436,792) | (3,452,933) | (3,469,074) | (3,485,215) | (3,501,356) | (3,517,497) | (3,533,638) | (3,549,779) | (3,565,920) | (3,582,061) | (3,598,202) | |
| 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) | $1,613,224 | 1,597,083 | 1,580,942 | 1,564,801 | 1,548,660 | 1,532,519 | 1,516,378 | 1,500,237 | 1,484,096 | 1,467,955 | 1,451,814 | 1,435,673 | 1,419,532 | |
| 6. | Average Net Investment | | 1,605,154 | 1,589,013 | 1,572,872 | 1,556,731 | 1,540,590 | 1,524,449 | 1,508,308 | 1,492,167 | 1,476,026 | 1,459,885 | 1,443,744 | 1,427,603 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 9,663 | 9,566 | 9,469 | 9,372 | 9,275 | 9,177 | 8,905 | 8,809 | 8,714 | 8,619 | 8,523 | 8,428 | $108,520 |
| | b. Debt Component Grossed Up For Taxes (C) | | 2,956 | 2,927 | 2,897 | 2,867 | 2,837 | 2,808 | 2,557 | 2,530 | 2,502 | 2,475 | 2,448 | 2,420 | 32,224 |
| 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) | | 28,760 | 28,634 | 28,507 | 28,380 | 28,253 | 28,126 | 27,603 | 27,480 | 27,357 | 27,235 | 27,112 | 26,989 | 334,436 |
| | a. Recoverable Costs Allocated to Energy | | 28,760 | 28,634 | 28,507 | 28,380 | 28,253 | 28,126 | 27,603 | 27,480 | 27,357 | 27,235 | 27,112 | 26,989 | 334,436 |
| | b. Recoverable Costs 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) | | 28,760 | 28,634 | 28,507 | 28,380 | 28,253 | 28,126 | 27,603 | 27,480 | 27,357 | 27,235 | 27,112 | 26,989 | 334,436 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $28,760 | $28,634 | $28,507 | $28,380 | $28,253 | $28,126 | $27,603 | $27,480 | $27,357 | $27,235 | $27,112 | $26,989 | $334,436 |

**Notes:**
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% 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



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 2 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (431,285) | (433,595) | (435,905) | (438,215) | (440,525) | (442,835) | (445,145) | (447,455) | (449,765) | (452,075) | (454,385) | (456,695) | (459,005) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $434,926 | 432,616 | 430,306 | 427,996 | 425,686 | 423,376 | 421,066 | 418,756 | 416,446 | 414,136 | 411,826 | 409,516 | 407,206 | |
| 6. | Average Net Investment | | 433,771 | 431,461 | 429,151 | 426,841 | 424,531 | 422,221 | 419,911 | 417,601 | 415,291 | 412,981 | 410,671 | 408,361 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 2,611 | 2,597 | 2,584 | 2,570 | 2,556 | 2,542 | 2,479 | 2,465 | 2,452 | 2,438 | 2,424 | 2,411 | $30,129 |
| | b. Debt Component Grossed Up For Taxes (C) | | 799 | 795 | 790 | 786 | 782 | 778 | 712 | 708 | 704 | 700 | 696 | 692 | 8,942 |
| 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) | | 5,720 | 5,702 | 5,684 | 5,666 | 5,648 | 5,630 | 5,501 | 5,483 | 5,466 | 5,448 | 5,430 | 5,413 | 66,791 |
| | a. Recoverable Costs Allocated to Energy | | 5,720 | 5,702 | 5,684 | 5,666 | 5,648 | 5,630 | 5,501 | 5,483 | 5,466 | 5,448 | 5,430 | 5,413 | 66,791 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 5,720 | 5,702 | 5,684 | 5,666 | 5,648 | 5,630 | 5,501 | 5,483 | 5,466 | 5,448 | 5,430 | 5,413 | 66,791 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $5,720 | $5,702 | $5,684 | $5,666 | $5,648 | $5,630 | $5,501 | $5,483 | $5,466 | $5,448 | $5,430 | $5,413 | $66,791 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 3 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**



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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (206,272) | (207,682) | (209,092) | (210,502) | (211,912) | (213,322) | (214,732) | (216,142) | (217,552) | (218,962) | (220,372) | (221,782) | (223,192) | |
| 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) | $291,306 | 289,896 | 288,486 | 287,076 | 285,666 | 284,256 | 282,846 | 281,436 | 280,026 | 278,616 | 277,206 | 275,796 | 274,386 | |
| 6. | Average Net Investment | | 290,601 | 289,191 | 287,781 | 286,371 | 284,961 | 283,551 | 282,141 | 280,731 | 279,321 | 277,911 | 276,501 | 275,091 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 1,749 | 1,741 | 1,732 | 1,724 | 1,716 | 1,707 | 1,666 | 1,657 | 1,649 | 1,641 | 1,632 | 1,624 | $20,238 |
| | b. Debt Component Grossed Up For Taxes (C) | | 535 | 533 | 530 | 527 | 525 | 522 | 478 | 476 | 474 | 471 | 469 | 466 | 6,006 |
| 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) | | 3,694 | 3,684 | 3,672 | 3,661 | 3,651 | 3,639 | 3,554 | 3,543 | 3,533 | 3,522 | 3,511 | 3,500 | 43,164 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 3,694 | 3,684 | 3,672 | 3,661 | 3,651 | 3,639 | 3,554 | 3,543 | 3,533 | 3,522 | 3,511 | 3,500 | 43,164 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 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) | | 3,694 | 3,684 | 3,672 | 3,661 | 3,651 | 3,639 | 3,554 | 3,543 | 3,533 | 3,522 | 3,511 | 3,500 | 43,164 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $3,694 | $3,684 | $3,672 | $3,661 | $3,651 | $3,639 | $3,554 | $3,543 | $3,533 | $3,522 | $3,511 | $3,500 | $43,164 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 4 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (339,280) | (341,599) | (343,918) | (346,237) | (348,556) | (350,875) | (353,194) | (355,513) | (357,832) | (360,151) | (362,470) | (364,789) | (367,108) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $479,121 | 476,802 | 474,483 | 472,164 | 469,845 | 467,526 | 465,207 | 462,888 | 460,569 | 458,250 | 455,931 | 453,612 | 451,293 | |
| 6. | Average Net Investment | | 477,962 | 475,643 | 473,324 | 471,005 | 468,686 | 466,367 | 464,048 | 461,729 | 459,410 | 457,091 | 454,772 | 452,453 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 2,877 | 2,863 | 2,849 | 2,836 | 2,822 | 2,808 | 2,740 | 2,726 | 2,712 | 2,699 | 2,685 | 2,671 | $33,288 |
| | b. Debt Component Grossed Up For Taxes (C) | | 880 | 876 | 872 | 867 | 863 | 859 | 787 | 783 | 779 | 775 | 771 | 767 | 9,879 |
| 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) | | 6,076 | 6,058 | 6,040 | 6,022 | 6,004 | 5,986 | 5,846 | 5,828 | 5,810 | 5,793 | 5,775 | 5,757 | 70,995 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 6,076 | 6,058 | 6,040 | 6,022 | 6,004 | 5,986 | 5,846 | 5,828 | 5,810 | 5,793 | 5,775 | 5,757 | 70,995 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 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) | | 6,076 | 6,058 | 6,040 | 6,022 | 6,004 | 5,986 | 5,846 | 5,828 | 5,810 | 5,793 | 5,775 | 5,757 | 70,995 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $6,076 | $6,058 | $6,040 | $6,022 | $6,004 | $5,986 | $5,846 | $5,828 | $5,810 | $5,793 | $5,775 | $5,757 | $70,995 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 5 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (711,224) | (715,612) | (720,000) | (724,388) | (728,776) | (733,164) | (737,552) | (741,940) | (746,328) | (750,716) | (755,104) | (759,492) | (763,880) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $605,033 | 600,645 | 596,257 | 591,869 | 587,481 | 583,093 | 578,705 | 574,317 | 569,929 | 565,541 | 561,153 | 556,765 | 552,377 | |
| 6. | Average Net Investment | | 602,839 | 598,451 | 594,063 | 589,675 | 585,287 | 580,899 | 576,511 | 572,123 | 567,735 | 563,347 | 558,959 | 554,571 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 3,629 | 3,603 | 3,576 | 3,550 | 3,524 | 3,497 | 3,404 | 3,378 | 3,352 | 3,326 | 3,300 | 3,274 | $41,413 |
| | b. Debt Component Grossed Up For Taxes (C) | | 1,110 | 1,102 | 1,094 | 1,086 | 1,078 | 1,070 | 977 | 970 | 962 | 955 | 948 | 940 | 12,292 |
| 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) | | 9,127 | 9,093 | 9,058 | 9,024 | 8,990 | 8,955 | 8,769 | 8,736 | 8,702 | 8,669 | 8,636 | 8,602 | 106,361 |
| | a. Recoverable Costs Allocated to Energy | | 9,127 | 9,093 | 9,058 | 9,024 | 8,990 | 8,955 | 8,769 | 8,736 | 8,702 | 8,669 | 8,636 | 8,602 | 106,361 |
| | b. Recoverable Costs 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) | | 9,127 | 9,093 | 9,058 | 9,024 | 8,990 | 8,955 | 8,769 | 8,736 | 8,702 | 8,669 | 8,636 | 8,602 | 106,361 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $9,127 | $9,093 | $9,058 | $9,024 | $8,990 | $8,955 | $8,769 | $8,736 | $8,702 | $8,669 | $8,636 | $8,602 | $106,361 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 6 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (533,142) | (536,178) | (539,214) | (542,250) | (545,286) | (548,322) | (551,358) | (554,394) | (557,430) | (560,466) | (563,502) | (566,538) | (569,574) | |
| 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) | $451,652 | 448,616 | 445,580 | 442,544 | 439,508 | 436,472 | 433,436 | 430,400 | 427,364 | 424,328 | 421,292 | 418,256 | 415,220 | |
| 6. | Average Net Investment | | 450,134 | 447,098 | 444,062 | 441,026 | 437,990 | 434,954 | 431,918 | 428,882 | 425,846 | 422,810 | 419,774 | 416,738 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 2,710 | 2,692 | 2,673 | 2,655 | 2,637 | 2,618 | 2,550 | 2,532 | 2,514 | 2,496 | 2,478 | 2,460 | $31,015 |
| | b. Debt Component Grossed Up For Taxes (C) | | 829 | 823 | 818 | 812 | 807 | 801 | 732 | 727 | 722 | 717 | 712 | 706 | 9,206 |
| 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) | | 6,575 | 6,551 | 6,527 | 6,503 | 6,480 | 6,455 | 6,318 | 6,295 | 6,272 | 6,249 | 6,226 | 6,202 | 76,653 |
| | a. Recoverable Costs Allocated to Energy | | 6,575 | 6,551 | 6,527 | 6,503 | 6,480 | 6,455 | 6,318 | 6,295 | 6,272 | 6,249 | 6,226 | 6,202 | 76,653 |
| | b. Recoverable Costs 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) | | 6,575 | 6,551 | 6,527 | 6,503 | 6,480 | 6,455 | 6,318 | 6,295 | 6,272 | 6,249 | 6,226 | 6,202 | 76,653 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $6,575 | $6,551 | $6,527 | $6,503 | $6,480 | $6,455 | $6,318 | $6,295 | $6,272 | $6,249 | $6,226 | $6,202 | $76,653 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 7 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (37,891) | (38,183) | (38,475) | (38,767) | (39,059) | (39,351) | (39,643) | (39,935) | (40,227) | (40,519) | (40,811) | (41,103) | (41,395) | |
| 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) | $82,846 | 82,554 | 82,262 | 81,970 | 81,678 | 81,386 | 81,094 | 80,802 | 80,510 | 80,218 | 79,926 | 79,634 | 79,342 | |
| 6. | Average Net Investment | | 82,700 | 82,408 | 82,116 | 81,824 | 81,532 | 81,240 | 80,948 | 80,656 | 80,364 | 80,072 | 79,780 | 79,488 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 498 | 496 | 494 | 493 | 491 | 489 | 478 | 476 | 474 | 473 | 471 | 469 | $5,802 |
| | b. Debt Component Grossed Up For Taxes (C) | | 152 | 152 | 151 | 151 | 150 | 150 | 137 | 137 | 136 | 136 | 135 | 135 | 1,722 |
| 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) | | 942 | 940 | 937 | 936 | 933 | 931 | 907 | 905 | 902 | 901 | 898 | 896 | 11,028 |
| | a. Recoverable Costs Allocated to Energy | | 942 | 940 | 937 | 936 | 933 | 931 | 907 | 905 | 902 | 901 | 898 | 896 | 11,028 |
| | b. Recoverable Costs 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) | | 942 | 940 | 937 | 936 | 933 | 931 | 907 | 905 | 902 | 901 | 898 | 896 | 11,028 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $942 | $940 | $937 | $936 | $933 | $931 | $907 | $905 | $902 | $901 | $898 | $896 | $11,028 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 8 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | | $485,130 | $23,341 | $51,649 | $21,888 | $46,580 | $83,080 | $63,515 | 69,278 | $36,787 | $49,324 | $50,715 | $19,893 | $1,001,180 |
| | b. Clearings to Plant | | 14,990 | 486,750 | 80,098 | $13,971 | 14,210 | 4,813 | 1,107 | 209 | 0 | 0 | 751,616 | 19,893 | 1,387,657 |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other - AFUDC (excl from CWIP) | | 38,080 | 106,333 | 112,909 | 33,281 | 81,845 | 58,571 | 45,882 | 126,757 | 103,907 | 155,703 | 69,593 | 50,531 | 983,392 |
| 2. | Plant-in-Service/Depreciation Base (A) | $91,880,808 | $91,895,798 | 92,382,548 | $92,462,646 | $92,476,617 | $92,490,827 | $92,495,640 | $92,496,747 | $92,496,956 | $92,496,956 | $92,496,956 | $93,248,572 | $93,268,465 | |
| 3. | Less: Accumulated Depreciation | (42,675,732) | (42,928,404) | (43,181,117) | (43,435,169) | (43,689,441) | (43,943,752) | (44,198,102) | (44,452,465) | (44,706,831) | (44,961,198) | (45,215,565) | (45,469,932) | (45,726,366) | |
| 4. | CWIP - Non-Interest Bearing | 356,516 | 826,656 | 363,246 | 364,759 | 372,676 | 405,046 | 483,313 | 545,721 | 614,790 | 651,577 | 700,901 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $49,561,592 | 49,794,050 | 49,564,678 | 49,392,236 | 49,159,852 | 48,952,121 | 48,780,851 | 48,590,003 | 48,404,915 | 48,187,335 | 47,982,293 | 47,778,640 | 47,542,099 | |
| 6. | Average Net Investment | | 49,677,821 | 49,679,364 | 49,478,457 | 49,276,044 | 49,055,986 | 48,866,486 | 48,685,427 | 48,497,459 | 48,296,125 | 48,084,814 | 47,880,466 | 47,660,370 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 299,069 | 299,078 | 297,869 | 296,650 | 295,325 | 294,184 | 287,423 | 286,313 | 285,124 | 283,877 | 282,670 | 281,371 | $3,488,953 |
| | b. Debt Component Grossed Up For Taxes (C) | | 91,494 | 91,497 | 91,127 | 90,754 | 90,349 | 90,000 | 82,534 | 82,215 | 81,874 | 81,516 | 81,169 | 80,796 | 1,035,325 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 252,672 | 252,713 | 254,052 | 254,272 | 254,311 | 254,350 | 254,363 | 254,366 | 254,367 | 254,367 | 254,367 | 256,434 | 3,050,634 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 643,235 | 643,288 | 643,048 | 641,676 | 639,985 | 638,534 | 624,320 | 622,894 | 621,365 | 619,760 | 618,206 | 618,601 | 7,574,912 |
| | a. Recoverable Costs Allocated to Energy | | 643,235 | 643,288 | 643,048 | 641,676 | 639,985 | 638,534 | 624,320 | 622,894 | 621,365 | 619,760 | 618,206 | 618,601 | 7,574,912 |
| | b. Recoverable Costs 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) | | 643,235 | 643,288 | 643,048 | 641,676 | 639,985 | 638,534 | 624,320 | 622,894 | 621,365 | 619,760 | 618,206 | 618,601 | 7,574,912 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $643,235 | $643,288 | $643,048 | $641,676 | $639,985 | $638,534 | $624,320 | $622,894 | $621,365 | $619,760 | $618,206 | $618,601 | $7,574,912 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rates are 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 9 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | $21,739,737 | $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 | (6,617,773) | (6,663,047) | (6,708,321) | (6,753,595) | (6,798,869) | (6,844,143) | (6,889,417) | (6,934,691) | (6,979,965) | (7,025,239) | (7,070,513) | (7,115,787) | (7,161,061) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $15,121,964 | 15,076,690 | 15,031,416 | 14,986,142 | 14,940,868 | 14,895,594 | 14,850,320 | 14,805,046 | 14,759,772 | 14,714,498 | 14,669,224 | 14,623,950 | 14,578,676 | |
| 6. | Average Net Investment | | 15,099,327 | 15,054,053 | 15,008,779 | 14,963,505 | 14,918,231 | 14,872,957 | 14,827,683 | 14,782,409 | 14,737,135 | 14,691,861 | 14,646,587 | 14,601,313 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 90,900 | 90,628 | 90,355 | 90,083 | 89,810 | 89,538 | 87,538 | 87,270 | 87,003 | 86,736 | 86,469 | 86,201 | $1,062,531 |
| | b. Debt Component Grossed Up For Taxes (C) | | 27,809 | 27,726 | 27,642 | 27,559 | 27,476 | 27,392 | 25,137 | 25,060 | 24,983 | 24,906 | 24,830 | 24,753 | 315,273 |
| 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) | | 163,983 | 163,628 | 163,271 | 162,916 | 162,560 | 162,204 | 157,949 | 157,604 | 157,260 | 156,916 | 156,573 | 156,228 | 1,921,092 |
| | a. Recoverable Costs Allocated to Energy | | 163,983 | 163,628 | 163,271 | 162,916 | 162,560 | 162,204 | 157,949 | 157,604 | 157,260 | 156,916 | 156,573 | 156,228 | 1,921,092 |
| | b. Recoverable Costs 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) | | 163,983 | 163,628 | 163,271 | 162,916 | 162,560 | 162,204 | 157,949 | 157,604 | 157,260 | 156,916 | 156,573 | 156,228 | 1,921,092 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $163,983 | $163,628 | $163,271 | $162,916 | $162,560 | $162,204 | $157,949 | $157,604 | $157,260 | $156,916 | $156,573 | $156,228 | $1,921,092 |

**Notes:**

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,699,919)and 311.45 ($39,818)
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% 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. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 10 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | 2,360,811 | 2,350,627 | 2,340,443 | 2,330,259 | 2,320,075 | 2,309,891 | 2,299,707 | 2,289,523 | 2,279,339 | 2,269,155 | 2,258,971 | 2,248,787 | 2,238,603 | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $5,551,663 | 5,541,479 | 5,531,295 | 5,521,111 | 5,510,927 | 5,500,743 | 5,490,559 | 5,480,375 | 5,470,191 | 5,460,007 | 5,449,823 | 5,439,639 | 5,429,455 | |
| 6. | Average Net Investment | | 5,546,571 | 5,536,387 | 5,526,203 | 5,516,019 | 5,505,835 | 5,495,651 | 5,485,467 | 5,475,283 | 5,465,099 | 5,454,915 | 5,444,731 | 5,434,547 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 33,391 | 33,330 | 33,269 | 33,207 | 33,146 | 33,085 | 32,384 | 32,324 | 32,264 | 32,204 | 32,144 | 32,084 | $392,832 |
| | b. Debt Component Grossed Up For Taxes (C) | | 10,215 | 10,197 | 10,178 | 10,159 | 10,140 | 10,122 | 9,299 | 9,282 | 9,265 | 9,247 | 9,230 | 9,213 | 116,547 |
| 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) | | 53,790 | 53,711 | 53,631 | 53,550 | 53,470 | 53,391 | 51,867 | 51,790 | 51,713 | 51,635 | 51,558 | 51,481 | 631,587 |
| | a. Recoverable Costs Allocated to Energy | | 53,790 | 53,711 | 53,631 | 53,550 | 53,470 | 53,391 | 51,867 | 51,790 | 51,713 | 51,635 | 51,558 | 51,481 | 631,587 |
| | b. Recoverable Costs 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) | | 53,790 | 53,711 | 53,631 | 53,550 | 53,470 | 53,391 | 51,867 | 51,790 | 51,713 | 51,635 | 51,558 | 51,481 | 631,587 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $53,790 | $53,711 | $53,631 | $53,550 | $53,470 | $53,391 | $51,867 | $51,790 | $51,713 | $51,635 | $51,558 | $51,481 | $631,587 |

**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 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% 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. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 11 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | | $1,990 | $1,162 | $5,579 | ($5,579) | $0 | $0 | $81 | $0 | $4,874 | $23,776 | $23,213 | $690,325 | $745,420 |
| | b. Clearings to Plant | | 0 | (42) | 5,579 | (5,579) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (42) |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | $15,439,589 | $15,439,589 | $15,439,547 | $15,445,126 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | |
| 3. | Less: Accumulated Depreciation | (2,492,883) | (2,539,362) | (2,585,841) | (2,632,319) | (2,678,814) | (2,725,292) | (2,771,770) | (2,818,248) | (2,864,726) | (2,911,204) | (2,957,682) | (3,004,160) | (3,050,638) | |
| 4. | CWIP - Non-Interest Bearing | 2,069 | 4,059 | 5,263 | 5,263 | 5,263 | 5,263 | 5,263 | 5,343 | 5,343 | 10,217 | 33,993 | 57,206 | 747,531 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $12,948,775 | 12,904,286 | 12,858,969 | 12,818,070 | 12,765,996 | 12,719,518 | 12,673,040 | 12,626,642 | 12,580,164 | 12,538,560 | 12,515,859 | 12,492,593 | 13,136,441 | |
| 6. | Average Net Investment | | 12,926,531 | 12,881,628 | 12,838,519 | 12,792,033 | 12,742,757 | 12,696,279 | 12,649,841 | 12,603,403 | 12,559,362 | 12,527,209 | 12,504,226 | 12,814,517 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 77,820 | 77,550 | 77,290 | 77,010 | 76,714 | 76,434 | 74,680 | 74,406 | 74,146 | 73,956 | 73,821 | 75,653 | $909,480 |
| | b. Debt Component Grossed Up For Taxes (C) | | 23,807 | 23,725 | 23,645 | 23,560 | 23,469 | 23,383 | 21,445 | 21,366 | 21,291 | 21,237 | 21,198 | 21,724 | 269,850 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 46,479 | 46,479 | 46,478 | 46,495 | 46,478 | 46,478 | 46,478 | 46,478 | 46,478 | 46,478 | 46,478 | 46,478 | 557,755 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 148,106 | 147,754 | 147,413 | 147,065 | 146,661 | 146,295 | 142,603 | 142,250 | 141,915 | 141,671 | 141,497 | 143,855 | 1,737,085 |
| | a. Recoverable Costs Allocated to Energy | | 148,106 | 147,754 | 147,413 | 147,065 | 146,661 | 146,295 | 142,603 | 142,250 | 141,915 | 141,671 | 141,497 | 143,855 | 1,737,085 |
| | b. Recoverable Costs 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) | | 148,106 | 147,754 | 147,413 | 147,065 | 146,661 | 146,295 | 142,603 | 142,250 | 141,915 | 141,671 | 141,497 | 143,855 | 1,737,085 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $148,106 | $147,754 | $147,413 | $147,065 | $146,661 | $146,295 | $142,603 | $142,250 | $141,915 | $141,671 | $141,497 | $143,855 | $1,737,085 |

**Notes:**

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,513,263), 312.42 ($5,153,072), 312.43 ($7,875,602), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($528,554)
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rates are 4.0%, 3.7%, 3.5%, 3.5%, 3.2%, and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 12 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (524,058) | (528,482) | (532,906) | (537,330) | (541,754) | (546,178) | (550,602) | (555,026) | (559,450) | (563,874) | (568,298) | (572,722) | (577,146) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,037,415 | 1,032,991 | 1,028,567 | 1,024,143 | 1,019,719 | 1,015,295 | 1,010,871 | 1,006,447 | 1,002,023 | 997,599 | 993,175 | 988,751 | 984,327 | |
| 6. | Average Net Investment | | 1,035,203 | 1,030,779 | 1,026,355 | 1,021,931 | 1,017,507 | 1,013,083 | 1,008,659 | 1,004,235 | 999,811 | 995,387 | 990,963 | 986,539 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 6,232 | 6,205 | 6,179 | 6,152 | 6,126 | 6,099 | 5,955 | 5,929 | 5,903 | 5,876 | 5,850 | 5,824 | $72,330 |
| | b. Debt Component Grossed Up For Taxes (C) | | 1,907 | 1,898 | 1,890 | 1,882 | 1,874 | 1,866 | 1,710 | 1,702 | 1,695 | 1,687 | 1,680 | 1,672 | 21,463 |
| 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) | | 12,563 | 12,527 | 12,493 | 12,458 | 12,424 | 12,389 | 12,089 | 12,055 | 12,022 | 11,987 | 11,954 | 11,920 | 146,881 |
| | a. Recoverable Costs Allocated to Energy | | 12,563 | 12,527 | 12,493 | 12,458 | 12,424 | 12,389 | 12,089 | 12,055 | 12,022 | 11,987 | 11,954 | 11,920 | 146,881 |
| | b. Recoverable Costs 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) | | 12,563 | 12,527 | 12,493 | 12,458 | 12,424 | 12,389 | 12,089 | 12,055 | 12,022 | 11,987 | 11,954 | 11,920 | 146,881 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $12,563 | $12,527 | $12,493 | $12,458 | $12,424 | $12,389 | $12,089 | $12,055 | $12,022 | $11,987 | $11,954 | $11,920 | $146,881 |

**Notes:**
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (602,378) | (608,775) | (615,172) | (621,569) | (627,966) | (634,363) | (640,760) | (647,157) | (653,554) | (659,951) | (666,348) | (672,745) | (679,142) | |
| 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) | $1,956,352 | 1,949,955 | 1,943,558 | 1,937,161 | 1,930,764 | 1,924,367 | 1,917,970 | 1,911,573 | 1,905,176 | 1,898,779 | 1,892,382 | 1,885,985 | 1,879,588 | |
| 6. | Average Net Investment | | 1,953,154 | 1,946,757 | 1,940,360 | 1,933,963 | 1,927,566 | 1,921,169 | 1,914,772 | 1,908,375 | 1,901,978 | 1,895,581 | 1,889,184 | 1,882,787 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 11,758 | 11,720 | 11,681 | 11,643 | 11,604 | 11,566 | 11,304 | 11,266 | 11,229 | 11,191 | 11,153 | 11,115 | $137,230 |
| | b. Debt Component Grossed Up For Taxes (C) | | 3,597 | 3,585 | 3,574 | 3,562 | 3,550 | 3,538 | 3,246 | 3,235 | 3,224 | 3,213 | 3,203 | 3,192 | 40,719 |
| 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) | | 21,752 | 21,702 | 21,652 | 21,602 | 21,551 | 21,501 | 20,947 | 20,898 | 20,850 | 20,801 | 20,753 | 20,704 | 254,713 |
| | a. Recoverable Costs Allocated to Energy | | 21,752 | 21,702 | 21,652 | 21,602 | 21,551 | 21,501 | 20,947 | 20,898 | 20,850 | 20,801 | 20,753 | 20,704 | 254,713 |
| | b. Recoverable Costs 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) | | 21,752 | 21,702 | 21,652 | 21,602 | 21,551 | 21,501 | 20,947 | 20,898 | 20,850 | 20,801 | 20,753 | 20,704 | 254,713 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $21,752 | $21,702 | $21,652 | $21,602 | $21,551 | $21,501 | $20,947 | $20,898 | $20,850 | $20,801 | $20,753 | $20,704 | $254,713 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (401,773) | (407,270) | (412,767) | (418,264) | (423,761) | (429,258) | (434,755) | (440,252) | (445,749) | (451,246) | (456,743) | (462,240) | (467,737) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,247,348 | 1,241,851 | 1,236,354 | 1,230,857 | 1,225,360 | 1,219,863 | 1,214,366 | 1,208,869 | 1,203,372 | 1,197,875 | 1,192,378 | 1,186,881 | 1,181,384 | |
| 6. | Average Net Investment | | 1,244,600 | 1,239,103 | 1,233,606 | 1,228,109 | 1,222,612 | 1,217,115 | 1,211,618 | 1,206,121 | 1,200,624 | 1,195,127 | 1,189,630 | 1,184,133 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 7,493 | 7,460 | 7,427 | 7,393 | 7,360 | 7,327 | 7,153 | 7,121 | 7,088 | 7,056 | 7,023 | 6,991 | $86,892 |
| | b. Debt Component Grossed Up For Taxes (C) | | 2,292 | 2,282 | 2,272 | 2,262 | 2,252 | 2,242 | 2,054 | 2,045 | 2,035 | 2,026 | 2,017 | 2,007 | 25,786 |
| 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) | | 15,282 | 15,239 | 15,196 | 15,152 | 15,109 | 15,066 | 14,704 | 14,663 | 14,620 | 14,579 | 14,537 | 14,495 | 178,642 |
| | a. Recoverable Costs Allocated to Energy | | 15,282 | 15,239 | 15,196 | 15,152 | 15,109 | 15,066 | 14,704 | 14,663 | 14,620 | 14,579 | 14,537 | 14,495 | 178,642 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 15,282 | 15,239 | 15,196 | 15,152 | 15,109 | 15,066 | 14,704 | 14,663 | 14,620 | 14,579 | 14,537 | 14,495 | 178,642 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $15,282 | $15,239 | $15,196 | $15,152 | $15,109 | $15,066 | $14,704 | $14,663 | $14,620 | $14,579 | $14,537 | $14,495 | $178,642 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (360,224) | (365,101) | (369,978) | (374,855) | (379,732) | (384,609) | (389,486) | (394,363) | (399,240) | (404,117) | (408,994) | (413,871) | (418,748) | |
| 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) | $1,221,663 | 1,216,786 | 1,211,909 | 1,207,032 | 1,202,155 | 1,197,278 | 1,192,401 | 1,187,524 | 1,182,647 | 1,177,770 | 1,172,893 | 1,168,016 | 1,163,139 | |
| 6. | Average Net Investment | | 1,219,225 | 1,214,348 | 1,209,471 | 1,204,594 | 1,199,717 | 1,194,840 | 1,189,963 | 1,185,086 | 1,180,209 | 1,175,332 | 1,170,455 | 1,165,578 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 7,340 | 7,311 | 7,281 | 7,252 | 7,222 | 7,193 | 7,025 | 6,996 | 6,968 | 6,939 | 6,910 | 6,881 | $85,318 |
| | b. Debt Component Grossed Up For Taxes (C) | | 2,246 | 2,237 | 2,228 | 2,219 | 2,210 | 2,201 | 2,017 | 2,009 | 2,001 | 1,992 | 1,984 | 1,976 | 25,320 |
| 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) | | 14,463 | 14,425 | 14,386 | 14,348 | 14,309 | 14,271 | 13,919 | 13,882 | 13,846 | 13,808 | 13,771 | 13,734 | 169,162 |
| | a. Recoverable Costs Allocated to Energy | | 14,463 | 14,425 | 14,386 | 14,348 | 14,309 | 14,271 | 13,919 | 13,882 | 13,846 | 13,808 | 13,771 | 13,734 | 169,162 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 14,463 | 14,425 | 14,386 | 14,348 | 14,309 | 14,271 | 13,919 | 13,882 | 13,846 | 13,808 | 13,771 | 13,734 | 169,162 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $14,463 | $14,425 | $14,386 | $14,348 | $14,309 | $14,271 | $13,919 | $13,882 | $13,846 | $13,808 | $13,771 | $13,734 | $169,162 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 16 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (450,458) | (458,411) | (466,364) | (474,317) | (482,270) | (490,223) | (498,176) | (506,129) | (514,082) | (522,035) | (529,988) | (537,941) | (545,894) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $2,256,049 | 2,248,096 | 2,240,143 | 2,232,190 | 2,224,237 | 2,216,284 | 2,208,331 | 2,200,378 | 2,192,425 | 2,184,472 | 2,176,519 | 2,168,566 | 2,160,613 | |
| 6. | Average Net Investment | | 2,252,073 | 2,244,120 | 2,236,167 | 2,228,214 | 2,220,261 | 2,212,308 | 2,204,355 | 2,196,402 | 2,188,449 | 2,180,496 | 2,172,543 | 2,164,590 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 13,558 | 13,510 | 13,462 | 13,414 | 13,366 | 13,318 | 13,014 | 12,967 | 12,920 | 12,873 | 12,826 | 12,779 | $158,007 |
| | b. Debt Component Grossed Up For Taxes (C) | | 4,148 | 4,133 | 4,118 | 4,104 | 4,089 | 4,075 | 3,737 | 3,723 | 3,710 | 3,696 | 3,683 | 3,670 | 46,886 |
| 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) | | 25,659 | 25,596 | 25,533 | 25,471 | 25,408 | 25,346 | 24,704 | 24,643 | 24,583 | 24,522 | 24,462 | 24,402 | 300,329 |
| | a. Recoverable Costs Allocated to Energy | | 25,659 | 25,596 | 25,533 | 25,471 | 25,408 | 25,346 | 24,704 | 24,643 | 24,583 | 24,522 | 24,462 | 24,402 | 300,329 |
| | b. Recoverable Costs 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) | | 25,659 | 25,596 | 25,533 | 25,471 | 25,408 | 25,346 | 24,704 | 24,643 | 24,583 | 24,522 | 24,462 | 24,402 | 300,329 |
| 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) | | $25,659 | $25,596 | $25,533 | $25,471 | $25,408 | $25,346 | $24,704 | $24,643 | $24,583 | $24,522 | $24,462 | $24,402 | $300,329 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 3.5% and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 17 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | | $5,097 | $541,139 | $22,700 | $2,772 | $838 | $706 | $2,056 | $324 | $0 | $0 | $0 | $0 | $575,633 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 1,615,863 | 838 | 706 | 2,056 | 324 | 0 | 0 | 0 | 0 | 1,619,788 |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | $84,099,314 | $84,099,314 | $84,099,314 | $84,099,314 | $85,715,177 | $85,716,015 | $85,716,721 | $85,718,778 | $85,719,102 | $85,719,102 | $85,719,102 | $85,719,102 | $85,719,102 | |
| 3. | Less: Accumulated Depreciation | (14,032,917) | (14,336,279) | (14,639,641) | (14,943,003) | (15,246,365) | (15,555,517) | (15,864,672) | (16,173,829) | (16,482,994) | (16,792,160) | (17,101,326) | (17,410,492) | (17,719,658) | |
| 4. | CWIP - Non-Interest Bearing | 1,044,155 | 1,049,252 | 1,590,391 | 1,613,091 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $71,110,551 | 70,812,286 | 71,050,064 | 70,769,402 | 70,468,812 | 70,160,498 | 69,852,049 | 69,544,948 | 69,236,107 | 68,926,941 | 68,617,775 | 68,308,609 | 67,999,443 | |
| 6. | Average Net Investment | | 70,961,419 | 70,931,175 | 70,909,733 | 70,619,107 | 70,314,655 | 70,006,273 | 69,698,499 | 69,390,528 | 69,081,524 | 68,772,358 | 68,463,192 | 68,154,026 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 427,200 | 427,017 | 426,888 | 425,139 | 423,306 | 421,449 | 411,477 | 409,659 | 407,834 | 406,009 | 404,184 | 402,359 | $4,992,521 |
| | b. Debt Component Grossed Up For Taxes (C) | | 130,693 | 130,637 | 130,598 | 130,063 | 129,502 | 128,934 | 118,156 | 117,634 | 117,110 | 116,586 | 116,062 | 115,538 | 1,481,513 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 303,362 | 303,362 | 303,362 | 303,362 | 309,152 | 309,155 | 309,157 | 309,165 | 309,166 | 309,166 | 309,166 | 309,166 | 3,686,741 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 861,255 | 861,016 | 860,848 | 858,564 | 861,960 | 859,538 | 838,790 | 836,458 | 834,110 | 831,761 | 829,412 | 827,063 | 10,160,775 |
| | a. Recoverable Costs Allocated to Energy | | 861,255 | 861,016 | 860,848 | 858,564 | 861,960 | 859,538 | 838,790 | 836,458 | 834,110 | 831,761 | 829,412 | 827,063 | 10,160,775 |
| | b. Recoverable Costs 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) | | 861,255 | 861,016 | 860,848 | 858,564 | 861,960 | 859,538 | 838,790 | 836,458 | 834,110 | 831,761 | 829,412 | 827,063 | 10,160,775 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $861,255 | $861,016 | $860,848 | $858,564 | $861,960 | $859,538 | $838,790 | $836,458 | $834,110 | $831,761 | $829,412 | $827,063 | $10,160,775 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 311.51 ($22,278,982), 312.51 ($48,529,692), 315.51 ($14,063,245), and 316.51 ($847,203).
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 4.1%, 4.3%, 4.8% and 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 18 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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) | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | |
| 3. | Less: Accumulated Depreciation | (16,136,444) | (16,439,614) | (16,742,784) | (17,045,954) | (17,349,124) | (17,652,294) | (17,955,464) | (18,258,634) | (18,561,804) | (18,864,974) | (19,168,144) | (19,471,314) | (19,774,484) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $77,639,653 | 77,336,483 | 77,033,313 | 76,730,143 | 76,426,973 | 76,123,803 | 75,820,633 | 75,517,463 | 75,214,293 | 74,911,123 | 74,607,953 | 74,304,783 | 74,001,613 | |
| 6. | Average Net Investment | | 77,488,068 | 77,184,898 | 76,881,728 | 76,578,558 | 76,275,388 | 75,972,218 | 75,669,048 | 75,365,878 | 75,062,708 | 74,759,538 | 74,456,368 | 74,153,198 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 466,491 | 464,666 | 462,841 | 461,016 | 459,191 | 457,365 | 446,725 | 444,935 | 443,145 | 441,355 | 439,566 | 437,776 | $5,425,072 |
| | b. Debt Component Grossed Up For Taxes (C) | | 142,714 | 142,155 | 141,597 | 141,039 | 140,480 | 139,922 | 128,278 | 127,764 | 127,250 | 126,736 | 126,222 | 125,708 | 1,609,865 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 303,170 | 303,170 | 303,170 | 303,170 | 303,170 | 303,170 | 303,170 | 303,170 | 303,170 | 303,170 | 303,170 | 303,170 | 3,638,040 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 912,375 | 909,991 | 907,608 | 905,225 | 902,841 | 900,457 | 878,173 | 875,869 | 873,565 | 871,261 | 868,958 | 866,654 | 10,672,977 |
| | a. Recoverable Costs Allocated to Energy | | 912,375 | 909,991 | 907,608 | 905,225 | 902,841 | 900,457 | 878,173 | 875,869 | 873,565 | 871,261 | 868,958 | 866,654 | 10,672,977 |
| | b. Recoverable Costs 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) | | 912,375 | 909,991 | 907,608 | 905,225 | 902,841 | 900,457 | 878,173 | 875,869 | 873,565 | 871,261 | 868,958 | 866,654 | 10,672,977 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $912,375 | $909,991 | $907,608 | $905,225 | $902,841 | $900,457 | $878,173 | $875,869 | $873,565 | $871,261 | $868,958 | $866,654 | $10,672,977 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52($51,694,185), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% 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. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 19 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | |
| 3. | Less: Accumulated Depreciation | (16,015,549) | (16,263,090) | (16,510,631) | (16,758,172) | (17,005,713) | (17,253,254) | (17,500,795) | (17,748,336) | (17,995,877) | (18,243,418) | (18,490,959) | (18,738,500) | (18,986,041) | |
| 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) | $64,354,338 | 64,106,797 | 63,859,256 | 63,611,715 | 63,364,174 | 63,116,633 | 62,869,092 | 62,621,551 | 62,374,010 | 62,126,469 | 61,878,928 | 61,631,387 | 61,383,846 | |
| 6. | Average Net Investment | | 64,230,567 | 63,983,026 | 63,735,485 | 63,487,944 | 63,240,403 | 62,992,862 | 62,745,321 | 62,497,780 | 62,250,239 | 62,002,698 | 61,755,157 | 61,507,616 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 386,679 | 385,188 | 383,698 | 382,208 | 380,718 | 379,228 | 370,427 | 368,966 | 367,505 | 366,043 | 364,582 | 363,120 | $4,498,362 |
| | b. Debt Component Grossed Up For Taxes (C) | | 118,297 | 117,841 | 117,385 | 116,929 | 116,473 | 116,017 | 106,369 | 105,949 | 105,530 | 105,110 | 104,690 | 104,271 | 1,334,861 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 247,541 | 247,541 | 247,541 | 247,541 | 247,541 | 247,541 | 247,541 | 247,541 | 247,541 | 247,541 | 247,541 | 247,541 | 2,970,492 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 752,517 | 750,570 | 748,624 | 746,678 | 744,732 | 742,786 | 724,337 | 722,456 | 720,576 | 718,694 | 716,813 | 714,932 | 8,803,715 |
| | a. Recoverable Costs Allocated to Energy | | 752,517 | 750,570 | 748,624 | 746,678 | 744,732 | 742,786 | 724,337 | 722,456 | 720,576 | 718,694 | 716,813 | 714,932 | 8,803,715 |
| | b. Recoverable Costs 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) | | 752,517 | 750,570 | 748,624 | 746,678 | 744,732 | 742,786 | 724,337 | 722,456 | 720,576 | 718,694 | 716,813 | 714,932 | 8,803,715 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $752,517 | $750,570 | $748,624 | $746,678 | $744,732 | $742,786 | $724,337 | $722,456 | $720,576 | $718,694 | $716,813 | $714,932 | $8,803,715 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 311.53 ($21,689,422), 312.53 ($44,164,828), 315.53 ($13,690,954), and 316.53 ($824,683).
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rates are 3.1%, 3.9%, 4.0%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | | $1,028 | $298,059 | $1,558 | $1,855 | $285 | $3,195 | $4,583 | $34,702 | $1,952 | $3,432 | $6,669 | $4,263 | $361,579 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | |
| 3. | Less: Accumulated Depreciation | (13,706,519) | (13,886,487) | (14,066,455) | (14,246,423) | (14,426,391) | (14,606,359) | (14,786,327) | (14,966,295) | (15,146,263) | (15,326,231) | (15,506,199) | (15,686,167) | (15,866,135) | |
| 4. | CWIP - Non-Interest Bearing | 157,012 | 158,040 | 456,099 | 457,657 | 459,513 | 459,797 | 462,992 | 467,574 | 502,276 | 504,228 | 507,660 | 514,328 | 518,591 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $49,303,526 | 49,124,586 | 49,242,677 | 49,064,268 | 48,886,155 | 48,706,472 | 48,529,698 | 48,354,313 | 48,209,046 | 48,031,030 | 47,854,494 | 47,681,195 | 47,505,489 | |
| 6. | Average Net Investment | | 49,214,056 | 49,183,632 | 49,153,473 | 48,975,211 | 48,796,313 | 48,618,085 | 48,442,005 | 48,281,679 | 48,120,038 | 47,942,762 | 47,767,844 | 47,593,342 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 296,277 | 296,094 | 295,912 | 294,839 | 293,762 | 292,689 | 285,985 | 285,039 | 284,085 | 283,038 | 282,005 | 280,975 | $3,470,700 |
| | b. Debt Component Grossed Up For Taxes (C) | | 90,640 | 90,584 | 90,528 | 90,200 | 89,871 | 89,542 | 82,121 | 81,850 | 81,575 | 81,275 | 80,978 | 80,683 | 1,029,847 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 179,968 | 179,968 | 179,968 | 179,968 | 179,968 | 179,968 | 179,968 | 179,968 | 179,968 | 179,968 | 179,968 | 179,968 | 2,159,616 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 566,885 | 566,646 | 566,408 | 565,007 | 563,601 | 562,199 | 548,074 | 546,857 | 545,628 | 544,281 | 542,951 | 541,626 | 6,660,163 |
| | a. Recoverable Costs Allocated to Energy | | 566,885 | 566,646 | 566,408 | 565,007 | 563,601 | 562,199 | 548,074 | 546,857 | 545,628 | 544,281 | 542,951 | 541,626 | 6,660,163 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 566,885 | 566,646 | 566,408 | 565,007 | 563,601 | 562,199 | 548,074 | 546,857 | 545,628 | 544,281 | 542,951 | 541,626 | 6,660,163 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $566,885 | $566,646 | $566,408 | $565,007 | $563,601 | $562,199 | $548,074 | $546,857 | $545,628 | $544,281 | $542,951 | $541,626 | $6,660,163 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($34,665,822), 315.54 ($10,642,027), and 316.54 ($687,934).
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 2.4%, 3.8%. 3.9%, and 3.3%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 21 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | (2,137,830) | (2,189,139) | (2,240,448) | (2,291,757) | (2,343,066) | (2,394,375) | (2,445,684) | (2,496,993) | (2,548,302) | (2,599,611) | (2,650,920) | (2,702,229) | (2,753,538) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $22,198,877 | 22,147,568 | 22,096,259 | 22,044,950 | 21,993,641 | 21,942,332 | 21,891,023 | 21,839,714 | 21,788,405 | 21,737,096 | 21,685,787 | 21,634,478 | 21,583,169 | |
| 6. | Average Net Investment | | 22,173,223 | 22,121,914 | 22,070,605 | 22,019,296 | 21,967,987 | 21,916,678 | 21,865,369 | 21,814,060 | 21,762,751 | 21,711,442 | 21,660,133 | 21,608,824 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 133,486 | 133,178 | 132,869 | 132,560 | 132,251 | 131,942 | 129,086 | 128,783 | 128,480 | 128,177 | 127,874 | 127,571 | $1,566,257 |
| | b. Debt Component Grossed Up For Taxes (C) | | 40,838 | 40,743 | 40,649 | 40,554 | 40,460 | 40,365 | 37,067 | 36,980 | 36,893 | 36,806 | 36,719 | 36,632 | 464,706 |
| 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) | | 225,633 | 225,230 | 224,827 | 224,423 | 224,020 | 223,616 | 217,462 | 217,072 | 216,682 | 216,292 | 215,902 | 215,512 | 2,646,671 |
| | a. Recoverable Costs Allocated to Energy | | 225,633 | 225,230 | 224,827 | 224,423 | 224,020 | 223,616 | 217,462 | 217,072 | 216,682 | 216,292 | 215,902 | 215,512 | 2,646,671 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 225,633 | 225,230 | 224,827 | 224,423 | 224,020 | 223,616 | 217,462 | 217,072 | 216,682 | 216,292 | 215,902 | 215,512 | 2,646,671 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $225,633 | $225,230 | $224,827 | $224,423 | $224,020 | $223,616 | $217,462 | $217,072 | $216,682 | $216,292 | $215,902 | $215,512 | $2,646,671 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($22,880,498)
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 3.0% and 2.5%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 22 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

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 | | $16,191 | $45,414 | $62,397 | $14,688 | $376,187 | $414,919 | $133,228 | $38,537 | $73,230 | $25,352 | $10,544 | ($19,271) | $1,191,415 |
| | b. Clearings to Plant | | 13,216 | 0 | 469,335 | 61,665 | 4,686,355 | 631,681 | 138,572 | 33,893 | 74,572 | $24,121 | 8,753 | (21,170) | 6,120,992 |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other - AFUDC (excl from CWIP) | | 289,648 | 1,054,700 | 236,093 | 500,699 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,081,140 |
| 2. | Plant-in-Service/Depreciation Base (A) | $2,084,324 | $2,097,540 | $2,097,540 | $2,566,875 | $2,628,539 | $7,314,894 | $7,946,575 | $8,085,147 | $8,119,040 | $8,193,612 | $8,217,732 | $8,226,485 | $8,205,315 | |
| 3. | Less: Accumulated Depreciation | (199,403) | (205,516) | (211,661) | (217,806) | (225,242) | (232,810) | (251,368) | (271,519) | (291,997) | (312,559) | (333,310) | (354,123) | (374,961) | |
| 4. | CWIP - Non-Interest Bearing | 784,489 | 787,463 | 832,877 | 425,939 | 378,962 | 385,797 | 169,035 | 163,691 | 168,335 | 166,992 | 168,224 | 170,015 | 171,914 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $2,669,410 | 2,679,487 | 2,718,756 | 2,775,008 | 2,782,259 | 7,467,880 | 7,864,242 | 7,977,319 | 7,995,378 | 8,048,045 | 8,052,647 | 8,042,377 | 8,002,268 | |
| 6. | Average Net Investment | | 2,674,448 | 2,699,122 | 2,746,882 | 2,778,634 | 5,125,070 | 7,666,061 | 7,920,780 | 7,986,348 | 8,021,712 | 8,050,346 | 8,047,512 | 8,022,323 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 16,101 | 16,249 | 16,537 | 16,728 | 30,854 | 46,151 | 46,762 | 47,149 | 47,358 | 47,527 | 47,510 | 47,361 | $426,287 |
| | b. Debt Component Grossed Up For Taxes (C) | | 4,926 | 4,971 | 5,059 | 5,118 | 9,439 | 14,119 | 13,428 | 13,539 | 13,599 | 13,647 | 13,643 | 13,600 | 125,088 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 6,113 | 6,145 | 6,145 | 7,436 | 7,568 | 18,558 | 20,151 | 20,478 | 20,562 | 20,751 | 20,813 | 20,838 | $175,558 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 27,140 | 27,365 | 27,741 | 29,282 | 47,861 | 78,828 | 80,341 | 81,166 | 81,519 | 81,925 | 81,966 | 81,799 | 726,933 |
| | a. Recoverable Costs Allocated to Energy | | 27,140 | 27,365 | 27,741 | 29,282 | 47,861 | 78,828 | 80,341 | 81,166 | 81,519 | 81,925 | 81,966 | 81,799 | 726,933 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 27,140 | 27,365 | 27,741 | 29,282 | 47,861 | 78,828 | 80,341 | 81,166 | 81,519 | 81,925 | 81,966 | 81,799 | 726,933 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $27,140 | $27,365 | $27,741 | $29,282 | $47,861 | $78,828 | $80,341 | $81,166 | $81,519 | $81,925 | $81,966 | $81,799 | $726,933 |

**Notes:**

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.44, ($3,300,490), 341.80 ($26,150), 315.40 ($1,226,949),315.41 ($135,195), 315.42 ($135,195), 312.45 ($2,048,334), 312.46 ($1,242,315), 315.45 ($40,217), 315.46 ($35,022), 311.40 ($13,216) and 345.81 ($2,232)

(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).

(D) Applicable depreciation rate is 3.0%, 2.2%, 3.7%, 3.5%, 3.3%, 2.5%, 3.3%, 3.1%, 3.5% , 2.9%, and 3.3%

(E) Line 9a x Line 10

(F) Line 9b x Line 11



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ECRC 2014 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 2014 to December 2014**



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 | |
| | c. Auction Proceeds/Other | | 0 | 0 | 0 | 597 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 597 |
| 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 | (36,660) | (36,436) | (36,436) | (36,436) | (36,241) | (36,241) | (36,241) | (36,033) | (36,033) | (36,033) | (35,777) | (35,777) | (35,777) | |
| 3. | Total Working Capital Balance | ($36,660) | (36,436) | (36,436) | (36,436) | (36,241) | (36,241) | (36,241) | (36,033) | (36,033) | (36,033) | (35,777) | (35,777) | (35,777) | |
| 4. | Average Net Working Capital Balance | | ($36,548) | ($36,436) | ($36,436) | ($36,338) | ($36,241) | ($36,241) | ($36,137) | ($36,033) | ($36,033) | ($35,905) | ($35,777) | ($35,777) | |
| 5. | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (A) | | (220) | (219) | (219) | (219) | (218) | (218) | (213) | (213) | (213) | (212) | (211) | (211) | (2,586) |
| | b. Debt Component Grossed Up For Taxes (B) | | (67) | (67) | (67) | (67) | (67) | (67) | (61) | (61) | (61) | (61) | (61) | (61) | (768) |
| 6. | Total Return Component | | (287) | (286) | (286) | (286) | (285) | (285) | (274) | (274) | (274) | (273) | (272) | (272) | (3,354) |
| 7. | Expenses: | | | | | | | | | | | | | | |
| | a. Gains | | 0 | 0 | 0 | (597) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (597) |
| | b. Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. $SO_2$ Allowance Expense | | (234) | (300) | 304 | 41 | 268 | 497 | 32 | 44 | 49 | (272) | (25) | 68 | 471 |
| 8. | Net Expenses (D) | | (234) | (300) | 304 | (556) | 268 | 497 | 32 | 44 | 49 | (272) | (25) | 68 | (126.57) |
| 9. | Total System Recoverable Expenses (Lines 6 + 8) | | (521) | (586) | 18 | (842) | (17) | 212 | (242) | (230) | (225) | (545) | (297) | (204) | (3,481) |
| | a. Recoverable Costs Allocated to Energy | | (521) | (586) | 18 | (842) | (17) | 212 | (242) | (230) | (225) | (545) | (297) | (204) | (3,481) |
| | b. Recoverable Costs 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) | | (521) | (586) | 18 | (842) | (17) | 212 | (242) | (230) | (225) | (545) | (297) | (204) | (3,479) |
| 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) | | ($521) | ($586) | $18 | ($842) | ($17) | $212 | ($242) | ($230) | ($225) | ($545) | ($297) | ($204) | ($3,479) |

**Notes:**

(A) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% x 1/12 (Jul-Dec).
(C) Line 6 is reported on Schedule 7A.
(D) Line 8 is reported on Schedule 5A.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.



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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**January 2014 to December 2014**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Gypsum Storage Facility
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $215,934 | $160,228 | $376,162 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20,803,036 | 160,228 | 20,963,264 |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other - AFUDC (excl from CWIP) | | 3,779,379 | 2,172,830 | 1,525,638 | (299,995) | 2,266,801 | 914,581 | 1,247,933 | 1,064,100 | 1,089,122 | 431,297 | 0 | 0 | 14,191,686 |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $20,803,036 | $20,963,264 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (50,274) | |
| 4. | 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 | 20,803,036 | 20,912,990 | |
| 6. | Average Net Investment | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 10,401,518 | 20,858,013 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 61,407 | 123,139 | $184,546 |
| | b. Debt Component Grossed Up For Taxes (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17,633 | 35,360 | 52,993 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50,274 | 50,274 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | 79,040 | 208,773 | 287,813 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 79,040 | 208,773 | 287,813 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 79,040 | 208,773 | 287,813 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $79,040 | $208,773 | $287,813 |

**Notes:**
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 7.2242% x 1/12 (Jan-Jun) and Line 6 x 7.0844% x1/12 (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 2.2101% x 1/12 (Jan-Jun) and Line 6 x 2.0343% 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 2014 to June 2014**



**Calculation of Revenue Requirement Rate of Return**
(In Dollars)

| | Jurisdictional Rate Base Actual May 2013 ($000) | (1) Adjusted per Rate Base Settlement * Jurisdictional Rate Base Actual May 2013 ($000) | (2) Ratio % | (3) Cost Rate % | (4) Weighted Cost Rate % |
|---|---|---|---|---|---|
| Long Term Debt | $ 1,425,239 | $ 1,413,339 | 36.69% | 5.78% | 2.1207% |
| Short Term Debt | 0 | 0 | 0.00% | 0.66% | 0.0000% |
| Preferred Stock | 0 | 0 | 0.00% | 0.00% | 0.0000% |
| Customer Deposits | 106,560 | 106,560 | 2.77% | 2.91% | 0.0806% |
| Common Equity | 1,647,409 | 1,659,309 | 43.08% | 10.25% | 4.4157% |
| Deferred ITC - Weighted Cost | 8,381 | 8,381 | 0.22% | 8.71% | 0.0192% |
| Accumulated Deferred Income Taxes | 664,214 | 664,214 | 17.24% | 0.00% | 0.0000% |
| Zero Cost ITCs | | | | | |
| Total | $ 3,851,803 | $ 3,851,803 | 100.00% | | 6.64% |

**ITC split between Debt and Equity:**

| | | | |
|---|---|---|---|
| Long Term Debt | $ 1,413,339 | Long Term Debt | 46.00% |
| Short Term Debt | 0 | Short Term Debt | 0.00% |
| Equity - Preferred | 0 | Equity - Preferred | 0.00% |
| Equity - Common | 1,659,309 | Equity - Common | 54.00% |
| Total | $ 3,072,648 | Total | 100.00% |

**Deferred ITC - Weighted Cost:**

| | |
|---|---|
| Debt = .0192% * 46.00% | 0.0088% |
| Equity = .0192% * 54.00% | 0.0104% |
| Weighted Cost | 0.0192% |

**Total Equity Cost Rate:**

| | |
|---|---|
| Preferred Stock | 0.0000% |
| Common Equity | 4.4157% |
| Deferred ITC - Weighted Cost | 0.0104% |
| | 4.4261% |
| Times Tax Multiplier | 1.632200 |
| Total Equity Component | 7.2242% |

**Total Debt Cost Rate:**

| | |
|---|---|
| Long Term Debt | 2.1207% |
| Short Term Debt | 0.0000% |
| Customer Deposits | 0.0806% |
| Deferred ITC - Weighted Cost | 0.0088% |
| Total Debt Component | 2.2101% |
| | 9.4343% |

**Notes:**

* Adjusted to 54% equity, per base rate settlement

Column (1) - From WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 rate base settlement ROE, tax multiplier and equity percentage.

Column (2) - Column (1) / Total Column (1)

Column (3) - From WACC Stipulation & Settlement Agreement Dated July 17, 2012,, and 2013 rate base settlement ROE, tax multiplier and equity percentage.

Column (4) - Column (2) x Column (3)

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
**July 2014 to December 2014**

Form 42 - 9A
Page 2 of 2

**Calculation of Revenue Requirement Rate of Return**
(In Dollars)

| | (1) Jurisdictional Rate Base Actual May 2014 ($000) | (2) Ratio % | (3) Cost Rate % | (4) Weighted Cost Rate % |
|---|---|---|---|---|
| Long Term Debt | $ 1,429,551 | 35.37% | 5.55% | 1.9630% |
| Short Term Debt | 25,222 | 0.62% | 0.61% | 0.0038% |
| Preferred Stock | 0 | 0.00% | 0.00% | 0.0000% |
| Customer Deposits | 107,785 | 2.67% | 2.25% | 0.0601% |
| Common Equity | 1,707,776 | 42.26% | 10.25% | 4.3317% |
| Deferred ITC - Weighted Cost | 8,027 | 0.20% | 8.05% | 0.0161% |
| Accumulated Deferred Income Taxes | 763,143 | 18.88% | 0.00% | 0.0000% |
| Zero Cost ITCs | | | | |
| Total | $ 4,041,504 | 100.00% | | 6.37% |

**ITC split between Debt and Equity:**

| | | | |
|---|---|---|---|
| Long Term Debt | $ 1,429,551 | Long Term Debt | 45.20% |
| Short Term Debt | 25,222 | Short Term Debt | 0.80% |
| Equity - Preferred | 0 | Equity - Preferred | 0.00% |
| Equity - Common | 1,707,776 | Equity - Common | 54.00% |
| Total | $ 3,162,549 | Total | 100.00% |

**Deferred ITC - Weighted Cost:**

| | |
|---|---|
| Debt = .0161% * 46.00% | 0.0074% |
| Equity = .0161% * 54.00% | 0.0087% |
| Weighted Cost | 0.0161% |

**Total Equity Cost Rate:**

| | |
|---|---|
| Preferred Stock | 0.0000% |
| Common Equity | 4.3317% |
| Deferred ITC - Weighted Cost | 0.0087% |
| | 4.3404% |
| Times Tax Multiplier | 1.632200 |
| Total Equity Component | 7.0844% |

**Total Debt Cost Rate:**

| | |
|---|---|
| Long Term Debt | 1.9630% |
| Short Term Debt | 0.0038% |
| Customer Deposits | 0.0601% |
| Deferred ITC - Weighted Cost | 0.0074% |
| Total Debt Component | 2.0343% |
| | 9.1187% |

**Notes:**

* Adjusted to 54% equity, per base rate settlement

Column (1) - From WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 rate base settlement ROE, tax multiplier and equity perce

Column (2) - Column (1) / Total Column (1)

Column (3) - From WACC Stipulation & Settlement Agreement Dated July 17, 2012,, and 2013 rate base settlement ROE, tax multiplier and equity perc

Column (4) - Column (2) x Column (3)

DOCKET NO. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2)

# INDEX

## TAMPA ELECTRIC COMPANY
## ENVIRONMENTAL COST RECOVERY CLAUSE

## ACTUAL / ESTIMATED TRUE-UP AMOUNT
## FOR THE PERIOD OF
## JANUARY 2015 THROUGH DECEMBER 2015

## FORMS 42-1E THROUGH 42-9E


| DOCUMENT NO. | TITLE | PAGE |
|---|---|---|
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| 2 | Form 42-2E | 12 |
| 3 | Form 42-3E | 13 |
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 22
PARTY: TAMPA ELECTRIC COMPANY (TECO) – (DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-2

**Tampa Electric Company** Form 42 - 1E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2015 to December 2015**
(in Dollars)

| Line | | Period Amount |
|---|---|---|
| 1. | Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5) | $4,529,263 |
| 2. | Interest Provision (Form 42-2E, Line 6) | 6,010 |
| 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 2016 to December 2016 (Lines 1 + 2 + 3) | $4,535,273 |



DOCKET NO. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 1, PAGE 1 OF 1

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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) | $5,651,676 | $5,285,880 | $5,413,142 | $6,085,000 | $6,509,236 | $7,216,835 | $7,351,719 | $7,257,057 | $7,467,758 | $6,739,743 | $5,655,851 | $5,476,631 | $76,110,528 |
| 2. True-Up Provision | 741,062 | 741,062 | 741,062 | 741,062 | 741,062 | 741,062 | 741,062 | 741,062 | 741,062 | 741,062 | 741,062 | 741,066 | 8,892,748 |
| 3. ECRC Revenues Applicable to Period (Lines 1 + 2) | 6,392,738 | 6,026,942 | 6,154,204 | 6,826,062 | 7,250,298 | 7,957,897 | 8,092,781 | 7,998,119 | 8,208,820 | 7,480,805 | 6,396,913 | 6,217,697 | 85,003,276 |
| 4. Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| a. O & M Activities (Form 42-5E, Line 9) | 2,276,795 | 1,920,574 | 1,722,232 | 1,774,138 | 2,590,735 | 2,578,233 | 2,220,446 | 1,984,182 | 2,328,057 | 2,000,755 | 2,129,976 | 1,735,531 | 25,261,654 |
| b. Capital Investment Projects (Form 42-7E, Line 9) | 4,661,016 | 4,652,145 | 4,641,288 | 4,630,349 | 4,622,606 | 4,616,363 | 4,569,909 | 4,566,159 | 4,560,050 | 4,557,898 | 4,563,415 | 4,571,161 | 55,212,359 |
| c. Total Jurisdictional ECRC Costs | 6,937,811 | 6,572,719 | 6,363,520 | 6,404,487 | 7,213,341 | 7,194,596 | 6,790,355 | 6,550,341 | 6,888,107 | 6,558,653 | 6,693,391 | 6,306,692 | 80,474,013 |
| 5. Over/Under Recovery (Line 3 - Line 4c) | (545,073) | (545,777) | (209,316) | 421,575 | 36,957 | 763,301 | 1,302,426 | 1,447,778 | 1,320,713 | 922,152 | (296,478) | (88,995) | 4,529,263 |
| 6. Interest Provision (Form 42-3E, Line 10) | 347 | 244 | 154 | 78 | 55 | 35 | 191 | 629 | 926 | 1,340 | 1,318 | 693 | 6,010 |
| 7. Beginning Balance True-Up & Interest Provision | 8,892,748 | 7,606,960 | 6,320,365 | 5,370,141 | 5,050,732 | 4,346,682 | 4,368,956 | 4,930,511 | 5,637,856 | 6,218,433 | 6,400,863 | 5,364,641 | 8,892,748 |
| a. Deferred True-Up from January to December 2014 | (3,915,636) | (3,915,636) | (3,915,636) | (3,915,636) | (3,915,636) | (3,915,636) | (3,915,636) | (3,915,636) | (3,915,636) | (3,915,636) | (3,915,636) | (3,915,636) | (3,915,636) |
| 8. True-Up Collected/(Refunded) (see Line 2) | (741,062) | (741,062) | (741,062) | (741,062) | (741,062) | (741,062) | (741,062) | (741,062) | (741,062) | (741,062) | (741,062) | (741,066) | (8,892,748) |
| 9. End of Period Total True-Up (Lines 5+6+7+7a+8) | 3,691,324 | 2,404,729 | 1,454,505 | 1,135,096 | 431,046 | 453,320 | 1,014,875 | 1,722,220 | 2,302,797 | 2,485,227 | 1,449,005 | 619,637 | 619,637 |
| 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) | $3,691,324 | $2,404,729 | $1,454,505 | $1,135,096 | $431,046 | $453,320 | $1,014,875 | $1,722,220 | $2,302,797 | $2,485,227 | $1,449,005 | $619,637 | $619,637 |

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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) | $4,977,112 | $3,691,324 | $2,404,729 | $1,454,505 | $1,135,096 | $431,046 | $453,320 | $1,014,875 | $1,722,220 | $2,302,797 | $2,485,227 | $1,449,005 | |
| 2. | Ending True-Up Amount Before Interest | 3,690,977 | 2,404,485 | 1,454,351 | 1,135,018 | 430,991 | 453,285 | 1,014,684 | 1,721,591 | 2,301,871 | 2,483,887 | 1,447,687 | 618,944 | |
| 3. | Total of Beginning & Ending True-Up (Lines 1 + 2) | 8,668,089 | 6,095,809 | 3,859,080 | 2,589,523 | 1,566,087 | 884,331 | 1,468,004 | 2,736,466 | 4,024,091 | 4,786,684 | 3,932,914 | 2,067,949 | |
| 4. | Average True-Up Amount (Line 3 x 1/2) | 4,334,045 | 3,047,905 | 1,929,540 | 1,294,762 | 783,044 | 442,166 | 734,002 | 1,368,233 | 2,012,046 | 2,393,342 | 1,966,457 | 1,033,975 | |
| 5. | Interest Rate (First Day of Reporting Business Month) | 0.10% | 0.10% | 0.09% | 0.09% | 0.06% | 0.10% | 0.08% | 0.55% | 0.55% | 0.55% | 0.80% | 0.80% | |
| 6. | Interest Rate (First Day of Subsequent Business Month) | 0.10% | 0.09% | 0.09% | 0.06% | 0.10% | 0.08% | 0.55% | 0.55% | 0.55% | 0.80% | 0.80% | 0.80% | |
| 7. | Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 0.20% | 0.19% | 0.18% | 0.15% | 0.16% | 0.18% | 0.63% | 1.10% | 1.10% | 1.35% | 1.60% | 1.60% | |
| 8. | Average Interest Rate (Line 7 x 1/2) | 0.100% | 0.095% | 0.090% | 0.075% | 0.080% | 0.090% | 0.315% | 0.550% | 0.550% | 0.675% | 0.800% | 0.800% | |
| 9. | Monthly Average Interest Rate (Line 8 x 1/12) | 0.008% | 0.008% | 0.008% | 0.006% | 0.007% | 0.008% | 0.026% | 0.046% | 0.046% | 0.056% | 0.067% | 0.067% | |
| 10. | Interest Provision for the Month (Line 4 x Line 9) | $347 | $244 | $154 | $78 | $55 | $35 | $191 | $629 | $926 | $1,340 | $1,318 | $693 | $6,010 |



DOCKET NO. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 3, PAGE 1 OF 1

**Tampa Electric Company** Form 42 - 4E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

**Variance Report of O & M Activities**
(In Dollars)

| Line | | (1) Actual/Estimated | (2) Original Projection | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1. | Description of O&M Activities | | | | |
| | a. Big Bend Unit 3 Flue Gas Desulfurization Integration | $5,607,172 | $6,245,680 | ($638,508) | -10.2% |
| | b. Big Bend Units 1 & 2 Flue Gas Conditioning | - | - | - | 0.0% |
| | c. $SO_2$ Emissions Allowances | 15,198 | 26,128 | (10,930) | -41.8% |
| | d. Big Bend Units 1 & 2 FGD | 8,789,921 | 10,189,162 | (1,399,241) | -13.7% |
| | e. Big Bend PM Minimization and Monitoring | 904,608 | 840,000 | 64,608 | 7.7% |
| | f. Big Bend $NO_x$ Emissions Reduction | 109,491 | 120,000 | (10,509) | -8.8% |
| | g. NPDES Annual Surveillance Fees | 34,500 | 34,500 | - | 0.0% |
| | h. Gannon Thermal Discharge Study | - | - | - | 0.0% |
| | i. Polk $NO_x$ Emissions Reduction | 10,321 | 20,000 | (9,679) | -48.4% |
| | j. Bayside SCR Consumables | 150,590 | 145,000 | 5,590 | 3.9% |
| | k. Big Bend Unit 4 SOFA | 24,000 | 48,000 | (24,000) | -50.0% |
| | l. Big Bend Unit 1 Pre-SCR | 128,649 | 138,000 | (9,351) | -6.8% |
| | m. Big Bend Unit 2 Pre-SCR | 52,505 | 48,000 | 4,505 | 9.4% |
| | n. Big Bend Unit 3 Pre-SCR | 24,000 | 48,000 | (24,000) | -50.0% |
| | o. Clean Water Act Section 316(b) Phase II Study | 370,652 | 960,000 | (589,348) | -61.4% |
| | p. Arsenic Groundwater Standard Program | 57,560 | 300,000 | (242,440) | -80.8% |
| | q. Big Bend 1 SCR | 2,347,505 | 2,164,529 | 182,976 | 8.5% |
| | r. Big Bend 2 SCR | 1,878,619 | 2,499,555 | (620,936) | -24.8% |
| | s. Big Bend 3 SCR | 2,230,792 | 2,023,711 | 207,081 | 10.2% |
| | t. Big Bend 4 SCR | 1,172,664 | 1,111,949 | 60,715 | 5.5% |
| | u. Mercury Air Toxics Standards | 183,392 | 230,000 | (46,608) | -20.3% |
| | v. Greenhouse Gas Reduction Program | 97,411 | 90,000 | 7,411 | 8.2% |
| | w. Big Bend Gypsum Storage Facility | 1,072,105 | 1,284,000 | (211,895) | -16.5% |
| 2. | Total Investment Projects - Recoverable Costs | $25,261,654 | $28,566,214 | ($3,304,559) | -11.6% |
| 3. | Recoverable Costs Allocated to Energy | $24,798,943 | $27,271,714 | ($2,472,771) | -9.1% |
| 4. | Recoverable Costs Allocated to Demand | $462,711 | $1,294,500 | ($831,788) | -64.3% |

**Notes:**

Column (1) is the End of Period Totals on Form 42-5E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-14-0643-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)



DOCKET NO. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 4, PAGE 1 OF 1

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 Flue Gas Desulfurization Integration | $383,586 | $347,546 | $389,623 | $458,524 | $744,677 | $572,916 | $455,750 | $468,750 | $455,750 | $429,750 | $450,150 | $450,150 | $5,607,172 | | $5,607,172 |
| | 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 | (144) | 30 | 58 | (130) | 70 | 95 | 2,556 | 2,538 | 2,550 | 2,582 | 2,521 | 2,472 | 15,198 | | 15,198 |
| | d. Big Bend Units 1 & 2 FGD | 459,746 | 727,708 | 657,506 | 813,413 | 1,043,833 | 1,090,810 | 816,904 | 578,823 | 900,672 | 661,765 | 747,290 | 291,451 | 8,789,921 | | 8,789,921 |
| | e. Big Bend PM Minimization and Monitoring | 117,649 | 70,805 | 72,987 | 41,714 | 89,502 | 61,951 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 904,608 | | 904,608 |
| | f. Big Bend $NO_x$ Emissions Reduction | 3,371 | 2,402 | 5,048 | 31 | 10,320 | 28,319 | 0 | 0 | 30,000 | 30,000 | 0 | 0 | 109,491 | | 109,491 |
| | 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 | 391.55 | 929.29 | 0 | 0 | 0 | 0 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 10,321 | | 10,321 |
| | j. Bayside SCR and Ammonia | 0 | 13,380 | 12,059 | 12,926 | 12,080 | 22,146 | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 150,590 | | 150,590 |
| | k. Big Bend Unit 4 SOFA | 0 | 0 | 0 | 0 | 0 | 0 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 24,000 | | 24,000 |
| | l. Big Bend Unit 1 Pre-SCR | 800 | 0 | 7,909 | 815 | 3,134 | 1,991 | 4,000 | 24,000 | 39,000 | 39,000 | 4,000 | 4,000 | 128,649 | | 128,649 |
| | m. Big Bend Unit 2 Pre-SCR | 0 | 5,828 | 6,423 | 12,725 | 0 | 3,528 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 52,505 | | 52,505 |
| | n. Big Bend Unit 3 Pre-SCR | 0 | 0 | 0 | 3,077 | (3,077) | 0 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 24,000 | | 24,000 |
| | o. Clean Water Act Section 316(b) Phase II Study | 0 | 2 | 8 | 642 | 0 | 0 | 10,000 | 40,000 | 80,000 | 80,000 | 80,000 | 80,000 | 370,652 | 370,652 | |
| | p. Arsenic Groundwater Standard Program | 62 | (2,686) | 55 | 46 | 38 | 45 | 0 | 0 | 60,000 | 0 | 0 | 0 | 57,560 | 57,560 | |
| | q. Big Bend 1 SCR | 256,300 | 307,333 | 253,181 | 148,925 | 200,385 | 260,894 | 221,115 | 172,617 | 45,000 | 50,610 | 210,170 | 220,976 | 2,347,505 | | 2,347,505 |
| | r. Big Bend 2 SCR | 197,112 | 33,361 | 67,253 | 59,460 | 116,288 | 127,306 | 218,097 | 222,125 | 225,171 | 193,996 | 203,414 | 215,035 | 1,878,619 | | 1,878,619 |
| | s. Big Bend 3 SCR | 469,047 | 105,551 | 47,859 | 98,352 | 214,801 | 255,010 | 176,668 | 180,045 | 182,448 | 191,832 | 137,914 | 171,265 | 2,230,792 | | 2,230,792 |
| | t. Big Bend 4 SCR | 251,370 | 115,299 | 59,864 | 40,244 | 68,477 | 70,634 | 92,107 | 92,784 | 94,217 | 98,720 | 91,267 | 97,682 | 1,172,664 | | 1,172,664 |
| | u. Mercury Air Toxics Standards | 0 | 203 | 49,311 | 5,152 | 247 | 10,229 | 31,750 | 11,000 | 21,750 | 31,000 | 11,750 | 11,000 | 183,392 | | 183,392 |
| | v. Greenhouse Gas Reduction Program | 61 | 90,000 | 7,805 | 0 | (455) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 97,411 | | 97,411 |
| | w. Big Bend Gypsum Storage Facility | 102,943 | 102,884 | 85,284 | 78,220 | 90,415 | 72,359 | 90,000 | 90,000 | 90,000 | 90,000 | 90,000 | 90,000 | 1,072,105 | | 1,072,105 |
| 2. | Total of O&M Activities | 2,276,795 | 1,920,574.00 | 1,722,232 | 1,774,138 | 2,590,735.00 | 2,578,233 | 2,220,446 | 1,984,182 | 2,328,057 | 2,000,755 | 2,129,976 | 1,735,531 | 25,261,654 | $462,711 | $24,798,943 |
| 3. | Recoverable Costs Allocated to Energy | 2,242,233 | 1,923,258 | 1,722,170 | 1,773,450 | 2,590,697 | 2,578,188 | 2,210,446 | 1,944,182 | 2,188,057 | 1,920,755 | 2,049,976 | 1,655,531 | 24,798,943 | | |
| 4. | Recoverable Costs Allocated to Demand | 34,562 | (2,684) | 62 | 688 | 38 | 45 | 10,000 | 40,000 | 140,000 | 80,000 | 80,000 | 80,000 | 462,711 | | |
| 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) | 2,242,233 | 1,923,258 | 1,722,170 | 1,773,450 | 2,590,697 | 2,578,188 | 2,210,446 | 1,944,182 | 2,188,057 | 1,920,755 | 2,049,976 | 1,655,531 | 24,798,943 | | |
| 8. | Jurisdictional Demand Recoverable Costs (B) | 34,562 | (2,684) | 62 | 688 | 38 | 45 | 10,000 | 40,000 | 140,000 | 80,000 | 80,000 | 80,000 | 462,711 | | |
| 9. | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $2,276,795 | $1,920,574 | $1,722,232 | $1,774,138 | $2,590,735 | $2,578,233 | $2,220,446 | $1,984,182 | $2,328,057 | $2,000,755 | $2,129,976 | $1,735,531 | $25,261,654 | | |

**Notes:**
(A) Line 3 x Line 5
(B) Line 4 x Line 6



DOCKET NO. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 5, PAGE 1 OF 1

**Tampa Electric Company** Form 42 - 6E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

**Variance Report of Capital Investment Projects - Recoverable Costs**
(In Dollars)

| Line | | (1) Actual/Estimated | (2) Original Projection | (3) Variance Amount | (4) Percent |
|---|---|---|---|---|---|
| 1. | Description of Investment Projects | | | | |
| | a. Big Bend Unit 3 Flue Gas Desulfurization Integration | $1,164,812 | $1,163,997 | $815 | 0.1% |
| | b. Big Bend Units 1 & 2 Flue Gas Conditioning | 313,558 | 314,305 | (747) | -0.2% |
| | c. Big Bend Unit 4 Continuous Emissions Monitors | 63,363 | 63,588 | (225) | -0.4% |
| | d. Big Bend Fuel Oil Tank # 1 Upgrade | 41,016 | 41,168 | (152) | -0.4% |
| | e. Big Bend Fuel Oil Tank # 2 Upgrade | 67,457 | 67,712 | (255) | -0.4% |
| | f. Big Bend Unit 1 Classifier Replacement | 100,325 | 100,625 | (300) | -0.3% |
| | g. Big Bend Unit 2 Classifier Replacement | 72,408 | 72,634 | (226) | -0.3% |
| | h. Big Bend Section 114 Mercury Testing Platform | 10,535 | 10,579 | (44) | -0.4% |
| | i. Big Bend Units 1 & 2 FGD | 7,284,957 | 7,503,897 | (218,940) | -2.9% |
| | j. Big Bend FGD Optimization and Utilization | 1,839,605 | 1,847,903 | (8,298) | -0.4% |
| | k. Big Bend $NO_x$ Emissions Reduction | 608,606 | 611,733 | (3,127) | -0.5% |
| | l. Big Bend PM Minimization and Monitoring | 1,846,455 | 1,792,308 | 54,147 | 3.0% |
| | m. Polk $NO_x$ Emissions Reduction | 139,869 | 140,423 | (554) | -0.4% |
| | n. Big Bend Unit 4 SOFA | 243,592 | 244,659 | (1,067) | -0.4% |
| | o. Big Bend Unit 1 Pre-SCR | 170,018 | 170,683 | (665) | -0.4% |
| | p. Big Bend Unit 2 Pre-SCR | 161,262 | 161,919 | (657) | -0.4% |
| | q. Big Bend Unit 3 Pre-SCR | 286,881 | 288,104 | (1,223) | -0.4% |
| | r. Big Bend Unit 1 SCR | 9,703,343 | 9,741,516 | (38,173) | -0.4% |
| | s. Big Bend Unit 2 SCR | 10,278,852 | 10,220,155 | 58,697 | 0.6% |
| | t. Big Bend Unit 3 SCR | 8,397,829 | 8,546,448 | (148,619) | -1.7% |
| | u. Big Bend Unit 4 SCR | 6,392,540 | 6,404,385 | (11,845) | -0.2% |
| | v. Big Bend FGD System Reliability | 2,543,372 | 2,555,739 | (12,367) | -0.5% |
| | w. Mercury Air Toxics Standards | 981,575 | 971,990 | 9,585 | 1.0% |
| | x. $S0_2$ Emissions Allowances | (3,214) | (3,226) | 12 | -0.4% |
| | y. Big Bend Gypsum Storage Facility | 2,503,343 | 2,807,047 | (303,704) | -10.8% |
| 2. | Total Investment Projects - Recoverable Costs | $55,212,359 | $55,840,291 | ($627,932) | -1.1% |
| 3. | Recoverable Costs Allocated to Energy | $55,103,886 | $55,731,411 | ($627,525) | -1.1% |
| 4. | Recoverable Costs Allocated to Demand | $108,473 | $108,880 | ($407) | -0.4% |

**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-14-0643-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)



DOCKET NO. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 6, PAGE 1 OF 1

Form 42-7E

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

**Capital Investment Projects-Recoverable Costs**

(in Dollars)

| Line | Description (A) | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimate July | Estimate August | Estimate September | Estimate October | Estimate November | Estimate December | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. a. | Big Bend Unit 3 Flue Gas Desulfurization Integration | $98,209 | $98,182 | $98,078 | $97,932 | $97,806 | $97,649 | $96,584 | $96,433 | $96,279 | $96,096 | $95,887 | $95,677 | $1,164,812 | | $1,164,812 |
| b. | Big Bend Units 1 and 2 Flue Gas Conditioning | 26,867 | 26,744 | 26,621 | 26,499 | 26,376 | 26,253 | 26,002 | 25,881 | 25,760 | 25,640 | 25,518 | 25,397 | 313,558 | | 313,558 |
| c. | Big Bend Unit 4 Continuous Emissions Monitors | 5,395 | 5,378 | 5,361 | 5,343 | 5,326 | 5,308 | 5,252 | 5,235 | 5,217 | 5,200 | 5,182 | 5,166 | 63,363 | | 63,363 |
| d. | Big Bend Fuel Oil Tank # 1 Upgrade | 3,490 | 3,479 | 3,468 | 3,458 | 3,446 | 3,436 | 3,399 | 3,389 | 3,379 | 3,368 | 3,357 | 3,347 | 41,016 | $41,016 | |
| e. | Big Bend Fuel Oil Tank # 2 Upgrade | 5,739 | 5,722 | 5,704 | 5,686 | 5,669 | 5,651 | 5,591 | 5,574 | 5,556 | 5,539 | 5,522 | 5,504 | 67,457 | 67,457 | |
| f. | Big Bend Unit 1 Classifier Replacement | 8,569 | 8,535 | 8,502 | 8,468 | 8,435 | 8,403 | 8,318 | 8,285 | 8,252 | 8,219 | 8,186 | 8,153 | 100,325 | | 100,325 |
| g. | Big Bend Unit 2 Classifier Replacement | 6,179 | 6,156 | 6,134 | 6,111 | 6,088 | 6,065 | 6,003 | 5,980 | 5,957 | 5,934 | 5,912 | 5,889 | 72,408 | | 72,408 |
| h. | Big Bend Section 114 Mercury Testing Platform | 894 | 892 | 889 | 887 | 885 | 883 | 873 | 871 | 869 | 866 | 864 | 862 | 10,535 | | 10,535 |
| i. | Big Bend Units 1 & 2 FGD | 616,852 | 615,041 | 613,136 | 611,220 | 609,278 | 607,328 | 600,899 | 599,087 | 597,356 | 600,736 | 607,989 | 606,035 | 7,284,957 | | 7,284,957 |
| j. | Big Bend FGD Optimization and Utilization | 155,884 | 155,540 | 155,196 | 154,852 | 154,508 | 154,164 | 152,426 | 152,086 | 151,747 | 151,407 | 151,068 | 150,727 | 1,839,605 | | 1,839,605 |
| k. | Big Bend $NO_x$ Emissions Reduction | 51,404 | 51,326 | 51,248 | 51,171 | 51,094 | 51,016 | 50,416 | 50,339 | 50,263 | 50,186 | 50,110 | 50,033 | 608,606 | | 608,606 |
| l. | Big Bend PM Minimization and Monitoring | 146,155 | 146,088 | 146,137 | 146,299 | 146,581 | 147,285 | 147,662 | 152,531 | 157,869 | 161,485 | 164,410 | 183,953 | 1,846,455 | | 1,846,455 |
| m. | Polk $NO_x$ Emissions Reduction | 11,887 | 11,853 | 11,820 | 11,786 | 11,753 | 11,718 | 11,592 | 11,558 | 11,525 | 11,492 | 11,459 | 11,426 | 139,869 | | 139,869 |
| n. | Big Bend Unit 4 SOFA | 20,656 | 20,607 | 20,558 | 20,509 | 20,462 | 20,413 | 20,184 | 20,136 | 20,089 | 20,040 | 19,993 | 19,945 | 243,592 | | 243,592 |
| o. | Big Bend Unit 1 Pre-SCR | 14,453 | 14,412 | 14,369 | 14,328 | 14,286 | 14,244 | 14,091 | 14,050 | 14,008 | 13,967 | 13,926 | 13,884 | 170,018 | | 170,018 |
| p. | Big Bend Unit 2 Pre-SCR | 13,697 | 13,660 | 13,623 | 13,586 | 13,549 | 13,511 | 13,364 | 13,328 | 13,291 | 13,254 | 13,218 | 13,181 | 161,262 | | 161,262 |
| q. | Big Bend Unit 3 Pre-SCR | 24,341 | 24,281 | 24,220 | 24,160 | 24,099 | 24,039 | 23,773 | 23,713 | 23,653 | 23,593 | 23,534 | 23,475 | 286,881 | | 286,881 |
| r. | Big Bend Unit 1 SCR | 824,713 | 822,364 | 820,015 | 817,666 | 815,317 | 812,968 | 804,181 | 801,862 | 799,543 | 797,224 | 794,904 | 792,586 | 9,703,343 | | 9,703,343 |
| s. | Big Bend Unit 2 SCR | 866,209 | 865,801 | 863,548 | 861,273 | 861,839 | 862,777 | 853,698 | 851,425 | 849,188 | 846,951 | 849,226 | 846,917 | 10,278,852 | | 10,278,852 |
| t. | Big Bend Unit 3 SCR | 713,051 | 711,170 | 709,289 | 707,408 | 705,527 | 703,646 | 695,932 | 694,075 | 692,218 | 690,362 | 688,504 | 686,647 | 8,397,829 | | 8,397,829 |
| u. | Big Bend Unit 4 SCR | 540,292 | 538,957 | 537,643 | 536,348 | 535,033 | 533,698 | 529,399 | 530,954 | 529,594 | 528,234 | 526,874 | 525,514 | 6,392,540 | | 6,392,540 |
| v. | Big Bend FGD System Reliability | 215,122 | 214,732 | 214,343 | 213,953 | 213,563 | 213,173 | 210,710 | 210,325 | 209,940 | 209,555 | 209,170 | 208,786 | 2,543,372 | | 2,543,372 |
| w. | Mercury Air Toxics Standards | 81,509 | 81,364 | 81,231 | 81,171 | 81,655 | 82,767 | 81,882 | 81,723 | 81,561 | 81,999 | 82,437 | 82,276 | 981,575 | | 981,575 |
| y. | $SO_2$ Emissions Allowances (B) | (271) | (270) | (270) | (270) | (270) | (270) | (267) | (267) | (265) | (265) | (265) | (264) | (3,214) | | (3,214) |
| z. | Big Bend Gypsum Storage Facility | 209,720 | 210,131 | 210,425 | 210,505 | 210,301 | 210,238 | 207,945 | 207,586 | 207,201 | 206,816 | 206,430 | 206,045 | 2,503,343 | | 2,503,343 |
| 2. | Total Investment Projects - Recoverable Costs | 4,661,016 | 4,652,145 | 4,641,288 | 4,630,349 | 4,622,606 | 4,616,363 | 4,569,909 | 4,566,159 | 4,560,050 | 4,557,898 | 4,563,415 | 4,571,161 | 55,212,359 | $108,473 | $55,103,886 |
| 3. | Recoverable Costs Allocated to Energy | 4,651,787 | 4,642,944 | 4,632,116 | 4,621,205 | 4,613,491 | 4,607,276 | 4,560,919 | 4,557,196 | 4,551,115 | 4,548,991 | 4,554,536 | 4,562,310 | 55,103,886 | | 55,103,886 |
| 4. | Recoverable Costs Allocated to Demand | 9,229 | 9,201 | 9,172 | 9,144 | 9,115 | 9,087 | 8,990 | 8,963 | 8,935 | 8,907 | 8,879 | 8,851 | 108,473 | 108,473 | |
| 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) | 4,651,787 | 4,642,944 | 4,632,116 | 4,621,205 | 4,613,491 | 4,607,276 | 4,560,919 | 4,557,196 | 4,551,115 | 4,548,991 | 4,554,536 | 4,562,310 | 55,103,886 | | |
| 8. | Jurisdictional Demand Recoverable Costs (D) | 9,229 | 9,201 | 9,172 | 9,144 | 9,115 | 9,087 | 8,990 | 8,963 | 8,935 | 8,907 | 8,879 | 8,851 | 108,473 | | |
| 9. | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $4,661,016 | $4,652,145 | $4,641,288 | $4,630,349 | $4,622,606 | $4,616,363 | $4,569,909 | $4,566,159 | $4,560,050 | $4,557,898 | $4,563,415 | $4,571,161 | $55,212,359 | | |

**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



DOCKET NO. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 7, PAGE 1 OF 1

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimate July | Estimate August | Estimate September | Estimate October | Estimate November | Estimate December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $27,809 | $21,113 | $7,639 | $9,849 | $13,142 | $1,349 | $8,955 | $7,060 | $7,575 | $0 | $0 | $0 | $104,491 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 321,633 | 321,633 |
| | 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) | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,435,775 | $13,757,409 | |
| 3. | Less: Accumulated Depreciation | (4,412,355) | (4,440,346) | (4,468,337) | (4,496,328) | (4,524,319) | (4,552,310) | (4,580,301) | (4,608,292) | (4,636,283) | (4,664,274) | (4,692,265) | (4,720,256) | (4,748,247) | |
| 4. | CWIP - Non-Interest Bearing | 217,142 | 244,951 | 266,063 | 273,702 | 283,552 | 296,694 | 298,043 | 306,998 | 314,058 | 321,633 | 321,633 | 321,633 | (0) | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $9,240,561 | 9,240,379 | 9,233,501 | 9,213,149 | 9,195,007 | 9,180,158 | 9,153,517 | 9,134,481 | 9,113,550 | 9,093,134 | 9,065,143 | 9,037,152 | 9,009,162 | |
| 6. | Average Net Investment | | 9,240,470 | 9,236,940 | 9,223,325 | 9,204,078 | 9,187,583 | 9,166,838 | 9,143,999 | 9,124,015 | 9,103,342 | 9,079,138 | 9,051,147 | 9,023,157 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $54,553 | $54,532 | $54,451 | $54,338 | $54,240 | $54,118 | $53,755 | $53,637 | $53,516 | $53,373 | $53,209 | $53,044 | $646,766 |
| | b. Debt Component Grossed Up For Taxes (C) | | 15,665 | 15,659 | 15,636 | 15,603 | 15,575 | 15,540 | 14,838 | 14,805 | 14,772 | 14,732 | 14,687 | 14,642 | 182,154 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $27,991 | $27,991 | $27,991 | $27,991 | $27,991 | $27,991 | $27,991 | $27,991 | $27,991 | $27,991 | $27,991 | $27,991 | $335,892 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 98,209 | 98,182 | 98,078 | 97,932 | 97,806 | 97,649 | 96,584 | 96,433 | 96,279 | 96,096 | 95,887 | 95,677 | 1,164,812 |
| | a. Recoverable Costs Allocated to Energy | | 98,209 | 98,182 | 98,078 | 97,932 | 97,806 | 97,649 | 96,584 | 96,433 | 96,279 | 96,096 | 95,887 | 95,677 | 1,164,812 |
| | b. Recoverable Costs 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) | | 98,209 | 98,182 | 98,078 | 97,932 | 97,806 | 97,649 | 96,584 | 96,433 | 96,279 | 96,096 | 95,887 | 95,677 | 1,164,812 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $98,209 | $98,182 | $98,078 | $97,932 | $97,806 | $97,649 | $96,584 | $96,433 | $96,279 | $96,096 | $95,887 | $95,677 | $1,164,812 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 8,
PAGE 1 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | (3,598,202) | (3,614,343) | (3,630,484) | (3,646,625) | (3,662,766) | (3,678,907) | (3,695,048) | (3,711,189) | (3,727,330) | (3,743,471) | (3,759,612) | (3,775,753) | (3,791,894) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,419,532 | 1,403,391 | 1,387,250 | 1,371,109 | 1,354,968 | 1,338,827 | 1,322,686 | 1,306,545 | 1,290,404 | 1,274,263 | 1,258,122 | 1,241,981 | 1,225,840 | |
| 6. | Average Net Investment | | 1,411,462 | 1,395,321 | 1,379,180 | 1,363,039 | 1,346,898 | 1,330,757 | 1,314,616 | 1,298,475 | 1,282,334 | 1,266,193 | 1,250,052 | 1,233,911 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $8,333 | $8,238 | $8,142 | $8,047 | $7,952 | $7,856 | $7,728 | $7,633 | $7,538 | $7,444 | $7,349 | $7,254 | $93,514 |
| | b. Debt Component Grossed Up For Taxes (C) | | 2,393 | 2,365 | 2,338 | 2,311 | 2,283 | 2,256 | 2,133 | 2,107 | 2,081 | 2,055 | 2,028 | 2,002 | 26,352 |
| 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) | | 26,867 | 26,744 | 26,621 | 26,499 | 26,376 | 26,253 | 26,002 | 25,881 | 25,760 | 25,640 | 25,518 | 25,397 | 313,558 |
| | a. Recoverable Costs Allocated to Energy | | 26,867 | 26,744 | 26,621 | 26,499 | 26,376 | 26,253 | 26,002 | 25,881 | 25,760 | 25,640 | 25,518 | 25,397 | 313,558 |
| | 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 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 26,867 | 26,744 | 26,621 | 26,499 | 26,376 | 26,253 | 26,002 | 25,881 | 25,760 | 25,640 | 25,518 | 25,397 | 313,558 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $26,867 | $26,744 | $26,621 | $26,499 | $26,376 | $26,253 | $26,002 | $25,881 | $25,760 | $25,640 | $25,518 | $25,397 | $313,558 |

**Notes:**
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | (459,005) | (461,315) | (463,625) | (465,935) | (468,245) | (470,555) | (472,865) | (475,175) | (477,485) | (479,795) | (482,105) | (484,415) | (486,725) | |
| 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) | $407,206 | 404,896 | 402,586 | 400,276 | 397,966 | 395,656 | 393,346 | 391,036 | 388,726 | 386,416 | 384,106 | 381,796 | 379,486 | |
| 6. | Average Net Investment | | 406,051 | 403,741 | 401,431 | 399,121 | 396,811 | 394,501 | 392,191 | 389,881 | 387,571 | 385,261 | 382,951 | 380,641 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $2,397 | $2,384 | $2,370 | $2,356 | $2,343 | $2,329 | $2,306 | $2,292 | $2,278 | $2,265 | $2,251 | $2,238 | $27,809 |
| | b. Debt Component Grossed Up For Taxes (C) | | 688 | 684 | 681 | 677 | 673 | 669 | 636 | 633 | 629 | 625 | 621 | 618 | 7,834 |
| 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) | | 5,395 | 5,378 | 5,361 | 5,343 | 5,326 | 5,308 | 5,252 | 5,235 | 5,217 | 5,200 | 5,182 | 5,166 | 63,363 |
| | a. Recoverable Costs Allocated to Energy | | 5,395 | 5,378 | 5,361 | 5,343 | 5,326 | 5,308 | 5,252 | 5,235 | 5,217 | 5,200 | 5,182 | 5,166 | 63,363 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 5,395 | 5,378 | 5,361 | 5,343 | 5,326 | 5,308 | 5,252 | 5,235 | 5,217 | 5,200 | 5,182 | 5,166 | 63,363 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $5,395 | $5,378 | $5,361 | $5,343 | $5,326 | $5,308 | $5,252 | $5,235 | $5,217 | $5,200 | $5,182 | $5,166 | $63,363 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimate July | Estimate August | Estimate September | Estimate October | Estimate November | Estimate December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $497,578 | $497,578 | $497,578 | $497,578 | $497,578 | $497,578 | $497,578 | $497,578 | $497,578 | $497,578 | $497,578 | $497,578 | $497,578 | |
| 3. | Less: Accumulated Depreciation | (223,192) | (224,602) | (226,012) | (227,422) | (228,832) | (230,242) | (231,652) | (233,062) | (234,472) | (235,882) | (237,292) | (238,702) | (240,112) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $274,386 | 272,976 | 271,566 | 270,156 | 268,746 | 267,336 | 265,926 | 264,516 | 263,106 | 261,696 | 260,286 | 258,876 | 257,466 | |
| 6. | Average Net Investment | | 273,681 | 272,271 | 270,861 | 269,451 | 268,041 | 266,631 | 265,221 | 263,811 | 262,401 | 260,991 | 259,581 | 258,171 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $1,616 | $1,607 | $1,599 | $1,591 | $1,582 | $1,574 | $1,559 | $1,551 | $1,543 | $1,534 | $1,526 | $1,518 | $18,800 |
| | b. Debt Component Grossed Up For Taxes (C) | | 464 | 462 | 459 | 457 | 454 | 452 | 430 | 428 | 426 | 424 | 421 | 419 | 5,296 |
| 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) | | 3,490 | 3,479 | 3,468 | 3,458 | 3,446 | 3,436 | 3,399 | 3,389 | 3,379 | 3,368 | 3,357 | 3,347 | 41,016 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 3,490 | 3,479 | 3,468 | 3,458 | 3,446 | 3,436 | 3,399 | 3,389 | 3,379 | 3,368 | 3,357 | 3,347 | 41,016 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 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) | | 3,490 | 3,479 | 3,468 | 3,458 | 3,446 | 3,436 | 3,399 | 3,389 | 3,379 | 3,368 | 3,357 | 3,347 | 41,016 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $3,490 | $3,479 | $3,468 | $3,458 | $3,446 | $3,436 | $3,399 | $3,389 | $3,379 | $3,368 | $3,357 | $3,347 | $41,016 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimate July | Estimate August | Estimate September | Estimate October | Estimate November | Estimate December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $818,401 | $818,401 | $818,401 | $818,401 | $818,401 | $818,401 | $818,401 | $818,401 | $818,401 | $818,401 | $818,401 | $818,401 | $818,401 | |
| 3. | Less: Accumulated Depreciation | (367,108) | (369,427) | (371,746) | (374,065) | (376,384) | (378,703) | (381,022) | (383,341) | (385,660) | (387,979) | (390,298) | (392,617) | (394,936) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $451,293 | 448,974 | 446,655 | 444,336 | 442,017 | 439,698 | 437,379 | 435,060 | 432,741 | 430,422 | 428,103 | 425,784 | 423,465 | |
| 6. | Average Net Investment | | 450,134 | 447,815 | 445,496 | 443,177 | 440,858 | 438,539 | 436,220 | 433,901 | 431,582 | 429,263 | 426,944 | 424,625 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $2,657 | $2,644 | $2,630 | $2,616 | $2,603 | $2,589 | $2,564 | $2,551 | $2,537 | $2,523 | $2,510 | $2,496 | $30,920 |
| | b. Debt Component Grossed Up For Taxes (C) | | 763 | 759 | 755 | 751 | 747 | 743 | 708 | 704 | 700 | 697 | 693 | 689 | 8,709 |
| 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) | | 5,739 | 5,722 | 5,704 | 5,686 | 5,669 | 5,651 | 5,591 | 5,574 | 5,556 | 5,539 | 5,522 | 5,504 | 67,457 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 5,739 | 5,722 | 5,704 | 5,686 | 5,669 | 5,651 | 5,591 | 5,574 | 5,556 | 5,539 | 5,522 | 5,504 | 67,457 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 5,739 | 5,722 | 5,704 | 5,686 | 5,669 | 5,651 | 5,591 | 5,574 | 5,556 | 5,539 | 5,522 | 5,504 | 67,457 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $5,739 | $5,722 | $5,704 | $5,686 | $5,669 | $5,651 | $5,591 | $5,574 | $5,556 | $5,539 | $5,522 | $5,504 | $67,457 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | (763,880) | (768,268) | (772,656) | (777,044) | (781,432) | (785,820) | (790,208) | (794,596) | (798,984) | (803,372) | (807,760) | (812,148) | (816,536) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $552,377 | 547,989 | 543,601 | 539,213 | 534,825 | 530,437 | 526,049 | 521,661 | 517,273 | 512,885 | 508,497 | 504,109 | 499,721 | |
| 6. | Average Net Investment | | 550,183 | 545,795 | 541,407 | 537,019 | 532,631 | 528,243 | 523,855 | 519,467 | 515,079 | 510,691 | 506,303 | 501,915 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $3,248 | $3,222 | $3,196 | $3,170 | $3,144 | $3,119 | $3,080 | $3,054 | $3,028 | $3,002 | $2,976 | $2,951 | $37,190 |
| | b. Debt Component Grossed Up For Taxes (C) | | 933 | 925 | 918 | 910 | 903 | 896 | 850 | 843 | 836 | 829 | 822 | 814 | 10,479 |
| 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) | | 8,569 | 8,535 | 8,502 | 8,468 | 8,435 | 8,403 | 8,318 | 8,285 | 8,252 | 8,219 | 8,186 | 8,153 | 100,325 |
| | a. Recoverable Costs Allocated to Energy | | 8,569 | 8,535 | 8,502 | 8,468 | 8,435 | 8,403 | 8,318 | 8,285 | 8,252 | 8,219 | 8,186 | 8,153 | 100,325 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 8,569 | 8,535 | 8,502 | 8,468 | 8,435 | 8,403 | 8,318 | 8,285 | 8,252 | 8,219 | 8,186 | 8,153 | 100,325 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $8,569 | $8,535 | $8,502 | $8,468 | $8,435 | $8,403 | $8,318 | $8,285 | $8,252 | $8,219 | $8,186 | $8,153 | $100,325 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | (569,574) | (572,610) | (575,646) | (578,682) | (581,718) | (584,754) | (587,790) | (590,826) | (593,862) | (596,898) | (599,934) | (602,970) | (606,006) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $415,220 | 412,184 | 409,148 | 406,112 | 403,076 | 400,040 | 397,004 | 393,968 | 390,932 | 387,896 | 384,860 | 381,824 | 378,788 | |
| 6. | Average Net Investment | | 413,702 | 410,666 | 407,630 | 404,594 | 401,558 | 398,522 | 395,486 | 392,450 | 389,414 | 386,378 | 383,342 | 380,306 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $2,442 | $2,424 | $2,407 | $2,389 | $2,371 | $2,353 | $2,325 | $2,307 | $2,289 | $2,271 | $2,254 | $2,236 | $28,068 |
| | b. Debt Component Grossed Up For Taxes (C) | | 701 | 696 | 691 | 686 | 681 | 676 | 642 | 637 | 632 | 627 | 622 | 617 | 7,908 |
| 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) | | 6,179 | 6,156 | 6,134 | 6,111 | 6,088 | 6,065 | 6,003 | 5,980 | 5,957 | 5,934 | 5,912 | 5,889 | 72,408 |
| | a. Recoverable Costs Allocated to Energy | | 6,179 | 6,156 | 6,134 | 6,111 | 6,088 | 6,065 | 6,003 | 5,980 | 5,957 | 5,934 | 5,912 | 5,889 | 72,408 |
| | b. Recoverable Costs 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) | | 6,179 | 6,156 | 6,134 | 6,111 | 6,088 | 6,065 | 6,003 | 5,980 | 5,957 | 5,934 | 5,912 | 5,889 | 72,408 |
| 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) | | $6,179 | $6,156 | $6,134 | $6,111 | $6,088 | $6,065 | $6,003 | $5,980 | $5,957 | $5,934 | $5,912 | $5,889 | $72,408 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | (41,395) | (41,687) | (41,979) | (42,271) | (42,563) | (42,855) | (43,147) | (43,439) | (43,731) | (44,023) | (44,315) | (44,607) | (44,899) | |
| 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) | $79,342 | 79,050 | 78,758 | 78,466 | 78,174 | 77,882 | 77,590 | 77,298 | 77,006 | 76,714 | 76,422 | 76,130 | 75,838 | |
| 6. | Average Net Investment | | 79,196 | 78,904 | 78,612 | 78,320 | 78,028 | 77,736 | 77,444 | 77,152 | 76,860 | 76,568 | 76,276 | 75,984 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 468 | $466 | $464 | $462 | $461 | $459 | $455 | $454 | $452 | $450 | $448 | $447 | $5,486 |
| | b. Debt Component Grossed Up For Taxes (C) | | 134 | 134 | 133 | 133 | 132 | 132 | 126 | 125 | 125 | 124 | 124 | 123 | 1,545 |
| 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) | | 894 | 892 | 889 | 887 | 885 | 883 | 873 | 871 | 869 | 866 | 864 | 862 | 10,535 |
| | a. Recoverable Costs Allocated to Energy | | 894 | 892 | 889 | 887 | 885 | 883 | 873 | 871 | 869 | 866 | 864 | 862 | 10,535 |
| | b. Recoverable Costs 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) | | 894 | 892 | 889 | 887 | 885 | 883 | 873 | 871 | 869 | 866 | 864 | 862 | 10,535 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $894 | $892 | $889 | $887 | $885 | $883 | $873 | $871 | $869 | $866 | $864 | $862 | $10,535 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



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ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 8,
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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | | $18,518 | $4,309 | $4,218 | $734 | $0 | $0 | $0 | $30,000 | $0 | $0 | $0 | $0 | $57,779 |
| | b. Clearings to Plant | | 18,518 | 4,309 | 4,218 | 734 | 0 | 0 | 0 | 30,000 | 0 | 1,414,244 | 0 | 0 | 1,472,023 |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other - AFUDC (excl from CWIP) | | 86,773 | 55,920 | 46,371 | 41,112 | 34,814 | 20,861 | 40,007 | 61,958 | 16,277 | 3,226 | 0 | 0 | 407,319 |
| 2. | Plant-in-Service/Depreciation Base (A) | $93,268,465 | $93,286,983 | $93,291,292 | $93,295,511 | $93,296,244 | $93,296,244 | $93,296,244 | $93,296,244 | $93,326,244 | $93,326,244 | $94,740,488 | $94,740,488 | $94,740,488 | |
| 3. | Less: Accumulated Depreciation | (45,726,366) | (45,982,854) | (46,239,393) | (46,495,944) | (46,752,507) | (47,009,072) | (47,265,637) | (47,522,202) | (47,778,767) | (48,035,414) | (48,292,061) | (48,552,597) | (48,813,133) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 734 | 734 | 734 | 734 | 734 | 734 | 733 | 733 | 733 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $47,542,099 | 47,304,130 | 47,051,900 | 46,799,567 | 46,544,471 | 46,287,906 | 46,031,341 | 45,774,776 | 45,548,211 | 45,291,564 | 46,449,161 | 46,188,625 | 45,928,089 | |
| 6. | Average Net Investment | | 47,423,115 | 47,178,015 | 46,925,733 | 46,672,019 | 46,416,189 | 46,159,624 | 45,903,059 | 45,661,494 | 45,419,888 | 45,870,362 | 46,318,893 | 46,058,357 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $279,970 | $278,523 | $277,034 | $275,536 | $274,026 | $272,511 | $269,849 | $268,429 | $267,008 | $269,657 | $272,293 | $270,762 | $3,275,598 |
| | b. Debt Component Grossed Up For Taxes (C) | | 80,394 | 79,979 | 79,551 | 79,121 | 78,687 | 78,252 | 74,485 | 74,093 | 73,701 | 74,432 | 75,160 | 74,737 | 922,592 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $256,488 | $256,539 | $256,551 | $256,563 | $256,565 | $256,565 | $256,565 | $256,565 | $256,647 | $256,647 | $260,536 | $260,536 | $3,086,767 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 616,852 | 615,041 | 613,136 | 611,220 | 609,278 | 607,328 | 600,899 | 599,087 | 597,356 | 600,736 | 607,989 | 606,035 | 7,284,957 |
| | a. Recoverable Costs Allocated to Energy | | 616,852 | 615,041 | 613,136 | 611,220 | 609,278 | 607,328 | 600,899 | 599,087 | 597,356 | 600,736 | 607,989 | 606,035 | 7,284,957 |
| | b. Recoverable Costs 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) | | 616,852 | 615,041 | 613,136 | 611,220 | 609,278 | 607,328 | 600,899 | 599,087 | 597,356 | 600,736 | 607,989 | 606,035 | 7,284,957 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $616,852 | $615,041 | $613,136 | $611,220 | $609,278 | $607,328 | $600,899 | $599,087 | $597,356 | $600,736 | $607,989 | $606,035 | $7,284,957 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% x 1/12 (Jul-Dec).
(D) Applicable depreciation rates are 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



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ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimate July | Estimate August | Estimate September | Estimate October | Estimate November | Estimate December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $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 | (7,161,061) | (7,206,335) | (7,251,609) | (7,296,883) | (7,342,157) | (7,387,431) | (7,432,705) | (7,477,979) | (7,523,253) | (7,568,527) | (7,613,801) | (7,659,075) | (7,704,349) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $14,578,676 | 14,533,402 | 14,488,128 | 14,442,854 | 14,397,580 | 14,352,306 | 14,307,032 | 14,261,758 | 14,216,484 | 14,171,210 | 14,125,936 | 14,080,662 | 14,035,388 | |
| 6. | Average Net Investment | | 14,556,039 | 14,510,765 | 14,465,491 | 14,420,217 | 14,374,943 | 14,329,669 | 14,284,395 | 14,239,121 | 14,193,847 | 14,148,573 | 14,103,299 | 14,058,025 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $85,934 | $85,667 | $85,399 | $85,132 | $84,865 | $84,598 | $83,973 | $83,707 | $83,441 | $83,175 | $82,909 | $82,642 | $1,011,442 |
| | b. Debt Component Grossed Up For Taxes (C) | | 24,676 | 24,599 | 24,523 | 24,446 | 24,369 | 24,292 | 23,179 | 23,105 | 23,032 | 22,958 | 22,885 | 22,811 | 284,875 |
| 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) | | 155,884 | 155,540 | 155,196 | 154,852 | 154,508 | 154,164 | 152,426 | 152,086 | 151,747 | 151,407 | 151,068 | 150,727 | 1,839,605 |
| | a. Recoverable Costs Allocated to Energy | | 155,884 | 155,540 | 155,196 | 154,852 | 154,508 | 154,164 | 152,426 | 152,086 | 151,747 | 151,407 | 151,068 | 150,727 | 1,839,605 |
| | b. Recoverable Costs 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) | | 155,884 | 155,540 | 155,196 | 154,852 | 154,508 | 154,164 | 152,426 | 152,086 | 151,747 | 151,407 | 151,068 | 150,727 | 1,839,605 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $155,884 | $155,540 | $155,196 | $154,852 | $154,508 | $154,164 | $152,426 | $152,086 | $151,747 | $151,407 | $151,068 | $150,727 | $1,839,605 |

**Notes:**

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,699,919)and 311.45 ($39,818)
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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



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ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | 2,238,603 | 2,228,419 | 2,218,235 | 2,208,051 | 2,197,867 | 2,187,683 | 2,177,499 | 2,167,315 | 2,157,131 | 2,146,947 | 2,136,763 | 2,126,579 | 2,116,395 | |
| 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) | $5,429,455 | 5,419,271 | 5,409,087 | 5,398,903 | 5,388,719 | 5,378,535 | 5,368,351 | 5,358,167 | 5,347,983 | 5,337,799 | 5,327,615 | 5,317,431 | 5,307,247 | |
| 6. | Average Net Investment | | 5,424,363 | 5,414,179 | 5,403,995 | 5,393,811 | 5,383,627 | 5,373,443 | 5,363,259 | 5,353,075 | 5,342,891 | 5,332,707 | 5,322,523 | 5,312,339 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $32,024 | $31,964 | $31,903 | $31,843 | $31,783 | $31,723 | $31,529 | $31,469 | $31,409 | $31,349 | $31,289 | $31,229 | $379,514 |
| | b. Debt Component Grossed Up For Taxes (C) | | 9,196 | 9,178 | 9,161 | 9,144 | 9,127 | 9,109 | 8,703 | 8,686 | 8,670 | 8,653 | 8,637 | 8,620 | 106,884 |
| 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) | | 51,404 | 51,326 | 51,248 | 51,171 | 51,094 | 51,016 | 50,416 | 50,339 | 50,263 | 50,186 | 50,110 | 50,033 | 608,606 |
| | a. Recoverable Costs Allocated to Energy | | 51,404 | 51,326 | 51,248 | 51,171 | 51,094 | 51,016 | 50,416 | 50,339 | 50,263 | 50,186 | 50,110 | 50,033 | 608,606 |
| | b. Recoverable Costs 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) | | 51,404 | 51,326 | 51,248 | 51,171 | 51,094 | 51,016 | 50,416 | 50,339 | 50,263 | 50,186 | 50,110 | 50,033 | 608,606 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $51,404 | $51,326 | $51,248 | $51,171 | $51,094 | $51,016 | $50,416 | $50,339 | $50,263 | $50,186 | $50,110 | $50,033 | $608,606 |

**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 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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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ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | | $8,148 | $67,250 | $38,405 | $97,254 | $70,112 | $207,934 | $330,506 | $1,060,706 | $455,686 | $601,171 | $271,826 | $1,528,574 | $4,737,571 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,956,528 | 1,528,574 | 5,485,102 |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $15,439,547 | $19,396,076 | $20,924,650 | |
| 3. | Less: Accumulated Depreciation | (3,050,638) | (3,097,116) | (3,143,594) | (3,190,072) | (3,236,550) | (3,283,028) | (3,329,506) | (3,375,984) | (3,422,462) | (3,468,940) | (3,515,418) | (3,561,896) | (3,621,563) | |
| 4. | CWIP - Non-Interest Bearing | 747,531 | 755,679 | 822,929 | 861,334 | 958,587 | 1,028,699 | 1,236,634 | 1,567,140 | 2,627,846 | 3,083,532 | 3,684,703 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $13,136,441 | 13,098,110 | 13,118,882 | 13,110,809 | 13,161,585 | 13,185,218 | 13,346,675 | 13,630,703 | 14,644,931 | 15,054,139 | 15,608,832 | 15,834,180 | 17,303,087 | |
| 6. | Average Net Investment | | 13,117,275 | 13,108,496 | 13,114,845 | 13,136,197 | 13,173,402 | 13,265,947 | 13,488,689 | 14,137,817 | 14,849,535 | 15,331,485 | 15,721,506 | 16,568,633 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $77,440 | $77,388 | $77,426 | $77,552 | $77,771 | $78,318 | $79,296 | $83,112 | $87,295 | $90,129 | $92,421 | $97,401 | $995,549 |
| | b. Debt Component Grossed Up For Taxes (C) | | 22,237 | 22,222 | 22,233 | 22,269 | 22,332 | 22,489 | 21,888 | 22,941 | 24,096 | 24,878 | 25,511 | 26,885 | 279,981 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $46,478 | $46,478 | $46,478 | $46,478 | $46,478 | $46,478 | $46,478 | $46,478 | $46,478 | $46,478 | $46,478 | $59,667 | $570,925 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 146,155 | 146,088 | 146,137 | 146,299 | 146,581 | 147,285 | 147,662 | 152,531 | 157,869 | 161,485 | 164,410 | 183,953 | 1,846,455 |
| | a. Recoverable Costs Allocated to Energy | | 146,155 | 146,088 | 146,137 | 146,299 | 146,581 | 147,285 | 147,662 | 152,531 | 157,869 | 161,485 | 164,410 | 183,953 | 1,846,455 |
| | b. Recoverable Costs 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) | | 146,155 | 146,088 | 146,137 | 146,299 | 146,581 | 147,285 | 147,662 | 152,531 | 157,869 | 161,485 | 164,410 | 183,953 | 1,846,455 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $146,155 | $146,088 | $146,137 | $146,299 | $146,581 | $147,285 | $147,662 | $152,531 | $157,869 | $161,485 | $164,410 | $183,953 | $1,846,455 |

**Notes:**

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($6,998,365), 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 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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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ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | (577,146) | (581,570) | (585,994) | (590,418) | (594,842) | (599,266) | (603,690) | (608,114) | (612,538) | (616,962) | (621,386) | (625,810) | (630,234) | |
| 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) | $984,327 | 979,903 | 975,479 | 971,055 | 966,631 | 962,207 | 957,783 | 953,359 | 948,935 | 944,511 | 940,087 | 935,663 | 931,239 | |
| 6. | Average Net Investment | | 982,115 | 977,691 | 973,267 | 968,843 | 964,419 | 959,995 | 955,571 | 951,147 | 946,723 | 942,299 | 937,875 | 933,451 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $5,798 | $5,772 | $5,746 | $5,720 | $5,694 | $5,667 | $5,617 | $5,591 | $5,565 | $5,539 | $5,513 | $5,487 | $67,709 |
| | b. Debt Component Grossed Up For Taxes (C) | | 1,665 | 1,657 | 1,650 | 1,642 | 1,635 | 1,627 | 1,551 | 1,543 | 1,536 | 1,529 | 1,522 | 1,515 | 19,072 |
| 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) | | 11,887 | 11,853 | 11,820 | 11,786 | 11,753 | 11,718 | 11,592 | 11,558 | 11,525 | 11,492 | 11,459 | 11,426 | 139,869 |
| | a. Recoverable Costs Allocated to Energy | | 11,887 | 11,853 | 11,820 | 11,786 | 11,753 | 11,718 | 11,592 | 11,558 | 11,525 | 11,492 | 11,459 | 11,426 | 139,869 |
| | b. Recoverable Costs 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) | | 11,887 | 11,853 | 11,820 | 11,786 | 11,753 | 11,718 | 11,592 | 11,558 | 11,525 | 11,492 | 11,459 | 11,426 | 139,869 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $11,887 | $11,853 | $11,820 | $11,786 | $11,753 | $11,718 | $11,592 | $11,558 | $11,525 | $11,492 | $11,459 | $11,426 | $139,869 |

**Notes:**
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 2015 ACTUAL/ESTIMATED TRUE-UP
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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | (679,142) | (685,539) | (691,936) | (698,333) | (704,730) | (711,127) | (717,524) | (723,921) | (730,318) | (736,715) | (743,112) | (749,509) | (755,906) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,879,588 | 1,873,191 | 1,866,794 | 1,860,397 | 1,854,000 | 1,847,603 | 1,841,206 | 1,834,809 | 1,828,412 | 1,822,015 | 1,815,618 | 1,809,221 | 1,802,824 | |
| 6. | Average Net Investment | | 1,876,390 | 1,869,993 | 1,863,596 | 1,857,199 | 1,850,802 | 1,844,405 | 1,838,008 | 1,831,611 | 1,825,214 | 1,818,817 | 1,812,420 | 1,806,023 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $11,078 | $11,040 | $11,002 | $10,964 | $10,927 | $10,889 | $10,805 | $10,767 | $10,730 | $10,692 | $10,655 | $10,617 | $130,166 |
| | b. Debt Component Grossed Up For Taxes (C) | | 3,181 | 3,170 | 3,159 | 3,148 | 3,138 | 3,127 | 2,982 | 2,972 | 2,962 | 2,951 | 2,941 | 2,931 | 36,662 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $6,397 | $6,397 | $6,397 | $6,397 | $6,397 | $6,397 | $6,397 | $6,397 | $6,397 | $6,397 | $6,397 | $6,397 | $76,764 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 20,656 | 20,607 | 20,558 | 20,509 | 20,462 | 20,413 | 20,184 | 20,136 | 20,089 | 20,040 | 19,993 | 19,945 | 243,592 |
| | a. Recoverable Costs Allocated to Energy | | 20,656 | 20,607 | 20,558 | 20,509 | 20,462 | 20,413 | 20,184 | 20,136 | 20,089 | 20,040 | 19,993 | 19,945 | 243,592 |
| | b. Recoverable Costs 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) | | 20,656 | 20,607 | 20,558 | 20,509 | 20,462 | 20,413 | 20,184 | 20,136 | 20,089 | 20,040 | 19,993 | 19,945 | 243,592 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $20,656 | $20,607 | $20,558 | $20,509 | $20,462 | $20,413 | $20,184 | $20,136 | $20,089 | $20,040 | $19,993 | $19,945 | $243,592 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 8,
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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | (467,737) | (473,234) | (478,731) | (484,228) | (489,725) | (495,222) | (500,719) | (506,216) | (511,713) | (517,210) | (522,707) | (528,204) | (533,701) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,181,384 | 1,175,887 | 1,170,390 | 1,164,893 | 1,159,396 | 1,153,899 | 1,148,402 | 1,142,905 | 1,137,408 | 1,131,911 | 1,126,414 | 1,120,917 | 1,115,420 | |
| 6. | Average Net Investment | | 1,178,636 | 1,173,139 | 1,167,642 | 1,162,145 | 1,156,648 | 1,151,151 | 1,145,654 | 1,140,157 | 1,134,660 | 1,129,163 | 1,123,666 | 1,118,169 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $6,958 | $6,926 | $6,893 | $6,861 | $6,828 | $6,796 | $6,735 | $6,703 | $6,670 | $6,638 | $6,606 | $6,573 | $81,187 |
| | b. Debt Component Grossed Up For Taxes (C) | | 1,998 | 1,989 | 1,979 | 1,970 | 1,961 | 1,951 | 1,859 | 1,850 | 1,841 | 1,832 | 1,823 | 1,814 | 22,867 |
| 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) | | 14,453 | 14,412 | 14,369 | 14,328 | 14,286 | 14,244 | 14,091 | 14,050 | 14,008 | 13,967 | 13,926 | 13,884 | 170,018 |
| | a. Recoverable Costs Allocated to Energy | | 14,453 | 14,412 | 14,369 | 14,328 | 14,286 | 14,244 | 14,091 | 14,050 | 14,008 | 13,967 | 13,926 | 13,884 | 170,018 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 14,453 | 14,412 | 14,369 | 14,328 | 14,286 | 14,244 | 14,091 | 14,050 | 14,008 | 13,967 | 13,926 | 13,884 | 170,018 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $14,453 | $14,412 | $14,369 | $14,328 | $14,286 | $14,244 | $14,091 | $14,050 | $14,008 | $13,967 | $13,926 | $13,884 | $170,018 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | (418,748) | (423,625) | (428,502) | (433,379) | (438,256) | (443,133) | (448,010) | (452,887) | (457,764) | (462,641) | (467,518) | (472,395) | (477,272) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,163,139 | 1,158,262 | 1,153,385 | 1,148,508 | 1,143,631 | 1,138,754 | 1,133,877 | 1,129,000 | 1,124,123 | 1,119,246 | 1,114,369 | 1,109,492 | 1,104,615 | |
| 6. | Average Net Investment | | 1,160,701 | 1,155,824 | 1,150,947 | 1,146,070 | 1,141,193 | 1,136,316 | 1,131,439 | 1,126,562 | 1,121,685 | 1,116,808 | 1,111,931 | 1,107,054 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $6,852 | $6,824 | $6,795 | $6,766 | $6,737 | $6,708 | $6,651 | $6,623 | $6,594 | $6,565 | $6,537 | $6,508 | $80,160 |
| | b. Debt Component Grossed Up For Taxes (C) | | 1,968 | 1,959 | 1,951 | 1,943 | 1,935 | 1,926 | 1,836 | 1,828 | 1,820 | 1,812 | 1,804 | 1,796 | 22,578 |
| 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) | | 13,697 | 13,660 | 13,623 | 13,586 | 13,549 | 13,511 | 13,364 | 13,328 | 13,291 | 13,254 | 13,218 | 13,181 | 161,262 |
| | a. Recoverable Costs Allocated to Energy | | 13,697 | 13,660 | 13,623 | 13,586 | 13,549 | 13,511 | 13,364 | 13,328 | 13,291 | 13,254 | 13,218 | 13,181 | 161,262 |
| | b. Recoverable Costs 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) | | 13,697 | 13,660 | 13,623 | 13,586 | 13,549 | 13,511 | 13,364 | 13,328 | 13,291 | 13,254 | 13,218 | 13,181 | 161,262 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $13,697 | $13,660 | $13,623 | $13,586 | $13,549 | $13,511 | $13,364 | $13,328 | $13,291 | $13,254 | $13,218 | $13,181 | $161,262 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | (545,894) | (553,847) | (561,800) | (569,753) | (577,706) | (585,659) | (593,612) | (601,565) | (609,518) | (617,471) | (625,424) | (633,377) | (641,330) | |
| 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) | $2,160,613 | 2,152,660 | 2,144,707 | 2,136,754 | 2,128,801 | 2,120,848 | 2,112,895 | 2,104,942 | 2,096,989 | 2,089,036 | 2,081,083 | 2,073,130 | 2,065,177 | |
| 6. | Average Net Investment | | 2,156,637 | 2,148,684 | 2,140,731 | 2,132,778 | 2,124,825 | 2,116,872 | 2,108,919 | 2,100,966 | 2,093,013 | 2,085,060 | 2,077,107 | 2,069,154 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $12,732 | $12,685 | $12,638 | $12,591 | $12,544 | $12,497 | $12,398 | $12,351 | $12,304 | $12,257 | $12,211 | $12,164 | $149,372 |
| | b. Debt Component Grossed Up For Taxes (C) | | 3,656 | 3,643 | 3,629 | 3,616 | 3,602 | 3,589 | 3,422 | 3,409 | 3,396 | 3,383 | 3,370 | 3,358 | 42,073 |
| 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) | | 24,341 | 24,281 | 24,220 | 24,160 | 24,099 | 24,039 | 23,773 | 23,713 | 23,653 | 23,593 | 23,534 | 23,475 | 286,881 |
| | a. Recoverable Costs Allocated to Energy | | 24,341 | 24,281 | 24,220 | 24,160 | 24,099 | 24,039 | 23,773 | 23,713 | 23,653 | 23,593 | 23,534 | 23,475 | 286,881 |
| | b. Recoverable Costs 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) | | 24,341 | 24,281 | 24,220 | 24,160 | 24,099 | 24,039 | 23,773 | 23,713 | 23,653 | 23,593 | 23,534 | 23,475 | 286,881 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $24,341 | $24,281 | $24,220 | $24,160 | $24,099 | $24,039 | $23,773 | $23,713 | $23,653 | $23,593 | $23,534 | $23,475 | $286,881 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | $322 | $0 | $0 | $0 | $0 | $0 | $0 | $322 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 322 | 0 | 0 | 0 | 0 | 0 | 0 | 322 |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | |
| 3. | Less: Accumulated Depreciation | (17,719,658) | (18,028,824) | (18,337,990) | (18,647,156) | (18,956,322) | (19,265,488) | (19,574,654) | (19,883,821) | (20,192,988) | (20,502,155) | (20,811,322) | (21,120,489) | (21,429,656) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $67,999,444 | 67,690,278 | 67,381,112 | 67,071,946 | 66,762,780 | 66,453,614 | 66,144,769 | 65,835,602 | 65,526,435 | 65,217,268 | 64,908,101 | 64,598,934 | 64,289,767 | |
| 6. | Average Net Investment | | 67,844,861 | 67,535,695 | 67,226,529 | 66,917,363 | 66,608,197 | 66,299,192 | 65,990,186 | 65,681,019 | 65,371,852 | 65,062,685 | 64,753,518 | 64,444,351 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $400,533 | $398,708 | $396,883 | $395,058 | $393,233 | $391,408 | $387,934 | $386,117 | $384,299 | $382,482 | $380,664 | $378,847 | $4,676,166 |
| | b. Debt Component Grossed Up For Taxes (C) | | 115,014 | 114,490 | 113,966 | 113,442 | 112,918 | 112,394 | 107,080 | 106,578 | 106,077 | 105,575 | 105,073 | 104,572 | 1,317,179 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $309,166 | $309,166 | $309,166 | $309,166 | $309,166 | $309,166 | $309,167 | $309,167 | $309,167 | $309,167 | $309,167 | $309,167 | $3,709,998 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 824,713 | 822,364 | 820,015 | 817,666 | 815,317 | 812,968 | 804,181 | 801,862 | 799,543 | 797,224 | 794,904 | 792,586 | 9,703,343 |
| | a. Recoverable Costs Allocated to Energy | | 824,713 | 822,364 | 820,015 | 817,666 | 815,317 | 812,968 | 804,181 | 801,862 | 799,543 | 797,224 | 794,904 | 792,586 | 9,703,343 |
| | b. Recoverable Costs 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) | | 824,713 | 822,364 | 820,015 | 817,666 | 815,317 | 812,968 | 804,181 | 801,862 | 799,543 | 797,224 | 794,904 | 792,586 | 9,703,343 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $824,713 | $822,364 | $820,015 | $817,666 | $815,317 | $812,968 | $804,181 | $801,862 | $799,543 | $797,224 | $794,904 | $792,586 | $9,703,343 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 311.51 ($22,278,982), 312.51 ($48,529,993), 315.51 ($14,063,245), and 316.51 ($847,203).
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | | $489,244 | $9,719 | $3,840 | $3,289 | $752,190 | $101,256 | $240 | $0 | $10,000 | $0 | $0 | $0 | $1,369,777 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,369,777 | 0 | 0 | 1,369,777 |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $93,776,097 | $95,145,874 | $95,145,874 | $95,145,874 | |
| 3. | Less: Accumulated Depreciation | (19,774,484) | (20,077,654) | (20,380,824) | (20,683,994) | (20,987,164) | (21,290,334) | (21,593,504) | (21,896,674) | (22,199,844) | (22,503,014) | (22,806,184) | (23,113,920) | (23,421,656) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 489,244 | 498,964 | 502,803 | 506,092 | 1,258,282 | 1,359,537 | 1,359,777 | 1,359,777 | 1,369,777 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $74,001,613 | 74,187,687 | 73,894,236 | 73,594,906 | 73,295,025 | 73,744,044 | 73,542,130 | 73,239,200 | 72,936,030 | 72,642,860 | 72,339,690 | 72,031,954 | 71,724,218 | |
| 6. | Average Net Investment | | 74,094,650 | 74,040,962 | 73,744,571 | 73,444,965 | 73,519,534 | 73,643,087 | 73,390,665 | 73,087,615 | 72,789,445 | 72,491,275 | 72,185,822 | 71,878,086 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $437,430 | $437,113 | $435,363 | $433,595 | $434,035 | $434,764 | $431,439 | $429,658 | $427,905 | $426,152 | $424,356 | $422,547 | $5,174,357 |
| | b. Debt Component Grossed Up For Taxes (C) | | 125,609 | 125,518 | 125,015 | 124,508 | 124,634 | 124,843 | 119,089 | 118,597 | 118,113 | 117,629 | 117,134 | 116,634 | 1,457,323 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $303,170 | $303,170 | $303,170 | $303,170 | $303,170 | $303,170 | $303,170 | $303,170 | $303,170 | $303,170 | $307,736 | $307,736 | $3,647,172 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 866,209 | 865,801 | 863,548 | 861,273 | 861,839 | 862,777 | 853,698 | 851,425 | 849,188 | 846,951 | 849,226 | 846,917 | 10,278,852 |
| | a. Recoverable Costs Allocated to Energy | | 866,209 | 865,801 | 863,548 | 861,273 | 861,839 | 862,777 | 853,698 | 851,425 | 849,188 | 846,951 | 849,226 | 846,917 | 10,278,852 |
| | b. Recoverable Costs 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) | | 866,209 | 865,801 | 863,548 | 861,273 | 861,839 | 862,777 | 853,698 | 851,425 | 849,188 | 846,951 | 849,226 | 846,917 | 10,278,852 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $866,209 | $865,801 | $863,548 | $861,273 | $861,839 | $862,777 | $853,698 | $851,425 | $849,188 | $846,951 | $849,226 | $846,917 | $10,278,852 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($53,063,962), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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) | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | |
| 3. | Less: Accumulated Depreciation | (18,986,041) | (19,233,582) | (19,481,123) | (19,728,664) | (19,976,205) | (20,223,746) | (20,471,287) | (20,718,828) | (20,966,369) | (21,213,910) | (21,461,451) | (21,708,992) | (21,956,533) | |
| 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) | $61,383,846 | 61,136,305 | 60,888,764 | 60,641,223 | 60,393,682 | 60,146,141 | 59,898,600 | 59,651,059 | 59,403,518 | 59,155,977 | 58,908,436 | 58,660,895 | 58,413,354 | |
| 6. | Average Net Investment | | 61,260,075 | 61,012,534 | 60,764,993 | 60,517,452 | 60,269,911 | 60,022,370 | 59,774,829 | 59,527,288 | 59,279,747 | 59,032,206 | 58,784,665 | 58,537,124 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $361,659 | $360,198 | $358,736 | $357,275 | $355,813 | $354,352 | $351,396 | $349,941 | $348,486 | $347,031 | $345,575 | $344,120 | $4,234,582 |
| | b. Debt Component Grossed Up For Taxes (C) | | 103,851 | 103,431 | 103,012 | 102,592 | 102,173 | 101,753 | 96,995 | 96,593 | 96,191 | 95,790 | 95,388 | 94,986 | 1,192,755 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $247,541 | $247,541 | $247,541 | $247,541 | $247,541 | $247,541 | $247,541 | $247,541 | $247,541 | $247,541 | $247,541 | $247,541 | $2,970,492 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 713,051 | 711,170 | 709,289 | 707,408 | 705,527 | 703,646 | 695,932 | 694,075 | 692,218 | 690,362 | 688,504 | 686,647 | 8,397,829 |
| | a. Recoverable Costs Allocated to Energy | | 713,051 | 711,170 | 709,289 | 707,408 | 705,527 | 703,646 | 695,932 | 694,075 | 692,218 | 690,362 | 688,504 | 686,647 | 8,397,829 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 713,051 | 711,170 | 709,289 | 707,408 | 705,527 | 703,646 | 695,932 | 694,075 | 692,218 | 690,362 | 688,504 | 686,647 | 8,397,829 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $713,051 | $711,170 | $709,289 | $707,408 | $705,527 | $703,646 | $695,932 | $694,075 | $692,218 | $690,362 | $688,504 | $686,647 | $8,397,829 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 311.53 ($21,689,422), 312.53 ($44,164,828), 315.53 ($13,690,954), and 316.53 ($824,684).
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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 (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | | $4,790 | $3,799 | $10,085 | $9,029 | $4,856 | $3,781 | $420,837 | $0 | $0 | $0 | $0 | $0 | $457,178 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 420,603 | 0 | 0 | 0 | 0 | 555,166 | 975,769 |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $62,853,033 | $63,273,636 | $63,273,636 | $63,273,636 | $63,273,636 | $63,273,636 | $63,828,803 | |
| 3. | Less: Accumulated Depreciation | (15,866,135) | (16,046,103) | (16,226,071) | (16,406,039) | (16,586,007) | (16,765,975) | (16,945,943) | (17,125,911) | (17,307,211) | (17,488,511) | (17,669,811) | (17,851,111) | (18,032,411) | |
| 4. | CWIP - Non-Interest Bearing | 518,591 | 523,381 | 527,180 | 537,265 | 546,295 | 551,151 | 554,932 | 555,166 | 555,166 | 555,166 | 555,166 | 555,166 | (0) | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $47,505,489 | 47,330,312 | 47,154,142 | 46,984,260 | 46,813,321 | 46,638,209 | 46,462,022 | 46,702,891 | 46,521,591 | 46,340,291 | 46,158,991 | 45,977,691 | 45,796,391 | |
| 6. | Average Net Investment | | 47,417,900 | 47,242,227 | 47,069,201 | 46,898,790 | 46,725,765 | 46,550,116 | 46,582,457 | 46,612,241 | 46,430,941 | 46,249,641 | 46,068,341 | 45,887,041 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $279,939 | $278,902 | $277,881 | $276,875 | $275,853 | $274,816 | $273,843 | $274,018 | $272,952 | $271,886 | $270,820 | $269,755 | $3,297,540 |
| | b. Debt Component Grossed Up For Taxes (C) | | 80,385 | 80,087 | 79,794 | 79,505 | 79,212 | 78,914 | 75,588 | 75,636 | 75,342 | 75,048 | 74,754 | 74,459 | 928,724 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $179,968 | $179,968 | $179,968 | $179,968 | $179,968 | $179,968 | $179,968 | $181,300 | $181,300 | $181,300 | $181,300 | $181,300 | $2,166,276 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 540,292 | 538,957 | 537,643 | 536,348 | 535,033 | 533,698 | 529,399 | 530,954 | 529,594 | 528,234 | 526,874 | 525,514 | 6,392,540 |
| | a. Recoverable Costs Allocated to Energy | | 540,292 | 538,957 | 537,643 | 536,348 | 535,033 | 533,698 | 529,399 | 530,954 | 529,594 | 528,234 | 526,874 | 525,514 | 6,392,540 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 540,292 | 538,957 | 537,643 | 536,348 | 535,033 | 533,698 | 529,399 | 530,954 | 529,594 | 528,234 | 526,874 | 525,514 | 6,392,540 |
| 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) | | $540,292 | $538,957 | $537,643 | $536,348 | $535,033 | $533,698 | $529,399 | $530,954 | $529,594 | $528,234 | $526,874 | $525,514 | $6,392,540 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($35,086,425), 315.54 ($11,197,193), and 316.54 ($687,934).
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 2.4%, 3.8%. 3.9%, and 3.3%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11



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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | (2,753,538) | (2,804,847) | (2,856,156) | (2,907,465) | (2,958,774) | (3,010,083) | (3,061,392) | (3,112,701) | (3,164,010) | (3,215,319) | (3,266,628) | (3,317,937) | (3,369,246) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $21,583,169 | 21,531,860 | 21,480,551 | 21,429,242 | 21,377,933 | 21,326,624 | 21,275,315 | 21,224,006 | 21,172,697 | 21,121,388 | 21,070,079 | 21,018,770 | 20,967,461 | |
| 6. | Average Net Investment | | 21,557,515 | 21,506,206 | 21,454,897 | 21,403,588 | 21,352,279 | 21,300,970 | 21,249,661 | 21,198,352 | 21,147,043 | 21,095,734 | 21,044,425 | 20,993,116 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $127,268 | $126,965 | $126,663 | $126,360 | $126,057 | $125,754 | $124,920 | $124,618 | $124,316 | $124,015 | $123,713 | $123,412 | $1,504,061 |
| | b. Debt Component Grossed Up For Taxes (C) | | 36,545 | 36,458 | 36,371 | 36,284 | 36,197 | 36,110 | 34,481 | 34,398 | 34,315 | 34,231 | 34,148 | 34,065 | 423,603 |
| 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) | | 215,122 | 214,732 | 214,343 | 213,953 | 213,563 | 213,173 | 210,710 | 210,325 | 209,940 | 209,555 | 209,170 | 208,786 | 2,543,372 |
| | a. Recoverable Costs Allocated to Energy | | 215,122 | 214,732 | 214,343 | 213,953 | 213,563 | 213,173 | 210,710 | 210,325 | 209,940 | 209,555 | 209,170 | 208,786 | 2,543,372 |
| | b. Recoverable Costs 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) | | 215,122 | 214,732 | 214,343 | 213,953 | 213,563 | 213,173 | 210,710 | 210,325 | 209,940 | 209,555 | 209,170 | 208,786 | 2,543,372 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $215,122 | $214,732 | $214,343 | $213,953 | $213,563 | $213,173 | $210,710 | $210,325 | $209,940 | $209,555 | $209,170 | $208,786 | $2,543,372 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.45 ($22,880,499) and 312.44 ($1,456,209).
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 2.5% and 3.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11



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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | | $1,122 | $2,101 | $3,763 | $20,619 | $137,865 | $10,165 | $423 | $0 | $0 | $160,000 | $0 | $0 | $336,058 |
| | b. Clearings to Plant | | (647) | 1,102 | 2,006 | 16,099 | 318,824 | 10,165 | 423 | 0 | 0 | 0 | 0 | 160,000 | 507,972 |
| | 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) | $8,205,315 | $8,204,668 | $8,205,770 | $8,207,776 | $8,223,875 | $8,542,700 | $8,552,865 | $8,553,288 | $8,553,288 | $8,553,288 | $8,553,288 | $8,553,288 | $8,713,288 | |
| 3. | Less: Accumulated Depreciation | (374,961) | (395,736) | (416,511) | (437,290) | (458,073) | (478,896) | (500,430) | (521,988) | (543,546) | (565,104) | (586,662) | (608,220) | (629,778) | |
| 4. | CWIP - Non-Interest Bearing | 171,914 | 173,683 | 174,682 | 176,439 | 180,959 | 0 | 0 | 0 | 0 | 0 | 160,000 | 160,000 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $8,002,268 | 7,982,615 | 7,963,941 | 7,946,926 | 7,946,762 | 8,063,804 | 8,052,435 | 8,031,300 | 8,009,742 | 7,988,184 | 8,126,626 | 8,105,068 | 8,083,510 | |
| 6. | Average Net Investment | | 7,992,442 | 7,973,278 | 7,955,433 | 7,946,844 | 8,005,283 | 8,058,119 | 8,041,867 | 8,020,521 | 7,998,963 | 8,057,405 | 8,115,847 | 8,094,289 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $47,185 | $47,072 | $46,966 | $46,916 | $47,261 | $47,572 | $47,275 | $47,150 | $47,023 | $47,367 | $47,710 | $47,584 | $567,081 |
| | b. Debt Component Grossed Up For Taxes (C) | | 13,549 | 13,517 | 13,486 | 13,472 | 13,571 | 13,661 | 13,049 | 13,015 | 12,980 | 13,074 | 13,169 | 13,134 | 159,677 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $20,775 | $20,775 | $20,779 | $20,783 | $20,823 | $21,534 | $21,558 | $21,558 | $21,558 | $21,558 | $21,558 | $21,558 | $254,817 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 81,509 | 81,364 | 81,231 | 81,171 | 81,655 | 82,767 | 81,882 | 81,723 | 81,561 | 81,999 | 82,437 | 82,276 | 981,575 |
| | a. Recoverable Costs Allocated to Energy | | 81,509 | 81,364 | 81,231 | 81,171 | 81,655 | 82,767 | 81,882 | 81,723 | 81,561 | 81,999 | 82,437 | 82,276 | 981,575 |
| | b. Recoverable Costs 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) | | 81,509 | 81,364 | 81,231 | 81,171 | 81,655 | 82,767 | 81,882 | 81,723 | 81,561 | 81,999 | 82,437 | 82,276 | 981,575 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $81,509 | $81,364 | $81,231 | $81,171 | $81,655 | $82,767 | $81,882 | $81,723 | $81,561 | $81,999 | $82,437 | $82,276 | $981,575 |

**Notes:**

(A) Applicable depreciable base for Big Bend and Polk; accounts 315.43 ($40,000), 315.44 ($40,000), 312.44 ($3,426,581), 341.80($26,150), 315.40 ($1,226,949), 315.41($138,853), 315.42($138,853), 312.45 ($2,262,901), 312.46 ($1,242,315), 315.45 ($40,217) and 315.46 ($75,022), 311.40 ($13,216), and 345.81 ($42,232)

(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% x 1/12 (Jul-Dec).

(D) Applicable depreciation rate is 3.6%, 3.2%, 3.0%, 2.2%, 3.7%, 3.5%, 3.3%, 2.5%, 3.3%, 3.1%, 3.5%, 2.9% and 3.3%

(E) Line 9a x Line 10

(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 8,
PAGE 23 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | |
| | c. Auction Proceeds/Other | | 0 | 0 | 0 | 171 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 171 |
| 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 | (35,777) | (35,589) | (35,589) | (35,589) | (35,590) | (35,590) | (35,590) | (35,516) | (35,447) | (35,390) | (35,335) | (35,271) | (35,207) | |
| 3. | Total Working Capital Balance | ($35,777) | (35,589) | (35,589) | (35,589) | (35,590) | (35,590) | (35,590) | (35,516) | (35,447) | (35,390) | (35,335) | (35,271) | (35,207) | |
| 4. | Average Net Working Capital Balance | | ($35,683) | ($35,589) | ($35,589) | ($35,590) | ($35,590) | ($35,590) | ($35,553) | ($35,481) | ($35,418) | ($35,362) | ($35,303) | ($35,239) | |
| 5. | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (A) | | (211) | (210) | (210) | (210) | (210) | (210) | (209) | (209) | (208) | (208) | (208) | (207) | (2,510) |
| | b. Debt Component Grossed Up For Taxes (B) | | (60) | (60) | (60) | (60) | (60) | (60) | (58) | (58) | (57) | (57) | (57) | (57) | (704) |
| 6. | Total Return Component | | (271) | (270) | (270) | (270) | (270) | (270) | (267) | (267) | (265) | (265) | (265) | (264) | (3,214) |
| 7. | Expenses: | | | | | | | | | | | | | | |
| | a. Gains | | 0 | 0 | 0 | (171) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (171) |
| | b. Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. $SO_2$ Allowance Expense | | (144) | 30 | 58 | 41 | 70 | 95 | 2,556 | 2,538 | 2,550 | 2,582 | 2,521 | 2,472 | 15,369 |
| 8. | Net Expenses (D) | | (144) | 30 | 58 | (130) | 70 | 95 | 2,556 | 2,538 | 2,550 | 2,582 | 2,521 | 2,472 | 15,198 |
| 9. | Total System Recoverable Expenses (Lines 6 + 8) | | (415) | (240) | (212) | (400) | (200) | (175) | 2,289 | 2,271 | 2,285 | 2,317 | 2,256 | 2,208 | 11,984 |
| | a. Recoverable Costs Allocated to Energy | | (415) | (240) | (212) | (400) | (200) | (175) | 2,289 | 2,271 | 2,285 | 2,317 | 2,256 | 2,208 | 11,984 |
| | b. Recoverable Costs 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) | | (415) | (240) | (212) | (400) | (200) | (175) | 2,289 | 2,271 | 2,285 | 2,317 | 2,256 | 2,208 | 11,984 |
| 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) | | ($415) | ($240) | ($212) | ($400) | ($200) | ($175) | $2,289 | $2,271 | $2,285 | $2,317 | $2,256 | $2,208 | $11,984 |

**Notes:**
(A) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% 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.



DOCKET NO. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 8,
PAGE 24 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to December 2015**

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 | | $88,251 | $65,289 | $72,436 | $4,769 | $40,886 | $19,002 | $4,405 | $0 | $0 | $0 | $0 | $0 | $295,038 |
| | b. Clearings to Plant | | 88,251 | 65,289 | 72,436 | 4,769 | 40,886 | 19,002 | 4,405 | 0 | 0 | 0 | 0 | 0 | 295,038 |
| | 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) | $20,963,264 | 21,051,515 | 21,116,804 | 21,189,240 | 21,194,009 | 21,234,895 | 21,253,897 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,301.56 | |
| 3. | Less: Accumulated Depreciation | (50,274) | (100,935) | (151,809) | (202,841) | (254,048) | (305,267) | (356,585) | (407,949) | (459,323) | (510,697) | (562,071) | (613,445) | (664,819) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $20,912,990 | 20,950,580 | 20,964,995 | 20,986,399 | 20,939,961 | 20,929,628 | 20,897,312 | 20,850,353 | 20,798,979 | 20,747,605 | 20,696,231 | 20,644,857 | 20,593,483 | |
| 6. | Average Net Investment | | 20,931,785 | 20,957,787 | 20,975,697 | 20,963,180 | 20,934,794 | 20,913,470 | 20,873,832 | 20,824,666 | 20,773,292 | 20,721,918 | 20,670,544 | 20,619,170 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $123,574 | $123,728 | $123,834 | $123,760 | $123,592 | $123,466 | $122,710 | $122,421 | $122,119 | $121,817 | $121,515 | $121,213 | $1,473,749 |
| | b. Debt Component Grossed Up For Taxes (C) | | 35,485 | 35,529 | 35,559 | 35,538 | 35,490 | 35,454 | 33,871 | 33,791 | 33,708 | 33,625 | 33,541 | 33,458 | 415,049 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $50,661 | $50,874 | $51,032 | $51,207 | $51,219 | $51,318 | $51,364 | $51,374 | $51,374 | $51,374 | $51,374 | $51,374 | $614,545 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 209,720 | 210,131 | 210,425 | 210,505 | 210,301 | 210,238 | 207,945 | 207,586 | 207,201 | 206,816 | 206,430 | 206,045 | 2,503,343 |
| | a. Recoverable Costs Allocated to Energy | | 209,720 | 210,131 | 210,425 | 210,505 | 210,301 | 210,238 | 207,945 | 207,586 | 207,201 | 206,816 | 206,430 | 206,045 | 2,503,343 |
| | b. Recoverable Costs 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) | | 209,720 | 210,131 | 210,425 | 210,505 | 210,301 | 210,238 | 207,945 | 207,586 | 207,201 | 206,816 | 206,430 | 206,045 | 2,503,343 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $209,720 | $210,131 | $210,425 | $210,505 | $210,301 | $210,238 | $207,945 | $207,586 | $207,201 | $206,816 | $206,430 | $206,045 | $2,503,343 |

**Notes:**

(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 7.0844% x 1/12 (Jan-Jun) and Line 6 x 7.0544% 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 2.0343% x 1/12 (Jan-Jun) and Line 6 x 1.9472% x 1/12 (Jul-Dec).
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2015 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. ___ (PAR-2), DOCUMENT NO. 8,
PAGE 25 OF 25

**Tampa Electric Company** Form 42 - 9E
Environmental Cost Recovery Clause (ECRC) Page 1 of 2
Calculation of the Current Period Actual / Estimated Amount
**January 2015 to June 2015**

**Calculation of Revenue Requirement Rate of Return**
(In Dollars)

| | (1) Jurisdictional Rate Base **Actual May 2014** | (2) Ratio | (3) Cost Rate | (4) Weighted Cost Rate |
|---|---|---|---|---|
| | ($000) | % | % | % |
| Long Term Debt | $ 1,429,551 | 35.37% | 5.55% | 1.9630% |
| Short Term Debt | 25,222 | 0.62% | 0.61% | 0.0038% |
| Preferred Stock | 0 | 0.00% | 0.00% | 0.0000% |
| Customer Deposits | 107,785 | 2.67% | 2.25% | 0.0601% |
| Common Equity | 1,707,776 | 42.26% | 10.25% | 4.3317% |
| Deferred ITC - Weighted Cost | 8,027 | 0.20% | 8.05% | 0.0161% |
| Accumulated Deferred Income Taxes | 763,143 | 18.88% | 0.00% | 0.0000% |
| Zero Cost ITCs | | | | |
| Total | $ 4,041,504 | 100.00% | | 6.37% |

**ITC split between Debt and Equity:**

| | | | |
|---|---|---|---|
| Long Term Debt | $ 1,429,551 | Long Term Debt | 45.20% |
| Short Term Debt | 25,222 | Short Term Debt | 0.80% |
| Equity - Preferred | 0 | Equity - Preferred | 0.00% |
| Equity - Common | 1,707,776 | Equity - Common | 54.00% |
| Total | $ 3,162,549 | Total | 100.00% |

**Deferred ITC - Weighted Cost:**

| | |
|---|---|
| Debt = .0161% * 46.00% | 0.0074% |
| Equity = .0161% * 54.00% | 0.0087% |
| Weighted Cost | 0.0161% |

**Total Equity Cost Rate:**

| | |
|---|---|
| Preferred Stock | 0.0000% |
| Common Equity | 4.3317% |
| Deferred ITC - Weighted Cost | 0.0087% |
| | 4.3404% |
| Times Tax Multiplier | 1.632200 |
| Total Equity Component | **7.0844%** |

**Total Debt Cost Rate:**

| | |
|---|---|
| Long Term Debt | 1.9630% |
| Short Term Debt | 0.0038% |
| Customer Deposits | 0.0601% |
| Deferred ITC - Weighted Cost | 0.0074% |
| Total Debt Component | **2.0343%** |
| | **9.1187%** |

**Notes:**

* Adjusted to 54% equity, per Base Rates Settlement Agreement Dated September 6, 2013.
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (2) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (3) - Column (2) / Total Column (2)
Column (4) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (5) - Column (3) x Column (4)

**Tampa Electric Company** Form 42 - 9E
Environmental Cost Recovery Clause (ECRC) Page 2 of 2
Calculation of the Current Period Actual / Estimated Amount
**July 2015 to December 2015**

**Calculation of Revenue Requirement Rate of Return**
(In Dollars)

| | (1) Jurisdictional Rate Base **Actual May 2015** | (2) Ratio | (3) Cost Rate | (4) Weighted Cost Rate |
|---|---|---|---|---|
| | ($000) | % | % | % |
| Long Term Debt | $ 1,500,445 | 35.24% | 5.33% | 1.8783% |
| Short Term Debt | 25,918 | 0.61% | 0.71% | 0.0043% |
| Preferred Stock | 0 | 0.00% | 0.00% | 0.0000% |
| Customer Deposits | 108,557 | 2.55% | 2.27% | 0.0579% |
| Common Equity | 1,791,818 | 42.09% | 10.25% | 4.3142% |
| Deferred ITC - Weighted Cost | 7,573 | 0.18% | 8.05% | 0.0145% |
| Accumulated Deferred Income Taxes | 823,006 | 19.33% | 0.00% | 0.0000% |
| Zero Cost ITCs | | | | |
| Total | $ 4,257,317 | 100.00% | | 6.27% |

**ITC split between Debt and Equity:**

| | | | |
|---|---|---|---|
| Long Term Debt | $ 1,500,445 | Long Term Debt | 45.22% |
| Short Term Debt | 25,918 | Short Term Debt | 0.78% |
| Equity - Preferred | 0 | Equity - Preferred | 0.00% |
| Equity - Common | 1,791,818 | Equity - Common | 54.00% |
| Total | $ 3,318,181 | Total | 100.00% |

**Deferred ITC - Weighted Cost:**

| | |
|---|---|
| Debt = .0161% * 46.00% | 0.0067% |
| Equity = .0161% * 54.00% | 0.0078% |
| Weighted Cost | 0.0145% |

**Total Equity Cost Rate:**

| | |
|---|---|
| Preferred Stock | 0.0000% |
| Common Equity | 4.3142% |
| Deferred ITC - Weighted Cost | 0.0078% |
| | 4.3220% |
| Times Tax Multiplier | 1.632200 |
| Total Equity Component | 7.0544% |

**Total Debt Cost Rate:**

| | |
|---|---|
| Long Term Debt | 1.8783% |
| Short Term Debt | 0.0043% |
| Customer Deposits | 0.0579% |
| Deferred ITC - Weighted Cost | 0.0067% |
| Total Debt Component | 1.9472% |
| | 9.0016% |

**Notes:**

* Adjusted to 54% equity, per Base Rates Settlement Agreement Dated September 6, 2013.
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (2) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (3) - Column (2) / Total Column (2)
Column (4) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (5) - Column (3) x Column (4)

# INDEX

## ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

## JANUARY 2016 THROUGH DECEMBER 2016


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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 23
PARTY: TAMPA ELECTRIC COMPANY (TECO) – (DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-3

Form 42 - 1P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
**January 2016 to December 2016**

| 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) | $26,055,047 | $1,019,500 | $27,074,547 |
| b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9) | 54,077,003 | 104,026 | 54,181,029 |
| c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + | 80,132,050 | 1,123,526 | 81,255,576 |
| 2. True-up for Estimated Over/(Under) Recovery for the current period January 2015 to December 2015 (Form 42-2E, Line 5 + 6 + 10) | 4,503,083 | 32,190 | 4,535,273 |
| 3. Final True-up for the period January 2014 to December 2014 (Form 42-1A, Line 3) | (3,863,461) | (52,175) | (3,915,636) |
| 4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2016 to December 2016 (Line 1 - Line 2- Line 3) | 79,492,428 | 1,143,511 | 80,635,939 |
| 5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier) | $79,549,663 | $1,144,334 | $80,693,997 |

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

Form 42 - 2P

**O&M Activities**
(in Dollars)

| Line | | Projected January | Projected February | Projected March | Projected April | Projected May | Projected June | Projected July | Projected August | Projected September | Projected October | Projected November | Projected December | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Description of O&M Activities | | | | | | | | | | | | | | | |
| | a. Big Bend Unit 3 Flue Gas Desulfurization Integration | $480,030 | $501,150 | $501,150 | $480,030 | $480,030 | $480,030 | $480,030 | $480,030 | $480,030 | $480,030 | $501,150 | $501,150 | $5,844,840 | | $5,844,840 |
| | 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 | 728 | 743 | 757 | 739 | 732 | 732 | 721 | 728 | 730 | 728 | 720 | 747 | 8,805 | | 8,805 |
| | d. Big Bend Units 1 & 2 FGD | 793,367 | 827,938 | 706,938 | 894,438 | 892,081 | 707,724 | 814,581 | 863,010 | 885,724 | 770,224 | 817,724 | 821,653 | 9,795,402 | | 9,795,402 |
| | e. Big Bend PM Minimization and Monitoring | 77,000 | 77,000 | 77,000 | 77,000 | 77,000 | 77,000 | 77,000 | 77,000 | 77,000 | 77,000 | 77,000 | 77,000 | 924,000 | | 924,000 |
| | f. Big Bend $NO_x$ Emissions Reduction | 10,000 | 10,000 | 10,000 | 15,000 | 15,000 | 10,000 | 10,000 | 10,000 | 10,000 | 10,000 | 10,000 | 10,000 | 130,000 | | 130,000 |
| | 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 | 1,667 | 1,667 | 1,666 | 1,667 | 1,667 | 1,666 | 1,667 | 1,667 | 1,666 | 1,667 | 1,667 | 1,666 | 20,000 | | 20,000 |
| | j. Bayside SCR and Consumables | 17,000 | 17,000 | 17,000 | 17,000 | 17,000 | 17,000 | 17,000 | 17,000 | 17,000 | 17,000 | 17,000 | 17,000 | 204,000 | | 204,000 |
| | k. Big Bend Unit 4 SOFA | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 42,000 | | 42,000 |
| | l. Big Bend Unit 1 Pre-SCR | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 42,000 | | 42,000 |
| | m. Big Bend Unit 2 Pre-SCR | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 42,000 | | 42,000 |
| | n. Big Bend Unit 3 Pre-SCR | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 42,000 | | 42,000 |
| | o. Clean Water Act Section 316(b) Phase II Study | 80,000 | 80,000 | 80,000 | 80,000 | 80,000 | 80,000 | 80,000 | 80,000 | 80,000 | 80,000 | 80,000 | 80,000 | 960,000 | 960,000 | |
| | p. Arsenic Groundwater Standard Program | 0 | 0 | 6,000 | 0 | 0 | 6,500 | 0 | 0 | 6,000 | 0 | 0 | 6,500 | 25,000 | 25,000 | |
| | q. Big Bend 1 SCR | 171,000 | 171,000 | 175,000 | 140,000 | 171,000 | 173,000 | 178,000 | 178,000 | 178,000 | 170,000 | 170,000 | 150,000 | 2,025,000 | | 2,025,000 |
| | r. Big Bend 2 SCR | 148,000 | 148,000 | 145,000 | 50,000 | 50,000 | 138,000 | 165,000 | 165,000 | 168,000 | 148,000 | 148,000 | 140,000 | 1,613,000 | | 1,613,000 |
| | s. Big Bend 3 SCR | 168,000 | 170,000 | 170,000 | 168,000 | 168,000 | 168,000 | 168,000 | 173,000 | 173,000 | 170,000 | 168,000 | 168,000 | 2,032,000 | | 2,032,000 |
| | t. Big Bend 4 SCR | 170,000 | 175,000 | 155,000 | 175,000 | 170,000 | 170,000 | 180,000 | 180,000 | 180,000 | 170,000 | 175,000 | 170,000 | 2,070,000 | | 2,070,000 |
| | u. Mercury Air Toxics Standards | 36,000 | 11,000 | 13,500 | 33,500 | 14,250 | 13,500 | 31,750 | 11,000 | 11,750 | 31,000 | 11,750 | 11,000 | 230,000 | | 230,000 |
| | v. Greenhouse Gas Reduction Program | 90,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 90,000 | | 90,000 |
| | w. Big Bend Gypsum Storage Facility | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 900,000 | | 900,000 |
| 2. | Total of O&M Activities | 2,366,292 | 2,279,498.00 | 2,148,011 | 2,221,374 | 2,225,760.00 | 2,132,152 | 2,292,749 | 2,325,435 | 2,357,900 | 2,214,649 | 2,267,011 | 2,243,716 | 27,074,547 | $1,019,500 | $26,055,047 |
| 3. | Recoverable Costs Allocated to Energy | 2,251,792 | 2,199,498 | 2,062,011 | 2,141,374 | 2,145,760 | 2,045,652 | 2,212,749 | 2,245,435 | 2,271,900 | 2,134,649 | 2,187,011 | 2,157,216 | 26,055,047 | | |
| 4. | Recoverable Costs Allocated to Demand | 114,500 | 80,000 | 86,000 | 80,000 | 80,000 | 86,500 | 80,000 | 80,000 | 86,000 | 80,000 | 80,000 | 86,500 | 1,019,500 | | |
| 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) | 2,251,792 | 2,199,498 | 2,062,011 | 2,141,374 | 2,145,760 | 2,045,652 | 2,212,749 | 2,245,435 | 2,271,900 | 2,134,649 | 2,187,011 | 2,157,216 | 26,055,047 | | |
| 8. | Jurisdictional Demand Recoverable Costs (B) | 114,500 | 80,000 | 86,000 | 80,000 | 80,000 | 86,500 | 80,000 | 80,000 | 86,000 | 80,000 | 80,000 | 86,500 | 1,019,500 | | |
| 9. | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $2,366,292 | $2,279,498 | $2,148,011 | $2,221,374 | $2,225,760 | $2,132,152 | $2,292,749 | $2,325,435 | $2,357,900 | $2,214,649 | $2,267,011 | $2,243,716 | $27,074,547 | | |

**Notes:**
(A) Line 3 x Line 5
(B) Line 4 x Line 6



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-2P
EXHIBIT NO. ____ (PAR-3) , DOCUMENT NO. 2

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 Flue Gas Desulfurization Integration | $96,132 | $95,917 | $95,702 | $95,487 | $95,272 | $95,057 | $94,842 | $94,627 | $94,412 | $94,197 | $93,982 | $93,767 | $1,139,394 | | $1,139,394 |
| | b. | Big Bend Units 1 and 2 Flue Gas Conditioning | 25,276 | 25,155 | 25,034 | 24,912 | 24,791 | 24,670 | 24,549 | 24,428 | 24,307 | 24,186 | 24,065 | 23,944 | 295,317 | | 295,317 |
| | c. | Big Bend Unit 4 Continuous Emissions Monitors | 5,148 | 5,130 | 5,113 | 5,096 | 5,079 | 5,061 | 5,044 | 5,027 | 5,009 | 4,992 | 4,974 | 4,958 | 60,631 | | 60,631 |
| | d. | Big Bend Fuel Oil Tank # 1 Upgrade | 3,336 | 3,325 | 3,315 | 3,305 | 3,293 | 3,283 | 3,273 | 3,262 | 3,251 | 3,241 | 3,230 | 3,219 | 39,333 | $39,333 | |
| | e. | Big Bend Fuel Oil Tank # 2 Upgrade | 5,487 | 5,469 | 5,452 | 5,435 | 5,417 | 5,399 | 5,383 | 5,365 | 5,347 | 5,330 | 5,313 | 5,296 | 64,693 | 64,693 | |
| | f. | Big Bend Unit 1 Classifier Replacement | 8,120 | 8,087 | 8,054 | 8,021 | 7,989 | 7,956 | 7,923 | 7,889 | 7,856 | 7,824 | 7,791 | 7,758 | 95,268 | | 95,268 |
| | g. | Big Bend Unit 2 Classifier Replacement | 5,866 | 5,843 | 5,820 | 5,797 | 5,774 | 5,753 | 5,730 | 5,707 | 5,684 | 5,661 | 5,638 | 5,615 | 68,888 | | 68,888 |
| | h. | Big Bend Section 114 Mercury Testing Platform | 860 | 857 | 856 | 853 | 851 | 848 | 847 | 845 | 842 | 841 | 838 | 836 | 10,174 | | 10,174 |
| | i. | Big Bend Units 1 & 2 FGD | 604,472 | 603,214 | 601,257 | 599,300 | 597,344 | 595,387 | 593,431 | 591,475 | 589,518 | 587,561 | 585,605 | 583,649 | 7,132,213 | | 7,132,213 |
| | j. | Big Bend FGD Optimization and Utilization | 150,385 | 150,045 | 149,706 | 149,366 | 149,026 | 148,687 | 148,347 | 148,008 | 147,668 | 147,329 | 146,989 | 146,649 | 1,782,205 | | 1,782,205 |
| | k. | Big Bend $NO_x$ Emissions Reduction | 49,956 | 49,880 | 49,803 | 49,727 | 49,650 | 49,574 | 49,498 | 49,422 | 49,345 | 49,268 | 49,192 | 49,115 | 594,430 | | 594,430 |
| | l. | Big Bend PM Minimization and Monitoring | 194,311 | 193,825 | 193,339 | 192,854 | 192,368 | 191,882 | 191,397 | 190,911 | 190,425 | 189,939 | 189,453 | 188,967 | 2,299,671 | | 2,299,671 |
| | m. | Polk $NO_x$ Emissions Reduction | 11,392 | 11,359 | 11,326 | 11,293 | 11,260 | 11,227 | 11,193 | 11,160 | 11,127 | 11,094 | 11,061 | 11,027 | 134,519 | | 134,519 |
| | n. | Big Bend Unit 4 SOFA | 19,896 | 19,848 | 19,800 | 19,752 | 19,705 | 19,656 | 19,608 | 19,560 | 19,512 | 19,465 | 19,416 | 19,368 | 235,586 | | 235,586 |
| | o. | Big Bend Unit 1 Pre-SCR | 13,843 | 13,802 | 13,761 | 13,720 | 13,679 | 13,637 | 13,596 | 13,555 | 13,513 | 13,472 | 13,431 | 13,389 | 163,398 | | 163,398 |
| | p. | Big Bend Unit 2 Pre-SCR | 13,144 | 13,107 | 13,072 | 13,035 | 12,998 | 12,962 | 12,925 | 12,888 | 12,852 | 12,815 | 12,778 | 12,742 | 155,318 | | 155,318 |
| | q. | Big Bend Unit 3 Pre-SCR | 23,414 | 23,355 | 23,295 | 23,236 | 23,176 | 23,116 | 23,056 | 22,997 | 22,937 | 22,877 | 22,817 | 22,759 | 277,035 | | 277,035 |
| | r. | Big Bend Unit 1 SCR | 790,251 | 787,931 | 785,612 | 783,293 | 780,974 | 778,654 | 776,336 | 774,017 | 771,697 | 769,379 | 767,059 | 764,741 | 9,329,944 | | 9,329,944 |
| | s. | Big Bend Unit 2 SCR | 844,591 | 842,283 | 839,974 | 837,666 | 835,358 | 833,049 | 830,741 | 828,433 | 826,124 | 823,816 | 821,508 | 819,199 | 9,982,742 | | 9,982,742 |
| | t. | Big Bend Unit 3 SCR | 684,776 | 682,957 | 681,175 | 681,231 | 681,436 | 681,800 | 680,354 | 682,373 | 688,239 | 688,114 | 687,099 | 685,582 | 8,205,136 | | 8,205,136 |
| | u. | Big Bend Unit 4 SCR | 525,940 | 524,567 | 523,193 | 521,820 | 520,446 | 519,072 | 517,699 | 516,325 | 514,952 | 513,579 | 512,205 | 510,832 | 6,220,630 | | 6,220,630 |
| | v. | Big Bend FGD System Reliability | 208,395 | 208,011 | 207,625 | 207,241 | 206,856 | 206,471 | 206,086 | 205,701 | 205,316 | 204,932 | 204,546 | 204,162 | 2,475,342 | | 2,475,342 |
| | w. | Mercury Air Toxics Standards | 82,564 | 82,400 | 82,234 | 82,069 | 81,904 | 81,739 | 81,574 | 81,408 | 81,244 | 81,079 | 80,913 | 80,748 | 979,876 | | 979,876 |
| | x. | $SO_2$ Emissions Allowances (B) | (264) | (263) | (263) | (263) | (263) | (262) | (262) | (261) | (260) | (260) | (260) | (259) | (3,140) | | (3,140) |
| | y. | Big Bend Gypsum Storage Facility | 205,655 | 205,270 | 204,884 | 204,499 | 204,114 | 203,728 | 203,343 | 202,957 | 202,572 | 202,187 | 201,801 | 201,416 | 2,442,426 | | 2,442,426 |
| 2. | | Total Investment Projects - Recoverable Costs | 4,572,946 | 4,561,374 | 4,549,139 | 4,538,745 | 4,528,497 | 4,518,406 | 4,506,513 | 4,498,079 | 4,493,489 | 4,482,918 | 4,471,444 | 4,459,479 | 54,181,029 | $104,026 | $54,077,003 |
| 3. | | Recoverable Costs Allocated to Energy | 4,564,123 | 4,552,580 | 4,540,372 | 4,530,005 | 4,519,787 | 4,509,724 | 4,497,857 | 4,489,452 | 4,484,891 | 4,474,347 | 4,462,901 | 4,450,964 | 54,077,003 | | 54,077,003 |
| 4. | | Recoverable Costs Allocated to Demand | 8,823 | 8,794 | 8,767 | 8,740 | 8,710 | 8,682 | 8,656 | 8,627 | 8,598 | 8,571 | 8,543 | 8,515 | 104,026 | 104,026 | |
| 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) | 4,564,123 | 4,552,580 | 4,540,372 | 4,530,005 | 4,519,787 | 4,509,724 | 4,497,857 | 4,489,452 | 4,484,891 | 4,474,347 | 4,462,901 | 4,450,964 | 54,077,003 | | |
| 8. | | Jurisdictional Demand Recoverable Costs (D) | 8,823 | 8,794 | 8,767 | 8,740 | 8,710 | 8,682 | 8,656 | 8,627 | 8,598 | 8,571 | 8,543 | 8,515 | 104,026 | | |
| 9. | | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $4,572,946 | $4,561,374 | $4,549,139 | $4,538,745 | $4,528,497 | $4,518,406 | $4,506,513 | $4,498,079 | $4,493,489 | $4,482,918 | $4,471,444 | $4,459,479 | $54,181,029 | | |

**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



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-3P
EXHIBIT NO. ____ (PAR-3) , DOCUMENT NO. 3

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected January | Projected February | Projected March | Projected April | Projected May | Projected June | Projected July | Projected August | Projected September | Projected October | Projected November | Projected December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 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) | $13,757,409 | $13,757,409 | $13,757,409 | $13,757,409 | $13,757,409 | $13,757,409 | $13,757,409 | $13,757,409 | $13,757,409 | $13,757,409 | $13,757,409 | $13,757,409 | $13,757,409 | |
| 3. | Less: Accumulated Depreciation | (4,748,247) | (4,776,908) | (4,805,569) | (4,834,230) | (4,862,891) | (4,891,552) | (4,920,213) | (4,948,874) | (4,977,535) | (5,006,196) | (5,034,857) | (5,063,518) | (5,092,179) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $9,009,162 | 8,980,501 | 8,951,840 | 8,923,179 | 8,894,518 | 8,865,857 | 8,837,196 | 8,808,535 | 8,779,874 | 8,751,213 | 8,722,552 | 8,693,891 | 8,665,230 | |
| 6. | Average Net Investment | | 8,994,832 | 8,966,171 | 8,937,510 | 8,908,849 | 8,880,188 | 8,851,527 | 8,822,866 | 8,794,205 | 8,765,544 | 8,736,883 | 8,708,222 | 8,679,561 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $52,876 | $52,708 | $52,539 | $52,371 | $52,202 | $52,034 | $51,865 | $51,697 | $51,528 | $51,360 | $51,191 | $51,023 | $623,394 |
| | b. Debt Component Grossed Up For Taxes (C) | | 14,595 | 14,548 | 14,502 | 14,455 | 14,409 | 14,362 | 14,316 | 14,269 | 14,223 | 14,176 | 14,130 | 14,083 | 172,068 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 28,661 | 28,661 | 28,661 | 28,661 | 28,661 | 28,661 | 28,661 | 28,661 | 28,661 | 28,661 | 28,661 | 28,661 | $343,932 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 96,132 | 95,917 | 95,702 | 95,487 | 95,272 | 95,057 | 94,842 | 94,627 | 94,412 | 94,197 | 93,982 | 93,767 | 1,139,394 |
| | a. Recoverable Costs Allocated to Energy | | 96,132 | 95,917 | 95,702 | 95,487 | 95,272 | 95,057 | 94,842 | 94,627 | 94,412 | 94,197 | 93,982 | 93,767 | 1,139,394 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 96,132 | 95,917 | 95,702 | 95,487 | 95,272 | 95,057 | 94,842 | 94,627 | 94,412 | 94,197 | 93,982 | 93,767 | 1,139,394 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $96,132 | $95,917 | $95,702 | $95,487 | $95,272 | $95,057 | $94,842 | $94,627 | $94,412 | $94,197 | $93,982 | $93,767 | $1,139,394 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (3,791,894) | (3,808,035) | (3,824,176) | (3,840,317) | (3,856,458) | (3,872,599) | (3,888,740) | (3,904,881) | (3,921,022) | (3,937,163) | (3,953,304) | (3,969,445) | (3,985,586) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,225,840 | 1,209,699 | 1,193,558 | 1,177,417 | 1,161,276 | 1,145,135 | 1,128,994 | 1,112,853 | 1,096,712 | 1,080,571 | 1,064,430 | 1,048,289 | 1,032,148 | |
| 6. | Average Net Investment | | 1,217,770 | 1,201,629 | 1,185,488 | 1,169,347 | 1,153,206 | 1,137,065 | 1,120,924 | 1,104,783 | 1,088,642 | 1,072,501 | 1,056,360 | 1,040,219 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $7,159 | $7,064 | $6,969 | $6,874 | $6,779 | $6,684 | $6,589 | $6,494 | $6,400 | $6,305 | $6,210 | $6,115 | $79,642 |
| | b. Debt Component Grossed Up For Taxes (C) | | 1,976 | 1,950 | 1,924 | 1,897 | 1,871 | 1,845 | 1,819 | 1,793 | 1,766 | 1,740 | 1,714 | 1,688 | 21,983 |
| 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) | | 25,276 | 25,155 | 25,034 | 24,912 | 24,791 | 24,670 | 24,549 | 24,428 | 24,307 | 24,186 | 24,065 | 23,944 | 295,317 |
| | a. Recoverable Costs Allocated to Energy | | 25,276 | 25,155 | 25,034 | 24,912 | 24,791 | 24,670 | 24,549 | 24,428 | 24,307 | 24,186 | 24,065 | 23,944 | 295,317 |
| | b. Recoverable Costs 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) | | 25,276 | 25,155 | 25,034 | 24,912 | 24,791 | 24,670 | 24,549 | 24,428 | 24,307 | 24,186 | 24,065 | 23,944 | 295,317 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $25,276 | $25,155 | $25,034 | $24,912 | $24,791 | $24,670 | $24,549 | $24,428 | $24,307 | $24,186 | $24,065 | $23,944 | $295,317 |

**Notes:**
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% 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. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 2 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (486,725) | (489,035) | (491,345) | (493,655) | (495,965) | (498,275) | (500,585) | (502,895) | (505,205) | (507,515) | (509,825) | (512,135) | (514,445) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $379,486 | 377,176 | 374,866 | 372,556 | 370,246 | 367,936 | 365,626 | 363,316 | 361,006 | 358,696 | 356,386 | 354,076 | 351,766 | |
| 6. | Average Net Investment | | 378,331 | 376,021 | 373,711 | 371,401 | 369,091 | 366,781 | 364,471 | 362,161 | 359,851 | 357,541 | 355,231 | 352,921 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $2,224 | $2,210 | $2,197 | $2,183 | $2,170 | $2,156 | $2,143 | $2,129 | $2,115 | $2,102 | $2,088 | $2,075 | $25,792 |
| | b. Debt Component Grossed Up For Taxes (C) | | 614 | 610 | 606 | 603 | 599 | 595 | 591 | 588 | 584 | 580 | 576 | 573 | 7,119 |
| 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) | | 5,148 | 5,130 | 5,113 | 5,096 | 5,079 | 5,061 | 5,044 | 5,027 | 5,009 | 4,992 | 4,974 | 4,958 | 60,631 |
| | a. Recoverable Costs Allocated to Energy | | 5,148 | 5,130 | 5,113 | 5,096 | 5,079 | 5,061 | 5,044 | 5,027 | 5,009 | 4,992 | 4,974 | 4,958 | 60,631 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 5,148 | 5,130 | 5,113 | 5,096 | 5,079 | 5,061 | 5,044 | 5,027 | 5,009 | 4,992 | 4,974 | 4,958 | 60,631 |
| 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) | | $5,148 | $5,130 | $5,113 | $5,096 | $5,079 | $5,061 | $5,044 | $5,027 | $5,009 | $4,992 | $4,974 | $4,958 | $60,631 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 3 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (240,112) | (241,522) | (242,932) | (244,342) | (245,752) | (247,162) | (248,572) | (249,982) | (251,392) | (252,802) | (254,212) | (255,622) | (257,032) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $257,466 | 256,056 | 254,646 | 253,236 | 251,826 | 250,416 | 249,006 | 247,596 | 246,186 | 244,776 | 243,366 | 241,956 | 240,546 | |
| 6. | Average Net Investment | | 256,761 | 255,351 | 253,941 | 252,531 | 251,121 | 249,711 | 248,301 | 246,891 | 245,481 | 244,071 | 242,661 | 241,251 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $1,509 | $1,501 | $1,493 | $1,485 | $1,476 | $1,468 | $1,460 | $1,451 | $1,443 | $1,435 | $1,426 | $1,418 | $17,565 |
| | b. Debt Component Grossed Up For Taxes (C) | | 417 | 414 | 412 | 410 | 407 | 405 | 403 | 401 | 398 | 396 | 394 | 391 | 4,848 |
| 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) | | 3,336 | 3,325 | 3,315 | 3,305 | 3,293 | 3,283 | 3,273 | 3,262 | 3,251 | 3,241 | 3,230 | 3,219 | 39,333 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 3,336 | 3,325 | 3,315 | 3,305 | 3,293 | 3,283 | 3,273 | 3,262 | 3,251 | 3,241 | 3,230 | 3,219 | 39,333 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 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) | | 3,336 | 3,325 | 3,315 | 3,305 | 3,293 | 3,283 | 3,273 | 3,262 | 3,251 | 3,241 | 3,230 | 3,219 | 39,333 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $3,336 | $3,325 | $3,315 | $3,305 | $3,293 | $3,283 | $3,273 | $3,262 | $3,251 | $3,241 | $3,230 | $3,219 | $39,333 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 4 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (394,936) | (397,255) | (399,574) | (401,893) | (404,212) | (406,531) | (408,850) | (411,169) | (413,488) | (415,807) | (418,126) | (420,445) | (422,764) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $423,465 | 421,146 | 418,827 | 416,508 | 414,189 | 411,870 | 409,551 | 407,232 | 404,913 | 402,594 | 400,275 | 397,956 | 395,637 | |
| 6. | Average Net Investment | | 422,306 | 419,987 | 417,668 | 415,349 | 413,030 | 410,711 | 408,392 | 406,073 | 403,754 | 401,435 | 399,116 | 396,797 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $2,483 | $2,469 | $2,455 | $2,442 | $2,428 | $2,414 | $2,401 | $2,387 | $2,373 | $2,360 | $2,346 | $2,333 | $28,891 |
| | b. Debt Component Grossed Up For Taxes (C) | | 685 | 681 | 678 | 674 | 670 | 666 | 663 | 659 | 655 | 651 | 648 | 644 | 7,974 |
| 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) | | 5,487 | 5,469 | 5,452 | 5,435 | 5,417 | 5,399 | 5,383 | 5,365 | 5,347 | 5,330 | 5,313 | 5,296 | 64,693 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 5,487 | 5,469 | 5,452 | 5,435 | 5,417 | 5,399 | 5,383 | 5,365 | 5,347 | 5,330 | 5,313 | 5,296 | 64,693 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 5,487 | 5,469 | 5,452 | 5,435 | 5,417 | 5,399 | 5,383 | 5,365 | 5,347 | 5,330 | 5,313 | 5,296 | 64,693 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $5,487 | $5,469 | $5,452 | $5,435 | $5,417 | $5,399 | $5,383 | $5,365 | $5,347 | $5,330 | $5,313 | $5,296 | $64,693 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 5 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (816,536) | (820,924) | (825,312) | (829,700) | (834,088) | (838,476) | (842,864) | (847,252) | (851,640) | (856,028) | (860,416) | (864,804) | (869,192) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $499,721 | 495,333 | 490,945 | 486,557 | 482,169 | 477,781 | 473,393 | 469,005 | 464,617 | 460,229 | 455,841 | 451,453 | 447,065 | |
| 6. | Average Net Investment | | 497,527 | 493,139 | 488,751 | 484,363 | 479,975 | 475,587 | 471,199 | 466,811 | 462,423 | 458,035 | 453,647 | 449,259 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $2,925 | $2,899 | $2,873 | $2,847 | $2,822 | $2,796 | $2,770 | $2,744 | $2,718 | $2,693 | $2,667 | $2,641 | $33,395 |
| | b. Debt Component Grossed Up For Taxes (C) | | 807 | 800 | 793 | 786 | 779 | 772 | 765 | 757 | 750 | 743 | 736 | 729 | 9,217 |
| 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) | | 8,120 | 8,087 | 8,054 | 8,021 | 7,989 | 7,956 | 7,923 | 7,889 | 7,856 | 7,824 | 7,791 | 7,758 | 95,268 |
| | a. Recoverable Costs Allocated to Energy | | 8,120 | 8,087 | 8,054 | 8,021 | 7,989 | 7,956 | 7,923 | 7,889 | 7,856 | 7,824 | 7,791 | 7,758 | 95,268 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 8,120 | 8,087 | 8,054 | 8,021 | 7,989 | 7,956 | 7,923 | 7,889 | 7,856 | 7,824 | 7,791 | 7,758 | 95,268 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $8,120 | $8,087 | $8,054 | $8,021 | $7,989 | $7,956 | $7,923 | $7,889 | $7,856 | $7,824 | $7,791 | $7,758 | $95,268 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 6 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (606,006) | (609,042) | (612,078) | (615,114) | (618,150) | (621,186) | (624,222) | (627,258) | (630,294) | (633,330) | (636,366) | (639,402) | (642,438) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $378,788 | 375,752 | 372,716 | 369,680 | 366,644 | 363,608 | 360,572 | 357,536 | 354,500 | 351,464 | 348,428 | 345,392 | 342,356 | |
| 6. | Average Net Investment | | 377,270 | 374,234 | 371,198 | 368,162 | 365,126 | 362,090 | 359,054 | 356,018 | 352,982 | 349,946 | 346,910 | 343,874 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $2,218 | $2,200 | $2,182 | $2,164 | $2,146 | $2,129 | $2,111 | $2,093 | $2,075 | $2,057 | $2,039 | $2,021 | $25,435 |
| | b. Debt Component Grossed Up For Taxes (C) | | 612 | 607 | 602 | 597 | 592 | 588 | 583 | 578 | 573 | 568 | 563 | 558 | 7,021 |
| 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) | | 5,866 | 5,843 | 5,820 | 5,797 | 5,774 | 5,753 | 5,730 | 5,707 | 5,684 | 5,661 | 5,638 | 5,615 | 68,888 |
| | a. Recoverable Costs Allocated to Energy | | 5,866 | 5,843 | 5,820 | 5,797 | 5,774 | 5,753 | 5,730 | 5,707 | 5,684 | 5,661 | 5,638 | 5,615 | 68,888 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 5,866 | 5,843 | 5,820 | 5,797 | 5,774 | 5,753 | 5,730 | 5,707 | 5,684 | 5,661 | 5,638 | 5,615 | 68,888 |
| 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) | | $5,866 | $5,843 | $5,820 | $5,797 | $5,774 | $5,753 | $5,730 | $5,707 | $5,684 | $5,661 | $5,638 | $5,615 | $68,888 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 7 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (44,899) | (45,191) | (45,483) | (45,775) | (46,067) | (46,359) | (46,651) | (46,943) | (47,235) | (47,527) | (47,819) | (48,111) | (48,403) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $75,838 | 75,546 | 75,254 | 74,962 | 74,670 | 74,378 | 74,086 | 73,794 | 73,502 | 73,210 | 72,918 | 72,626 | 72,334 | |
| 6. | Average Net Investment | | 75,692 | 75,400 | 75,108 | 74,816 | 74,524 | 74,232 | 73,940 | 73,648 | 73,356 | 73,064 | 72,772 | 72,480 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $445 | $443 | $442 | $440 | $438 | $436 | $435 | $433 | $431 | $430 | $428 | $426 | $5,227 |
| | b. Debt Component Grossed Up For Taxes (C) | | 123 | 122 | 122 | 121 | 121 | 120 | 120 | 120 | 119 | 119 | 118 | 118 | 1,443 |
| 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) | | 860 | 857 | 856 | 853 | 851 | 848 | 847 | 845 | 842 | 841 | 838 | 836 | 10,174 |
| | a. Recoverable Costs Allocated to Energy | | 860 | 857 | 856 | 853 | 851 | 848 | 847 | 845 | 842 | 841 | 838 | 836 | 10,174 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 860 | 857 | 856 | 853 | 851 | 848 | 847 | 845 | 842 | 841 | 838 | 836 | 10,174 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $860 | $857 | $856 | $853 | $851 | $848 | $847 | $845 | $842 | $841 | $838 | $836 | $10,174 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 8 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | | 107,274 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 107,274 |
| | 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) | $94,740,488 | $94,847,762 | $94,847,762 | $94,847,762 | $94,847,762 | $94,847,762 | $94,847,762 | $94,847,762 | $94,847,762 | $94,847,762 | $94,847,762 | $94,847,762 | $94,847,762 | |
| 3. | Less: Accumulated Depreciation | (48,813,133) | (49,073,669) | (49,334,500) | (49,595,331) | (49,856,162) | (50,116,993) | (50,377,824) | (50,638,655) | (50,899,486) | (51,160,317) | (51,421,148) | (51,681,979) | (51,942,810) | |
| 4. | CWIP - Non-Interest Bearing | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $45,928,088 | 45,774,826 | 45,513,995 | 45,253,164 | 44,992,333 | 44,731,502 | 44,470,671 | 44,209,840 | 43,949,009 | 43,688,178 | 43,427,347 | 43,166,516 | 42,905,685 | |
| 6. | Average Net Investment | | 45,851,457 | 45,644,410 | 45,383,579 | 45,122,748 | 44,861,917 | 44,601,086 | 44,340,255 | 44,079,424 | 43,818,593 | 43,557,762 | 43,296,931 | 43,036,100 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $269,538 | $268,321 | $266,787 | $265,254 | $263,721 | $262,187 | $260,654 | $259,121 | $257,588 | $256,054 | $254,521 | $252,988 | $3,136,734 |
| | b. Debt Component Grossed Up For Taxes (C) | | 74,398 | 74,062 | 73,639 | 73,215 | 72,792 | 72,369 | 71,946 | 71,523 | 71,099 | 70,676 | 70,253 | 69,830 | 865,802 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $260,536 | $260,831 | $260,831 | $260,831 | $260,831 | $260,831 | $260,831 | $260,831 | $260,831 | $260,831 | $260,831 | $260,831 | $3,129,677 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 604,472 | 603,214 | 601,257 | 599,300 | 597,344 | 595,387 | 593,431 | 591,475 | 589,518 | 587,561 | 585,605 | 583,649 | 7,132,213 |
| | a. Recoverable Costs Allocated to Energy | | 604,472 | 603,214 | 601,257 | 599,300 | 597,344 | 595,387 | 593,431 | 591,475 | 589,518 | 587,561 | 585,605 | 583,649 | 7,132,213 |
| | 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) | | 604,472 | 603,214 | 601,257 | 599,300 | 597,344 | 595,387 | 593,431 | 591,475 | 589,518 | 587,561 | 585,605 | 583,649 | 7,132,213 |
| 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) | | $604,472 | $603,214 | $601,257 | $599,300 | $597,344 | $595,387 | $593,431 | $591,475 | $589,518 | $587,561 | $585,605 | $583,649 | $7,132,213 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rates are 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 9 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected January | Projected February | Projected March | Projected April | Projected May | Projected June | Projected July | Projected August | Projected September | Projected October | Projected November | Projected December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $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 | (7,704,349) | (7,749,623) | (7,794,897) | (7,840,171) | (7,885,445) | (7,930,719) | (7,975,993) | (8,021,267) | (8,066,541) | (8,111,815) | (8,157,089) | (8,202,363) | (8,247,637) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $14,035,388 | 13,990,114 | 13,944,840 | 13,899,566 | 13,854,292 | 13,809,018 | 13,763,744 | 13,718,470 | 13,673,196 | 13,627,922 | 13,582,648 | 13,537,374 | 13,492,100 | |
| 6. | Average Net Investment | | 14,012,751 | 13,967,477 | 13,922,203 | 13,876,929 | 13,831,655 | 13,786,381 | 13,741,107 | 13,695,833 | 13,650,559 | 13,605,285 | 13,560,011 | 13,514,737 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $82,374 | $82,108 | $81,842 | $81,576 | $81,309 | $81,043 | $80,777 | $80,511 | $80,245 | $79,979 | $79,713 | $79,446 | $970,923 |
| | b. Debt Component Grossed Up For Taxes (C) | | 22,737 | 22,663 | 22,590 | 22,516 | 22,443 | 22,370 | 22,296 | 22,223 | 22,149 | 22,076 | 22,002 | 21,929 | 267,994 |
| 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) | | 150,385 | 150,045 | 149,706 | 149,366 | 149,026 | 148,687 | 148,347 | 148,008 | 147,668 | 147,329 | 146,989 | 146,649 | 1,782,205 |
| | a. Recoverable Costs Allocated to Energy | | 150,385 | 150,045 | 149,706 | 149,366 | 149,026 | 148,687 | 148,347 | 148,008 | 147,668 | 147,329 | 146,989 | 146,649 | 1,782,205 |
| | b. Recoverable Costs 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) | | 150,385 | 150,045 | 149,706 | 149,366 | 149,026 | 148,687 | 148,347 | 148,008 | 147,668 | 147,329 | 146,989 | 146,649 | 1,782,205 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $150,385 | $150,045 | $149,706 | $149,366 | $149,026 | $148,687 | $148,347 | $148,008 | $147,668 | $147,329 | $146,989 | $146,649 | $1,782,205 |

**Notes:**
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,699,919)and 311.45 ($39,818)
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rates are 2.5% and 2.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4,PAGE 10 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | 2,116,395 | 2,106,211 | 2,096,027 | 2,085,843 | 2,075,659 | 2,065,475 | 2,055,291 | 2,045,107 | 2,034,923 | 2,024,739 | 2,014,555 | 2,004,371 | 1,994,187 | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $5,307,247 | 5,297,063 | 5,286,879 | 5,276,695 | 5,266,511 | 5,256,327 | 5,246,143 | 5,235,959 | 5,225,775 | 5,215,591 | 5,205,407 | 5,195,223 | 5,185,039 | |
| 6. | Average Net Investment | | 5,302,155 | 5,291,971 | 5,281,787 | 5,271,603 | 5,261,419 | 5,251,235 | 5,241,051 | 5,230,867 | 5,220,683 | 5,210,499 | 5,200,315 | 5,190,131 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $31,169 | $31,109 | $31,049 | $30,989 | $30,929 | $30,869 | $30,810 | $30,750 | $30,690 | $30,630 | $30,570 | $30,510 | $370,074 |
| | b. Debt Component Grossed Up For Taxes (C) | | 8,603 | 8,587 | 8,570 | 8,554 | 8,537 | 8,521 | 8,504 | 8,488 | 8,471 | 8,454 | 8,438 | 8,421 | 102,148 |
| 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) | | 49,956 | 49,880 | 49,803 | 49,727 | 49,650 | 49,574 | 49,498 | 49,422 | 49,345 | 49,268 | 49,192 | 49,115 | 594,430 |
| | a. Recoverable Costs Allocated to Energy | | 49,956 | 49,880 | 49,803 | 49,727 | 49,650 | 49,574 | 49,498 | 49,422 | 49,345 | 49,268 | 49,192 | 49,115 | 594,430 |
| | b. Recoverable Costs 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) | | 49,956 | 49,880 | 49,803 | 49,727 | 49,650 | 49,574 | 49,498 | 49,422 | 49,345 | 49,268 | 49,192 | 49,115 | 594,430 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $49,956 | $49,880 | $49,803 | $49,727 | $49,650 | $49,574 | $49,498 | $49,422 | $49,345 | $49,268 | $49,192 | $49,115 | $594,430 |

**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 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% 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



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4,PAGE 11 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected January | Projected February | Projected March | Projected April | Projected May | Projected June | Projected July | Projected August | Projected September | Projected October | Projected November | Projected December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $20,924,650 | $20,924,650 | $20,924,650 | $20,924,650 | $20,924,650 | $20,924,650 | $20,924,650 | $20,924,650 | $20,924,650 | $20,924,650 | $20,924,650 | $20,924,650 | $20,924,650 | |
| 3. | Less: Accumulated Depreciation | (3,621,563) | (3,686,325) | (3,751,087) | (3,815,849) | (3,880,611) | (3,945,373) | (4,010,135) | (4,074,897) | (4,139,659) | (4,204,421) | (4,269,183) | (4,333,945) | (4,398,707) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $17,303,087 | 17,238,325 | 17,173,563 | 17,108,801 | 17,044,039 | 16,979,277 | 16,914,515 | 16,849,753 | 16,784,991 | 16,720,229 | 16,655,467 | 16,590,705 | 16,525,943 | |
| 6. | Average Net Investment | | 17,270,706 | 17,205,944 | 17,141,182 | 17,076,420 | 17,011,658 | 16,946,896 | 16,882,134 | 16,817,372 | 16,752,610 | 16,687,848 | 16,623,086 | 16,558,324 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $101,526 | $101,145 | $100,764 | $100,384 | $100,003 | $99,622 | $99,242 | $98,861 | $98,480 | $98,100 | $97,719 | $97,338 | $1,193,184 |
| | b. Debt Component Grossed Up For Taxes (C) | | 28,023 | 27,918 | 27,813 | 27,708 | 27,603 | 27,498 | 27,393 | 27,288 | 27,183 | 27,077 | 26,972 | 26,867 | 329,343 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $64,762 | $64,762 | $64,762 | $64,762 | $64,762 | $64,762 | $64,762 | $64,762 | $64,762 | $64,762 | $64,762 | $64,762 | $777,144 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 194,311 | 193,825 | 193,339 | 192,854 | 192,368 | 191,882 | 191,397 | 190,911 | 190,425 | 189,939 | 189,453 | 188,967 | 2,299,671 |
| | a. Recoverable Costs Allocated to Energy | | 194,311 | 193,825 | 193,339 | 192,854 | 192,368 | 191,882 | 191,397 | 190,911 | 190,425 | 189,939 | 189,453 | 188,967 | 2,299,671 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 194,311 | 193,825 | 193,339 | 192,854 | 192,368 | 191,882 | 191,397 | 190,911 | 190,425 | 189,939 | 189,453 | 188,967 | 2,299,671 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $194,311 | $193,825 | $193,339 | $192,854 | $192,368 | $191,882 | $191,397 | $190,911 | $190,425 | $189,939 | $189,453 | $188,967 | $2,299,671 |

**Notes:**

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($6,998,365), 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 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% 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



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4,PAGE 12 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (630,234) | (634,658) | (639,082) | (643,506) | (647,930) | (652,354) | (656,778) | (661,202) | (665,626) | (670,050) | (674,474) | (678,898) | (683,322) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $931,239 | 926,815 | 922,391 | 917,967 | 913,543 | 909,119 | 904,695 | 900,271 | 895,847 | 891,423 | 886,999 | 882,575 | 878,151 | |
| 6. | Average Net Investment | | 929,027 | 924,603 | 920,179 | 915,755 | 911,331 | 906,907 | 902,483 | 898,059 | 893,635 | 889,211 | 884,787 | 880,363 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $5,461 | $5,435 | $5,409 | $5,383 | $5,357 | $5,331 | $5,305 | $5,279 | $5,253 | $5,227 | $5,201 | $5,175 | $63,816 |
| | b. Debt Component Grossed Up For Taxes (C) | | 1,507 | 1,500 | 1,493 | 1,486 | 1,479 | 1,472 | 1,464 | 1,457 | 1,450 | 1,443 | 1,436 | 1,428 | 17,615 |
| 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) | | 11,392 | 11,359 | 11,326 | 11,293 | 11,260 | 11,227 | 11,193 | 11,160 | 11,127 | 11,094 | 11,061 | 11,027 | 134,519 |
| | a. Recoverable Costs Allocated to Energy | | 11,392 | 11,359 | 11,326 | 11,293 | 11,260 | 11,227 | 11,193 | 11,160 | 11,127 | 11,094 | 11,061 | 11,027 | 134,519 |
| | b. Recoverable Costs 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) | | 11,392 | 11,359 | 11,326 | 11,293 | 11,260 | 11,227 | 11,193 | 11,160 | 11,127 | 11,094 | 11,061 | 11,027 | 134,519 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $11,392 | $11,359 | $11,326 | $11,293 | $11,260 | $11,227 | $11,193 | $11,160 | $11,127 | $11,094 | $11,061 | $11,027 | $134,519 |

**Notes:**
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 13 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (755,906) | (762,303) | (768,700) | (775,097) | (781,494) | (787,891) | (794,288) | (800,685) | (807,082) | (813,479) | (819,876) | (826,273) | (832,670) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,802,824 | 1,796,427 | 1,790,030 | 1,783,633 | 1,777,236 | 1,770,839 | 1,764,442 | 1,758,045 | 1,751,648 | 1,745,251 | 1,738,854 | 1,732,457 | 1,726,060 | |
| 6. | Average Net Investment | | 1,799,626 | 1,793,229 | 1,786,832 | 1,780,435 | 1,774,038 | 1,767,641 | 1,761,244 | 1,754,847 | 1,748,450 | 1,742,053 | 1,735,656 | 1,729,259 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $10,579 | $10,541 | $10,504 | $10,466 | $10,429 | $10,391 | $10,353 | $10,316 | $10,278 | $10,241 | $10,203 | $10,165 | $124,466 |
| | b. Debt Component Grossed Up For Taxes (C) | | 2,920 | 2,910 | 2,899 | 2,889 | 2,879 | 2,868 | 2,858 | 2,847 | 2,837 | 2,827 | 2,816 | 2,806 | 34,356 |
| 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) | | 19,896 | 19,848 | 19,800 | 19,752 | 19,705 | 19,656 | 19,608 | 19,560 | 19,512 | 19,465 | 19,416 | 19,368 | 235,586 |
| | a. Recoverable Costs Allocated to Energy | | 19,896 | 19,848 | 19,800 | 19,752 | 19,705 | 19,656 | 19,608 | 19,560 | 19,512 | 19,465 | 19,416 | 19,368 | 235,586 |
| | b. Recoverable Costs 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) | | 19,896 | 19,848 | 19,800 | 19,752 | 19,705 | 19,656 | 19,608 | 19,560 | 19,512 | 19,465 | 19,416 | 19,368 | 235,586 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $19,896 | $19,848 | $19,800 | $19,752 | $19,705 | $19,656 | $19,608 | $19,560 | $19,512 | $19,465 | $19,416 | $19,368 | $235,586 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 14 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (533,701) | (539,198) | (544,695) | (550,192) | (555,689) | (561,186) | (566,683) | (572,180) | (577,677) | (583,174) | (588,671) | (594,168) | (599,665) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,115,420 | 1,109,923 | 1,104,426 | 1,098,929 | 1,093,432 | 1,087,935 | 1,082,438 | 1,076,941 | 1,071,444 | 1,065,947 | 1,060,450 | 1,054,953 | 1,049,456 | |
| 6. | Average Net Investment | | 1,112,672 | 1,107,175 | 1,101,678 | 1,096,181 | 1,090,684 | 1,085,187 | 1,079,690 | 1,074,193 | 1,068,696 | 1,063,199 | 1,057,702 | 1,052,205 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $6,541 | $6,509 | $6,476 | $6,444 | $6,412 | $6,379 | $6,347 | $6,315 | $6,282 | $6,250 | $6,218 | $6,185 | $76,358 |
| | b. Debt Component Grossed Up For Taxes (C) | | 1,805 | 1,796 | 1,788 | 1,779 | 1,770 | 1,761 | 1,752 | 1,743 | 1,734 | 1,725 | 1,716 | 1,707 | 21,076 |
| 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) | | 13,843 | 13,802 | 13,761 | 13,720 | 13,679 | 13,637 | 13,596 | 13,555 | 13,513 | 13,472 | 13,431 | 13,389 | 163,398 |
| | a. Recoverable Costs Allocated to Energy | | 13,843 | 13,802 | 13,761 | 13,720 | 13,679 | 13,637 | 13,596 | 13,555 | 13,513 | 13,472 | 13,431 | 13,389 | 163,398 |
| | b. Recoverable Costs 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) | | 13,843 | 13,802 | 13,761 | 13,720 | 13,679 | 13,637 | 13,596 | 13,555 | 13,513 | 13,472 | 13,431 | 13,389 | 163,398 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $13,843 | $13,802 | $13,761 | $13,720 | $13,679 | $13,637 | $13,596 | $13,555 | $13,513 | $13,472 | $13,431 | $13,389 | $163,398 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% 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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ECRC 2016 PROJECTION, FORM 42-4P
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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (477,272) | (482,149) | (487,026) | (491,903) | (496,780) | (501,657) | (506,534) | (511,411) | (516,288) | (521,165) | (526,042) | (530,919) | (535,796) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,104,615 | 1,099,738 | 1,094,861 | 1,089,984 | 1,085,107 | 1,080,230 | 1,075,353 | 1,070,476 | 1,065,599 | 1,060,722 | 1,055,845 | 1,050,968 | 1,046,091 | |
| 6. | Average Net Investment | | 1,102,177 | 1,097,300 | 1,092,423 | 1,087,546 | 1,082,669 | 1,077,792 | 1,072,915 | 1,068,038 | 1,063,161 | 1,058,284 | 1,053,407 | 1,048,530 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $6,479 | $6,450 | $6,422 | $6,393 | $6,364 | $6,336 | $6,307 | $6,278 | $6,250 | $6,221 | $6,192 | $6,164 | $75,856 |
| | b. Debt Component Grossed Up For Taxes (C) | | 1,788 | 1,780 | 1,773 | 1,765 | 1,757 | 1,749 | 1,741 | 1,733 | 1,725 | 1,717 | 1,709 | 1,701 | 20,938 |
| 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) | | 13,144 | 13,107 | 13,072 | 13,035 | 12,998 | 12,962 | 12,925 | 12,888 | 12,852 | 12,815 | 12,778 | 12,742 | 155,318 |
| | a. Recoverable Costs Allocated to Energy | | 13,144 | 13,107 | 13,072 | 13,035 | 12,998 | 12,962 | 12,925 | 12,888 | 12,852 | 12,815 | 12,778 | 12,742 | 155,318 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 13,144 | 13,107 | 13,072 | 13,035 | 12,998 | 12,962 | 12,925 | 12,888 | 12,852 | 12,815 | 12,778 | 12,742 | 155,318 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $13,144 | $13,107 | $13,072 | $13,035 | $12,998 | $12,962 | $12,925 | $12,888 | $12,852 | $12,815 | $12,778 | $12,742 | $155,318 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% 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 2016 to December 2016**

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 | (641,330) | (649,283) | (657,236) | (665,189) | (673,142) | (681,095) | (689,048) | (697,001) | (704,954) | (712,907) | (720,860) | (728,813) | (736,766) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $2,065,177 | 2,057,224 | 2,049,271 | 2,041,318 | 2,033,365 | 2,025,412 | 2,017,459 | 2,009,506 | 2,001,553 | 1,993,600 | 1,985,647 | 1,977,694 | 1,969,741 | |
| 6. | Average Net Investment | | 2,061,201 | 2,053,248 | 2,045,295 | 2,037,342 | 2,029,389 | 2,021,436 | 2,013,483 | 2,005,530 | 1,997,577 | 1,989,624 | 1,981,671 | 1,973,718 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $12,117 | $12,070 | $12,023 | $11,977 | $11,930 | $11,883 | $11,836 | $11,790 | $11,743 | $11,696 | $11,649 | $11,603 | $142,317 |
| | b. Debt Component Grossed Up For Taxes (C) | | 3,344 | 3,332 | 3,319 | 3,306 | 3,293 | 3,280 | 3,267 | 3,254 | 3,241 | 3,228 | 3,215 | 3,203 | 39,282 |
| 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) | | 23,414 | 23,355 | 23,295 | 23,236 | 23,176 | 23,116 | 23,056 | 22,997 | 22,937 | 22,877 | 22,817 | 22,759 | 277,035 |
| | a. Recoverable Costs Allocated to Energy | | 23,414 | 23,355 | 23,295 | 23,236 | 23,176 | 23,116 | 23,056 | 22,997 | 22,937 | 22,877 | 22,817 | 22,759 | 277,035 |
| | b. Recoverable Costs 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) | | 23,414 | 23,355 | 23,295 | 23,236 | 23,176 | 23,116 | 23,056 | 22,997 | 22,937 | 22,877 | 22,817 | 22,759 | 277,035 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $23,414 | $23,355 | $23,295 | $23,236 | $23,176 | $23,116 | $23,056 | $22,997 | $22,937 | $22,877 | $22,817 | $22,759 | $277,035 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 3.5% and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected January | Projected February | Projected March | Projected April | Projected May | Projected June | Projected July | Projected August | Projected September | Projected October | Projected November | Projected December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | $85,719,423 | |
| 3. | Less: Accumulated Depreciation | (21,429,656) | (21,738,823) | (22,047,990) | (22,357,157) | (22,666,324) | (22,975,491) | (23,284,658) | (23,593,825) | (23,902,992) | (24,212,159) | (24,521,326) | (24,830,493) | (25,139,660) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $64,289,767 | 63,980,600 | 63,671,433 | 63,362,266 | 63,053,099 | 62,743,932 | 62,434,765 | 62,125,598 | 61,816,431 | 61,507,264 | 61,198,097 | 60,888,930 | 60,579,763 | |
| 6. | Average Net Investment | | 64,135,184 | 63,826,017 | 63,516,850 | 63,207,683 | 62,898,516 | 62,589,349 | 62,280,182 | 61,971,015 | 61,661,848 | 61,352,681 | 61,043,514 | 60,734,347 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $377,019 | $375,201 | $373,384 | $371,566 | $369,749 | $367,931 | $366,114 | $364,297 | $362,479 | $360,662 | $358,844 | $357,027 | $4,404,273 |
| | b. Debt Component Grossed Up For Taxes (C) | | 104,065 | 103,563 | 103,061 | 102,560 | 102,058 | 101,556 | 101,055 | 100,553 | 100,051 | 99,550 | 99,048 | 98,547 | 1,215,667 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $309,167 | $309,167 | $309,167 | $309,167 | $309,167 | $309,167 | $309,167 | $309,167 | $309,167 | $309,167 | $309,167 | $309,167 | $3,710,004 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 790,251 | 787,931 | 785,612 | 783,293 | 780,974 | 778,654 | 776,336 | 774,017 | 771,697 | 769,379 | 767,059 | 764,741 | 9,329,944 |
| | a. Recoverable Costs Allocated to Energy | | 790,251 | 787,931 | 785,612 | 783,293 | 780,974 | 778,654 | 776,336 | 774,017 | 771,697 | 769,379 | 767,059 | 764,741 | 9,329,944 |
| | b. Recoverable Costs 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) | | 790,251 | 787,931 | 785,612 | 783,293 | 780,974 | 778,654 | 776,336 | 774,017 | 771,697 | 769,379 | 767,059 | 764,741 | 9,329,944 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $790,251 | $787,931 | $785,612 | $783,293 | $780,974 | $778,654 | $776,336 | $774,017 | $771,697 | $769,379 | $767,059 | $764,741 | $9,329,944 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 311.51 ($22,278,982), 312.51 ($48,529,993), 315.51 ($14,063,245), and 316.51 ($847,203).
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 4.1%, 4.3%, 4.8% and 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected January | Projected February | Projected March | Projected April | Projected May | Projected June | Projected July | Projected August | Projected September | Projected October | Projected November | Projected December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $95,145,874 | $95,145,874 | $95,145,874 | $95,145,874 | $95,145,874 | $95,145,874 | $95,145,874 | $95,145,874 | $95,145,874 | $95,145,874 | $95,145,874 | $95,145,874 | $95,145,874 | |
| 3. | Less: Accumulated Depreciation | (23,421,656) | (23,729,392) | (24,037,128) | (24,344,864) | (24,652,600) | (24,960,336) | (25,268,072) | (25,575,808) | (25,883,544) | (26,191,280) | (26,499,016) | (26,806,752) | (27,114,488) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $71,724,218 | 71,416,482 | 71,108,746 | 70,801,010 | 70,493,274 | 70,185,538 | 69,877,802 | 69,570,066 | 69,262,330 | 68,954,594 | 68,646,858 | 68,339,122 | 68,031,386 | |
| 6. | Average Net Investment | | 71,570,350 | 71,262,614 | 70,954,878 | 70,647,142 | 70,339,406 | 70,031,670 | 69,723,934 | 69,416,198 | 69,108,462 | 68,800,726 | 68,492,990 | 68,185,254 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $420,726 | $418,917 | $417,108 | $415,299 | $413,490 | $411,681 | $409,872 | $408,063 | $406,254 | $404,445 | $402,636 | $400,827 | $4,929,318 |
| | b. Debt Component Grossed Up For Taxes (C) | | 116,129 | 115,630 | 115,130 | 114,631 | 114,132 | 113,632 | 113,133 | 112,634 | 112,134 | 111,635 | 111,136 | 110,636 | 1,360,592 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $307,736 | $307,736 | $307,736 | $307,736 | $307,736 | $307,736 | $307,736 | $307,736 | $307,736 | $307,736 | $307,736 | $307,736 | $3,692,832 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 844,591 | 842,283 | 839,974 | 837,666 | 835,358 | 833,049 | 830,741 | 828,433 | 826,124 | 823,816 | 821,508 | 819,199 | 9,982,742 |
| | a. Recoverable Costs Allocated to Energy | | 844,591 | 842,283 | 839,974 | 837,666 | 835,358 | 833,049 | 830,741 | 828,433 | 826,124 | 823,816 | 821,508 | 819,199 | 9,982,742 |
| | b. Recoverable Costs 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) | | 844,591 | 842,283 | 839,974 | 837,666 | 835,358 | 833,049 | 830,741 | 828,433 | 826,124 | 823,816 | 821,508 | 819,199 | 9,982,742 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $844,591 | $842,283 | $839,974 | $837,666 | $835,358 | $833,049 | $830,741 | $828,433 | $826,124 | $823,816 | $821,508 | $819,199 | $9,982,742 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($53,063,962), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rates are 3.5%, 4.0%, 4.1% and 3.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 19 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | $10,000 | $10,000 | $500,000 | $50,000 | $50,000 | $20,000 | $1,000,000 | $200,000 | $100,000 | $50,000 | $10,000 | $2,000,000 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 570,000 | 50,000 | 20,000 | 1,000,000 | 200,000 | 100,000 | 50,000 | 10,000 | 2,000,000 |
| | 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) | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,369,887 | $80,939,887 | $80,989,887 | $81,009,887 | $82,009,887 | $82,209,887 | $82,309,887 | $82,359,887 | $82,369,887 | |
| 3. | Less: Accumulated Depreciation | (21,956,533) | (22,204,074) | (22,451,615) | (22,699,156) | (22,946,697) | (23,194,238) | (23,443,631) | (23,693,187) | (23,942,808) | (24,195,679) | (24,449,200) | (24,703,046) | (24,957,054) | |
| 4. | CWIP - Non-Interest Bearing | - | - | 10,000 | 20,000 | 520,000 | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $58,413,354 | 58,165,813 | 57,928,272 | 57,690,731 | 57,943,190 | 57,745,649 | 57,546,256 | 57,316,700 | 58,067,079 | 58,014,208 | 57,860,687 | 57,656,841 | 57,412,833 | |
| 6. | Average Net Investment | | 58,289,583 | 58,047,042 | 57,809,501 | 57,816,960 | 57,844,419 | 57,645,952 | 57,431,478 | 57,691,889 | 58,040,643 | 57,937,447 | 57,758,764 | 57,534,837 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $342,655 | $341,230 | $339,833 | $339,877 | $340,038 | $338,872 | $337,611 | $339,142 | $341,192 | $340,585 | $339,535 | $338,219 | $4,078,789 |
| | b. Debt Component Grossed Up For Taxes (C) | | 94,580 | 94,186 | 93,801 | 93,813 | 93,857 | 93,535 | 93,187 | 93,610 | 94,176 | 94,008 | 93,718 | 93,355 | 1,125,826 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $247,541 | $247,541 | $247,541 | $247,541 | $247,541 | $249,393 | $249,556 | $249,621 | $252,871 | $253,521 | $253,846 | $254,008 | $3,000,521 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 684,776 | 682,957 | 681,175 | 681,231 | 681,436 | 681,800 | 680,354 | 682,373 | 688,239 | 688,114 | 687,099 | 685,582 | 8,205,136 |
| | a. Recoverable Costs Allocated to Energy | | 684,776 | 682,957 | 681,175 | 681,231 | 681,436 | 681,800 | 680,354 | 682,373 | 688,239 | 688,114 | 687,099 | 685,582 | 8,205,136 |
| | b. Recoverable Costs 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) | | 684,776 | 682,957 | 681,175 | 681,231 | 681,436 | 681,800 | 680,354 | 682,373 | 688,239 | 688,114 | 687,099 | 685,582 | 8,205,136 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $684,776 | $682,957 | $681,175 | $681,231 | $681,436 | $681,800 | $680,354 | $682,373 | $688,239 | $688,114 | $687,099 | $685,582 | $8,205,136 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 311.53 ($21,689,422), 312.53 ($44,164,828), 315.53 ($13,690,954), and 316.53 ($824,684).
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% 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



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 20 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected January | Projected February | Projected March | Projected April | Projected May | Projected June | Projected July | Projected August | Projected September | Projected October | Projected November | Projected December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | $63,828,803 | $63,828,803 | $63,828,803 | $63,828,803 | $63,828,803 | $63,828,803 | $63,828,803 | $63,828,803 | $63,828,803 | $63,828,803 | $63,828,803 | $63,828,803 | $63,828,803 | |
| 3. | Less: Accumulated Depreciation | (18,032,411) | (18,215,515) | (18,398,619) | (18,581,723) | (18,764,827) | (18,947,931) | (19,131,035) | (19,314,139) | (19,497,243) | (19,680,347) | (19,863,451) | (20,046,555) | (20,229,659) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $45,796,392 | 45,613,288 | 45,430,184 | 45,247,080 | 45,063,976 | 44,880,872 | 44,697,768 | 44,514,664 | 44,331,560 | 44,148,456 | 43,965,352 | 43,782,248 | 43,599,144 | |
| 6. | Average Net Investment | | 45,704,840 | 45,521,736 | 45,338,632 | 45,155,528 | 44,972,424 | 44,789,320 | 44,606,216 | 44,423,112 | 44,240,008 | 44,056,904 | 43,873,800 | 43,690,696 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $268,676 | $267,600 | $266,523 | $265,447 | $264,370 | $263,294 | $262,218 | $261,141 | $260,065 | $258,989 | $257,912 | $256,836 | $3,153,071 |
| | b. Debt Component Grossed Up For Taxes (C) | | 74,160 | 73,863 | 73,566 | 73,269 | 72,972 | 72,674 | 72,377 | 72,080 | 71,783 | 71,486 | 71,189 | 70,892 | 870,311 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $183,104 | $183,104 | $183,104 | $183,104 | $183,104 | $183,104 | $183,104 | $183,104 | $183,104 | $183,104 | $183,104 | $183,104 | $2,197,248 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 525,940 | 524,567 | 523,193 | 521,820 | 520,446 | 519,072 | 517,699 | 516,325 | 514,952 | 513,579 | 512,205 | 510,832 | 6,220,630 |
| | a. Recoverable Costs Allocated to Energy | | 525,940 | 524,567 | 523,193 | 521,820 | 520,446 | 519,072 | 517,699 | 516,325 | 514,952 | 513,579 | 512,205 | 510,832 | 6,220,630 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 525,940 | 524,567 | 523,193 | 521,820 | 520,446 | 519,072 | 517,699 | 516,325 | 514,952 | 513,579 | 512,205 | 510,832 | 6,220,630 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $525,940 | $524,567 | $523,193 | $521,820 | $520,446 | $519,072 | $517,699 | $516,325 | $514,952 | $513,579 | $512,205 | $510,832 | $6,220,630 |

**Notes:**

(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($35,086,425), 315.54 ($11,197,193), and 316.54 ($687,934).
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 2.4%, 3.8%. 3.9%, and 3.3%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4,PAGE 21 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (3,369,246) | (3,420,555) | (3,471,864) | (3,523,173) | (3,574,482) | (3,625,791) | (3,677,100) | (3,728,409) | (3,779,718) | (3,831,027) | (3,882,336) | (3,933,645) | (3,984,954) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $20,967,461 | 20,916,152 | 20,864,843 | 20,813,534 | 20,762,225 | 20,710,916 | 20,659,607 | 20,608,298 | 20,556,989 | 20,505,680 | 20,454,371 | 20,403,062 | 20,351,753 | |
| 6. | Average Net Investment | | 20,941,807 | 20,890,498 | 20,839,189 | 20,787,880 | 20,736,571 | 20,685,262 | 20,633,953 | 20,582,644 | 20,531,335 | 20,480,026 | 20,428,717 | 20,377,408 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $123,106 | $122,805 | $122,503 | $122,202 | $121,900 | $121,598 | $121,297 | $120,995 | $120,693 | $120,392 | $120,090 | $119,789 | $1,457,370 |
| | b. Debt Component Grossed Up For Taxes (C) | | 33,980 | 33,897 | 33,813 | 33,730 | 33,647 | 33,564 | 33,480 | 33,397 | 33,314 | 33,231 | 33,147 | 33,064 | 402,264 |
| 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) | | 208,395 | 208,011 | 207,625 | 207,241 | 206,856 | 206,471 | 206,086 | 205,701 | 205,316 | 204,932 | 204,546 | 204,162 | 2,475,342 |
| | a. Recoverable Costs Allocated to Energy | | 208,395 | 208,011 | 207,625 | 207,241 | 206,856 | 206,471 | 206,086 | 205,701 | 205,316 | 204,932 | 204,546 | 204,162 | 2,475,342 |
| | b. Recoverable Costs 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) | | 208,395 | 208,011 | 207,625 | 207,241 | 206,856 | 206,471 | 206,086 | 205,701 | 205,316 | 204,932 | 204,546 | 204,162 | 2,475,342 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $208,395 | $208,011 | $207,625 | $207,241 | $206,856 | $206,471 | $206,086 | $205,701 | $205,316 | $204,932 | $204,546 | $204,162 | $2,475,342 |

**Notes:**
(A) Applicable depreciable base for Big Bend; account 312.45 ($22,880,499) and 312.44 ($1,456,209).
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% x 1/12.
(D) Applicable depreciation rate is 2.5% and 3.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11



DOCKET NO. 150007-EI
ECRC 2016 PROJECTION, FORM 42-4P
EXHIBIT NO. ____ (PAR-3), DOCUMENT NO. 4, PAGE 22 OF 25

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Air Toxics Standards (MATS)
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected January | Projected February | Projected March | Projected April | Projected May | Projected June | Projected July | Projected August | Projected September | Projected October | Projected November | Projected December | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other - AFUDC (excl from CWIP) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $8,713,288 | $8,713,288 | $8,713,288 | $8,713,288 | $8,713,288 | $8,713,288 | $8,713,288 | $8,713,288 | $8,713,288 | $8,713,288 | $8,713,288 | $8,713,288 | $8,713,288 | |
| 3. | Less: Accumulated Depreciation | (629,778) | (651,790) | (673,802) | (695,814) | (717,826) | (739,838) | (761,850) | (783,862) | (805,874) | (827,886) | (849,898) | (871,910) | (893,922) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $8,083,510 | 8,061,498 | 8,039,486 | 8,017,474 | 7,995,462 | 7,973,450 | 7,951,438 | 7,929,426 | 7,907,414 | 7,885,402 | 7,863,390 | 7,841,378 | 7,819,366 | |
| 6. | Average Net Investment | | 8,072,504 | 8,050,492 | 8,028,480 | 8,006,468 | 7,984,456 | 7,962,444 | 7,940,432 | 7,918,420 | 7,896,408 | 7,874,396 | 7,852,384 | 7,830,372 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $47,454 | $47,325 | $47,195 | $47,066 | $46,937 | $46,807 | $46,678 | $46,548 | $46,419 | $46,290 | $46,160 | $46,031 | $560,910 |
| | b. Debt Component Grossed Up For Taxes (C) | | 13,098 | 13,063 | 13,027 | 12,991 | 12,955 | 12,920 | 12,884 | 12,848 | 12,813 | 12,777 | 12,741 | 12,705 | 154,822 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | $22,012 | $22,012 | $22,012 | $22,012 | $22,012 | $22,012 | $22,012 | $22,012 | $22,012 | $22,012 | $22,012 | $22,012 | $264,144 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 82,564 | 82,400 | 82,234 | 82,069 | 81,904 | 81,739 | 81,574 | 81,408 | 81,244 | 81,079 | 80,913 | 80,748 | 979,876 |
| | a. Recoverable Costs Allocated to Energy | | 82,564 | 82,400 | 82,234 | 82,069 | 81,904 | 81,739 | 81,574 | 81,408 | 81,244 | 81,079 | 80,913 | 80,748 | 979,876 |
| | b. Recoverable Costs 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) | | 82,564 | 82,400 | 82,234 | 82,069 | 81,904 | 81,739 | 81,574 | 81,408 | 81,244 | 81,079 | 80,913 | 80,748 | 979,876 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $82,564 | $82,400 | $82,234 | $82,069 | $81,904 | $81,739 | $81,574 | $81,408 | $81,244 | $81,079 | $80,913 | $80,748 | $979,876 |

**Notes:**

(A) Applicable depreciable base for Big Bend and Polk; accounts 315.43 ($40,000), 315.44 ($40,000), 312.44 ($3,426,581), 341.80($26,150), 315.40 ($1,226,949), 315.41($138,853), 315.42($138,853), 312.45 ($2,262,901), 312.46 ($1,242,315), 315.45 ($40,217) and 315.46 ($75,022), 311.40 ($13,216), and 345.81 ($42,232)

(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).

(C) Line 6 x 1.9471% x 1/12.

(D) Applicable depreciation rate is 3.6%, 3.2%, 3.0%, 2.2%, 3.7%, 3.5%, 3.3%, 2.5%, 3.3%, 3.1%, 3.5%, 2.9% and 3.3%

(E) Line 9a x Line 10

(F) Line 9b x Line 11



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**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

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 | (35,207) | (35,145) | (35,098) | (35,055) | (35,014) | (34,966) | (34,908) | (34,849) | (34,788) | (34,728) | (34,666) | (34,616) | (34,563) | |
| 3. | Total Working Capital Balance | ($35,207) | (35,145) | (35,098) | (35,055) | (35,014) | (34,966) | (34,908) | (34,849) | (34,788) | (34,728) | (34,666) | (34,616) | (34,563) | |
| 4. | Average Net Working Capital Balance | | ($35,176) | ($35,122) | ($35,077) | ($35,034) | ($34,990) | ($34,937) | ($34,879) | ($34,819) | ($34,758) | ($34,697) | ($34,641) | ($34,589) | |
| 5. | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (A) | | (207) | (206) | (206) | (206) | (206) | (205) | (205) | (205) | (204) | (204) | (204) | (203) | (2,461) |
| | b. Debt Component Grossed Up For Taxes (B) | | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (56) | (56) | (56) | (56) | (56) | (679) |
| 6. | Total Return Component | | (264) | (263) | (263) | (263) | (263) | (262) | (262) | (261) | (260) | (260) | (260) | (259) | (3,140) |
| 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 | | 728 | 743 | 757 | 739 | 732 | 732 | 721 | 728 | 730 | 728 | 720 | 747 | 8,805 |
| 8. | Net Expenses (D) | | 728 | 743 | 757 | 739 | 732 | 732 | 721 | 728 | 730 | 728 | 720 | 747 | 8,805 |
| 9. | Total System Recoverable Expenses (Lines 6 + 8) | | 464 | 480 | 494 | 476 | 469 | 470 | 459 | 467 | 470 | 468 | 460 | 488 | 5,665 |
| | a. Recoverable Costs Allocated to Energy | | 464 | 480 | 494 | 476 | 469 | 470 | 459 | 467 | 470 | 468 | 460 | 488 | 5,665 |
| | b. Recoverable Costs 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) | | 464 | 480 | 494 | 476 | 469 | 470 | 459 | 467 | 470 | 468 | 460 | 488 | 5,665 |
| 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) | | $464 | $480 | $494 | $476 | $469 | $470 | $459 | $467 | $470 | $468 | $460 | $488 | $5,665 |

**Notes:**

(A) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(B) Line 6 x 1.9471% 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 2016 to December 2016**

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) | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | 21,258,302 | |
| 3. | Less: Accumulated Depreciation | (664,819) | (716,193) | (767,567) | (818,941) | (870,315) | (921,689) | (973,063) | (1,024,437) | (1,075,811) | (1,127,185) | (1,178,559) | (1,229,933) | (1,281,307) | |
| 4. | CWIP - Non-Interest Bearing | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $20,593,483 | 20,542,109 | 20,490,735 | 20,439,361 | 20,387,987 | 20,336,613 | 20,285,239 | 20,233,865 | 20,182,491 | 20,131,117 | 20,079,743 | 20,028,369 | 19,976,995 | |
| 6. | Average Net Investment | | 20,567,796 | 20,516,422 | 20,465,048 | 20,413,674 | 20,362,300 | 20,310,926 | 20,259,552 | 20,208,178 | 20,156,804 | 20,105,430 | 20,054,056 | 20,002,682 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | $120,908 | $120,606 | $120,304 | $120,002 | $119,700 | $119,398 | $119,096 | $118,794 | $118,492 | $118,190 | $117,888 | $117,586 | $1,430,964 |
| | b. Debt Component Grossed Up For Taxes (C) | | 33,373 | 33,290 | 33,206 | 33,123 | 33,040 | 32,956 | 32,873 | 32,789 | 32,706 | 32,623 | 32,539 | 32,456 | 394,974 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 51,374 | 51,374 | 51,374 | 51,374 | 51,374 | 51,374 | 51,374 | 51,374 | 51,374 | 51,374 | 51,374 | 51,374 | $616,488 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 205,655 | 205,270 | 204,884 | 204,499 | 204,114 | 203,728 | 203,343 | 202,957 | 202,572 | 202,187 | 201,801 | 201,416 | 2,442,426 |
| | a. Recoverable Costs Allocated to Energy | | 205,655 | 205,270 | 204,884 | 204,499 | 204,114 | 203,728 | 203,343 | 202,957 | 202,572 | 202,187 | 201,801 | 201,416 | 2,442,426 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 11. | Demand Jurisdictional Factor | | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | 1.0000000 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 205,655 | 205,270 | 204,884 | 204,499 | 204,114 | 203,728 | 203,343 | 202,957 | 202,572 | 202,187 | 201,801 | 201,416 | 2,442,426 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $205,655 | $205,270 | $204,884 | $204,499 | $204,114 | $203,728 | $203,343 | $202,957 | $202,572 | $202,187 | $201,801 | $201,416 | $2,442,426 |

**Notes:**
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 7.0542% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200).
(C) Line 6 x 1.9471% 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**
**January 2016 through December 2016**
**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 2015 through December 2015, is $1,164,812 compared to the original projection of $1,163,997, resulting in an insignificant variance.

The actual/estimated O&M expense for the period January 2015 through December 2015 is $5,607,172 compared to the original projection of $6,245,680, resulting in a variance of 10.2 percent. This variance is due to a forced outage at Big Bend Unit 3 that resulted in a decrease in chemical consumption.

Progress Summary: This project was approved by the Commission in Docket No. 960688-EI, Order No. PSC-96-1048-FOF-EI, issued August 14, 1996. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016, is expected to be $1,139,394.

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $5,844,840.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2016 through December 2016**
**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 2015 through December 2015 is $313,558 compared to the original projection of $314,305, resulting in an insignificant variance.

The actual/estimated O&M expense for this project for the period January 2015 through December 2015 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 960688-EI, Order No. PSC-96-1048-FOF-EI, issued August 14, 1996. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $295,317.

There are no estimated O&M costs projected for the period of January 2016 through December 2016.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2016 through December 2016**
**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 2015 through December 2015 is $63,363 compared to the original projection of $63,588, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 960688-EI, Order No. PSC-96-1048-FOF-EI, issued August 14, 1996. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $60,631.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2016 through December 2016**
**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 2015 through December 2015 is $100,325 compared to the original projection of $100,625, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 980007-EI, Order No. PSC-98-1764-FOF-EI, issued December 31, 1998. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $95,268.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2016 through December 2016**
**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 2015 through December 2015 is $72,408 compared to the original projection of $72,634, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 980007-EI, Order No. PSC-98-1764-FOF-EI, issued December 31, 1998. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $68,888

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2016 through December 2016**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Units 1 & 2 FGD

**Project Description:**

The Big Bend Units 1 & 2 FGD system consists of equipment capable of removing $SO_2$ from the flue gas generated by the combustion of coal. The FGD was installed in order to comply with Phase II of the CAAA. Compliance with Phase II 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 2015 through December 2015 is $7,284,957 compared to the original projection of $7,503,897, resulting in an insignificant variance.

The actual/estimated O&M expense for the period January 2015 through December 2015 is $8,789,921 compared to the original estimate of $10,189,162, resulting in a variance of 13.7 percent. This variance is due to a forced outage on Big Bend Unit 2, resulting in a decrease in chemical consumption.

Progress Summary: This project was approved by the Commission in Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is expected to be $7,132,213.

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $9,795,402.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2016 through December 2016**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Section 114 Mercury Testing Platform

**Project Description:**

The Mercury Emissions Information Collection Effort is mandated by the EPA. The EPA asserts that Section 114 of the CAAA grants to the EPA the authority to request the collection of information necessary for it to study whether it is appropriate and necessary to develop performance or 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 2015 through December 2015, is $10,535 compared to the original projection of $10,579, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 990976-EI, Order No. PSC-99-2103-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 2016 through December 2016 is expected to be $10,174.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
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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 being performed.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2015 through December 2015 is $1,839,605 compared to the original projection of $1,847,903, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 000685-EI, Order No. PSC-00-1906-PAA-EI, issued October 18, 2000. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is expected to be $1,782,205.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
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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 experience O&M and capital expenditures.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2015 through December 2015 is $1,846,455 compared to the original projection of $1,792,308, resulting in an insignificant variance. .

The actual/estimated O&M expense the period January 2015 through December 2015 is $904,608 compared to the original projection of $840,000 resulting in a variance of 7.7 percent. This variance is due to an increase in price for routine monthly inspections.

Progress Summary: This project was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is expected to be $2,299,671.

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $924,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
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**Project Title:** Big Bend $NO_x$ Emissions Reduction

**Project Description:**

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to spend up to $3 million with the goal to reduce $NO_x$ emissions at Big Bend Station. By 2002, the Consent Decree required the company to achieve at least a 30 percent reduction beyond 1998 $NO_x$ emission levels for Big Bend Units 1 and 2 and at least a 15 percent reduction in $NO_x$ emissions from Big Bend Unit 3. Tampa Electric identified and completed projects that were the first steps to decrease $NO_x$ emissions in these units such as burner and windbox modifications and the installation of a neural network system on each of the Big Bend units.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2015 through December 2015 is $608,606 compared to the original projection of $611,733, resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2015 through December 2015 is $109,491 compared to the original projection of $120,000, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is expected to be $594,430.

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $130,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
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**Project Title:** Big Bend Fuel Oil Tank No. 1 Upgrade

**Project Description:**

The Big Bend Fuel Oil Tank No. 1 Upgrade is a 500,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an 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 2015 through December 2015 is $41,016 compared to the original projection of $41,168, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 980007-EI, Order No. PSC-98-0408-FOF-EI, issued March 18, 1998. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $39,333.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
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**Project Title:** Big Bend Fuel Oil Tank No. 2 Upgrade

**Project Description:**

The Big Bend Fuel Oil Tank No. 2 Upgrade 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 2015 through December 2015 is $67,457 compared to the original projection of $67,712, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 980007-EI, Order No. PSC-98-0408-FOF-EI, issued March 18, 1998. The project is complete and in-service

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $64,693.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
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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 2015 through December 2015 is ($3,214) compared to the original projection of ($3,226), resulting in an insignificant variance.

The actual/estimated O&M for the period January 2015 through December 2015 is $15,198 compared to the original projection of $26,128, resulting in a variance of 41.8 percent. The variance is driven by less cogeneration purchases than expected and the application of a lower emission allowance rate than originally projected.

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 2016 through December 2016 is projected to be ($3,140).

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $8,805.

**Tampa Electric Company**
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**Project Title:** National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees

**Project Description:**

Chapter 62-4.052, Florida Administrative Code ("F. A. C."), implements the annual regulatory program and surveillance fees for wastewater permits. These fees are in addition to the application fees described in Rule 62-4.050, F. A. C. Tampa Electric's Big Bend, Polk Power and Bayside Stations are affected by this rule.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2015 through December 2015 is $34,500 and did not vary from the original projection.

Progress Summary: NPDES Surveillance fees are paid annually for the prior year.

Projections: Estimated O&M costs for the period January 2016 through December 2016 are projected to be $34,500.

**Tampa Electric Company**
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**Project Title:** Gannon Thermal Discharge Study

**Project Description:**

This project was a direct requirement from the FDEP in conjunction with the renewal of Tampa Electric's Industrial Wastewater Facility Permit under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code, which constitute authorization for the company's Gannon Station facility to discharge to waters of the State under the NPDES. The FDEP permit is Permit No. FL0000809. Specifically, Tampa Electric was required to perform a 316(a) determination for Gannon Station to ensure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife 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: The actual/estimated O&M expense for the period January 2015 through December 2015 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 010593-EI, Order No. PSC-01-1847-PAA-EI on September 4, 2001. The project is complete and in-service.

Projections: There are no estimated O&M costs projected for the period of January 2016 through December 2016.

**Tampa Electric Company**
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**Project Title:** Polk $NO_x$ Emissions Reduction

**Project Description:**

This project was designed to meet a lower $NO_x$ emissions limit established by the FDEP for Polk Unit 1 by July 1, 2005. The lower limit of 15 parts per million by volume dry basis at 15 percent $O_2$ is specified in FDEP Permit No. PSD-FL-194F issued February 5, 2002. The project consisted of two phases: 1) the humidification of syngas through the installation of a syngas saturator; and 2) the modification of controls and the installation of additional guide vanes to the diluent nitrogen compressor.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2015 through December 2015 is $139,869 compared to the original projection of $140,423, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2015 through December 2015 is $10,321 compared to the original projection of $20,000, which represents a variance of 48.4 percent. This variance is due to an extended outage for Polk Unit 1, resulting in minimal maintenance associated with this project.

Progress Summary: This project was approved by the Commission in Docket No. 020726-EI, Order No. PSC-02-1445-PAA-EI on October 21, 2002. The project is complete and in-service.

Project Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $134,519.

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $20,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
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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 2015 through December 2015 is $150,590, compared to the original projection of $145,000, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. As an O&M project, expenses are ongoing annually.

Projections: Estimated O&M costs for the period January 2016 through December 2016 are projected to be $204,000.

**Tampa Electric Company**
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**Project Title:** Big Bend Unit 4 Separated Overfire Air ("SOFA")

**Project Description:**

This project is necessary to assist in achieving the $NO_x$ emissions limit established by the FDEP Consent Final Judgment and the EPA Consent Decree for Big Bend Unit 4. A SOFA system stages secondary combustion air to prevent $NO_x$ formation that would otherwise require removal by post-combustion technology. In-furnace combustion control through a SOFA system is the most cost-effective means to reduce $NO_x$ emissions prior to the application of these technologies. Costs associated with the SOFA system entailed capital expenditures for equipment installation and subsequent annual maintenance.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2015 through December 2015 is $243,592 compared to the original projection of $244,659, resulting in an insignificant variance.

The actual/estimated O&M expense for this project for the period January 2015 through December 2015 is $24,000, compared to the original projection of $48,000, resulting in a variance of 50 percent. The actual/estimated maintenance cost associated with this project is less than the work that was originally projected because less work was needed than originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 030226-EI, Order No. PSC-03-0684-PAA-EI, issued June 6, 2003. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $235,586.

Estimated O&M costs for the period of January 2016 through December 2016 are projected to be $42,000.

**Tampa Electric Company**
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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 2015 through 2016. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which necessitated the installation of cost-effective SCR technology on the generating units to meet $NO_x$ emissions requirements. Therefore, 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 2015 through December 2015 is $170,018 compared to the original projection of $170,683, resulting in an insignificant variance.

The actual/estimated O&M expense for this project for the period January 2015 through December 2015 is $128,649, compared to the original projection of $138,000, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $163,398.

Estimated O&M costs for the period of January 2016 through December 2016 is are projected to be $42,000.

**Tampa Electric Company**
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**Project Title:** Big Bend Unit 2 Pre-SCR

**Project Description:**

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of $NO_x$ emissions at Big Bend Station on a per unit basis at prescribed times from 2015 through 2016. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which necessitated the installation of cost-effective SCR technology on the generating units to meet $NO_x$ emissions requirements. Therefore, 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 2015 through December 2015 is $161,262 compared to the original projection of $161,919, resulting in an insignificant variance.

The actual/estimated O&M expense for this project for the period January 2015 through December 2015 is $52,505, compared to the original projection of $48,000, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $155,318.

Estimated O&M costs for the period of January 2016 through December 2016 is are projected to be $42,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
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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 2015 through 2016. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which necessitated the installation of cost-effective SCR technology on the generating units to meet $NO_x$ emissions requirements. Therefore, 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 2015 through December 2015 is $286,881 compared to the original projection of $288,104, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2015 through December 2015 is $24,000 compared to the original projection of $48,000, resulting in a variance of 50 percent. The actual/estimated maintenance cost associated with this project is less than the work that was originally projected as less work was needed.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $277,035.

Estimated O&M costs for the period of January 2016 through December 2016 is are projected to be $42,000

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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 H. L. Culbreath Bayside Power and the Big Bend Power 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 2015 through December 2015 is $370,652 compared to the original projection of $960,000 resulting, resulting in a variance of 61.4 percent. This variance is due to ongoing negotiations regarding the use of existing 316(b) data. As a result, there is a delay in the timing of the work to be done to meet the requirements of the May 2014 rule.

Progress Summary: This project was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005. The project is complete and in-service.

Projections: Estimated O&M costs for the period January 2016 through December 2016 are projected to be $960,000.

**Tampa Electric Company**
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**Project Title:** Big Bend Unit 1 SCR

**Project Description:**

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of $NO_x$ emissions at Big Bend Station on a per unit basis at prescribed times from 2015 through 2016. Based on a comprehensive study, Tampa Electric declared the future fuel for Big Bend Station to be coal, which necessitated the installation of cost-effective SCR technology on the generating units to meet $NO_x$ emissions requirements.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2015 through December 2015 is $9,703,343 compared to the original projection of $9,741,516, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2015 through December 2015 is $2,347,505 compared to the original projection of $2,164,529, resulting in a variance of 8.5 percent. This variance is due to the actual/estimated consumption of ammonia being greater than originally projected. Greater ammonia consumption is expected because Big Bend Unit 1 is expected to operate for a greater number of hours than originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $9,329,944.

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $2,025,000.

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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 2015 through 2016. Based on a comprehensive study, Tampa Electric declared the future fuel for Big Bend Station to be coal, which necessitated the installation of cost-effective SCR technology on the generating units to meet $NO_x$ emissions requirements.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2015 through December 2015 is $10,278,852 compared to the original projection of $10,220,155, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2015 through December 2015 is $1,878,619 compared to the original projection of $2,499,555, resulting in a variance of 24.8 percent. This variance is due to an extended outage that decreased the amount of ammonia consumed.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $9,982,742.

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $1,613,000.

**Tampa Electric Company**
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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 2015 through 2016. Based on a comprehensive study, Tampa Electric declared the future fuel for Big Bend Station to be coal which necessitated the installation of cost-effective SCR technology on the generating units to meet $NO_x$ emissions requirements.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2015 through December 2015 is $8,397,829 compared to the original projection of $8,546,448, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2015 through December 2015 is $2,230,792 compared to the original projection of $2,023,711, resulting in a variance of 10.2 percent. Greater ammonia consumption is expected because Big Bend Unit 3 is expected to operate for a greater number of hours than originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $8,205,136.

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $2,032,000.

**Tampa Electric Company**
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**Project Title:** Big Bend Unit 4 SCR

**Project Description:**

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of $NO_x$ emissions at Big Bend Station on a per unit basis at prescribed times from 2015 through 2016. Based on a comprehensive study, Tampa Electric declared the future fuel for Big Bend Station to be coal which necessitated the installation of cost-effective SCR technology on the generating units to meet $NO_x$ emissions requirements.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2015 through December 2015 is $6,392,540 compared to the original projection of $6,404,385, resulting in an insignificant variance.

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The actual/estimated O&M for the period January 2015 through December 2015 is $1,172,664 compared to the original projection of $1,111,949, resulting in a variance of 5.5 percent. The actual/estimated consumption of ammonia is expected to be greater than originally projected because of Big Bend Unit 4 is expected to operate for a greater number of hours than originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-0986-PAA-EI, issued October 11, 2004. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $6,220,630.

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $2,070,000.

**Tampa Electric Company**
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**Project Title:** Arsenic Groundwater Standard Program

**Project Description:**
The Arsenic Groundwater Standard Program that is required by the Environmental Protection Agency and the Department of Environmental Protection became effective January 1, 2005. It requires regulated entities of the State of Florida to monitor the drinking water and groundwater Maximum Contaminant Level ("MCL") for arsenic under the federal rule known as the Safe Drinking Water Act.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated O&M for the period January 2015 through December 2015 is $57,560 compared to the original projection of $300,000, resulting in a variance of 80.8 percent. This variance is due to ongoing negotiations with the FDEP regarding ground water treatment at Bayside Station.

Progress Summary: This project was approved by the Commission in Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2006. The project is complete and in-service.

Projections: Estimated O&M costs for the period January 2016 through December 2016 are projected to be $25,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2016 through December 2016**
**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 2015 through December 2015 is $2,543,372 compared to the original projection of $2,555,739, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006. The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $2,475,342.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2016 through December 2016**
**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 2015 through December 2015 is $981,575 compared to the original projection of $971,990 resulting in an insignificant variance.

The actual/estimated O&M for the period January 2015 through December 2015 is $183,392 compared to the original projection of $230,000, resulting in a variance of 20.3 percent. This variance is due to Tampa Electric using internal labor resources for stack testing. The original projection included costs for contract labor to complete testing.

Progress Summary: This project was approved by the Commission in Docket No. 120302-EI, Order No. PSC-13-0191-PAA-EI, issued May 6, 2013. This project, in total, is expected to be placed in-service by April 2015.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $979,876.

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $230,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2016 through December 2016**
**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 2015 through December 2015 is $97,411 compared to the original projection of $90,000, resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PAA-EI, issued March 22, 2010. The project is complete and in-service.

Projections: Estimated O&M costs for the period January 2016 through December 2016 are projected to be $90,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2016 through December 2016**
**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 is no longer sufficient to hold the entire gypsum inventory. As such, Tampa Electric needed an additional storage facility that will allow the company to continue managing its gypsum inventory while continuing its marketing efforts to sell the gypsum. The new storage facility will cover approximately 27 acres and will hold approximately 870,000 tons of gypsum.

**Project Accomplishments:**

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2015 through December 2015 is $2,503,343 compared to the original projection of $2,807,047, resulting in a variance of 10.8 percent. The depreciation rate used to project depreciation amounts for this project, in the original projection, was inaccurate. The company assigned the correct depreciation rate, reducing the amount of cost recovery for this project for the actual/estimated period.

The actual/estimated O&M for the period January 2015 through December 2015 is $1,072,105 compared to the original projection of $1,284,000, resulting in a variance of 16.5 percent. This variance is due to extended use of the old storage facility, resulting in less utilization that originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 110262-EI, Order No. PSC-12-0493-PAA-EI, issued September 26, 2012. The project was placed in-service in November 2014.

Projections: Estimated depreciation plus return for the period January 2016 through December 2016 is projected to be $2,442,426.

Estimated O&M costs for the period January 2016 through December 2016 are projected to be $900,000.

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
**January 2016 to December 2016**

| 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 | 53.76% | 8,914,762 | 8,914,762 | 1,893 | 1.07778 | 1.05339 | 9,390,726 | 2,040 | 47.58% | 56.84% | 56.13% |
| GS, CS | 58.00% | 1,014,240 | 1,014,240 | 200 | 1.07778 | 1.05338 | 1,068,375 | 216 | 5.41% | 6.02% | 5.97% |
| GSD, SBF | 79.07% | 7,907,036 | 7,893,311 | 1,142 | 1.07348 | 1.04958 | 8,299,087 | 1,226 | 42.04% | 34.16% | 34.77% |
| IS | 83.49% | 739,587 | 726,559 | 101 | 1.02887 | 1.01847 | 753,250 | 104 | 3.82% | 2.90% | 2.97% |
| LS1 | 864.97% | 214,899 | 214,899 | 3 | 1.07778 | 1.05339 | 226,373 | 3 | 1.15% | 0.08% | 0.16% |
| TOTAL * | | 18,790,524 | 18,763,771 | 3,339 | | | 19,737,811 | 3,589 | 100.00% | 100.00% | 100.00% |

Notes:
(1) Average 12 CP load factor based on 2016 projected calendar data
(2) Projected MWh sales for the period January 2016 to December 2016
(3) Effective sales at secondary level for the period January 2016 to December 2016
(4) Column 2 / (Column 1 x 8760)
(5) Based on 2014 projected demand losses
(6) Based on 2014 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



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ECRC 2016 PROJECTION, FORM 42-6P
EXHIBIT NO. ____ (PAR-3) , DOCUMENT NO. 6

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
**January 2016 to December 2016**

| Rate Class | (1) Percentage of MWh Sales at Generation (%) | (2) 12 CP & 1/13 Allocation Factor (%) | (3) Energy-Related Costs ($) | (4) Demand-Related Costs ($) | (5) Total Environmental Costs ($) | (6) Projected Sales at Meter (MWh) | (7) Effective Sales at Secondary Level (MWh) | **(8) Environmental Cost Recovery Factors (¢/kWh)** |
|---|---|---|---|---|---|---|---|---|
| RS | 47.58% | 56.13% | 37,849,730 | 642,315 | 38,492,045 | 8,914,762 | 8,914,762 | **0.432** |
| GS, CS | 5.41% | 5.97% | 4,303,637 | 68,317 | 4,371,954 | 1,014,240 | 1,014,240 | **0.431** |
| GSD, SBF | 42.04% | 34.77% | 33,442,678 | 397,885 | 33,840,563 | 7,907,036 | 7,893,311 | |
| Secondary | | | | | | | | **0.429** |
| Primary | | | | | | | | **0.424** |
| Transmission | | | | | | | | **0.420** |
| IS | 3.82% | 2.97% | 3,038,797 | 33,987 | 3,072,784 | 739,587 | 726,559 | |
| Secondary | | | | | | | | **0.423** |
| Primary | | | | | | | | **0.419** |
| Transmission | | | | | | | | **0.414** |
| LS1 | 1.15% | 0.16% | 914,821 | 1,831 | 916,652 | 214,899 | 214,899 | **0.427** |
| TOTAL * | 100.00% | 100.00% | 79,549,663 | 1,144,334 | 80,693,997 | 18,790,524 | 18,763,771 | **0.430** |

* 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



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ECRC 2016 PROJECTION, FORM 42-7P
EXHIBIT NO. ____ (PAR-3) , DOCUMENT NO. 7

Form 42 - 8P

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 to December 2016**

**Calculation of Revenue Requirement Rate of Return**
(In Dollars)

| | (1) Jurisdictional Rate Base *Actual May 2015* Capital Structure ($000) | (2) Ratio % | (3) Cost Rate % | (4) Weighted Cost Rate % |
|---|---|---|---|---|
| Long Term Debt | $ 1,500,445 | 35.24% | 5.33% | 1.8783% |
| Short Term Debt | 25,918 | 0.61% | 0.71% | 0.0043% |
| Preferred Stock | 0 | 0.00% | 0.00% | 0.0000% |
| Customer Deposits | 108,557 | 2.55% | 2.27% | 0.0579% |
| Common Equity | 1,791,818 | 42.09% | 10.25% | 4.3142% |
| Deferred ITC - Weighted Cost | 7,573 | 0.18% | 7.96% | 0.0143% |
| Accumulated Deferred Income Taxes | 823,006 | 19.33% | 0.00% | 0.0000% |
| Zero Cost ITCs | | | | |
| Total | $ 4,257,317 | 100.00% | | 6.27% |

**ITC split between Debt and Equity:**

| | | | |
|---|---|---|---|
| Long Term Debt | $ 1,500,445 | Long Term Debt | 45.22% |
| Short Term Debt | 25,918 | Short Term Debt | 0.78% |
| Equity - Preferred | 0 | Equity - Preferred | 0.00% |
| Equity - Common | 1,791,818 | Equity - Common | 54.00% |
| Total | $ 3,318,181 | Total | 100.00% |

**Deferred ITC - Weighted Cost:**

| | |
|---|---|
| Debt = .0143% * 46.00% | 0.0066% |
| Equity = .0143% * 54.00% | 0.0077% |
| Weighted Cost | 0.0143% |

**Total Equity Cost Rate:**

| | |
|---|---|
| Preferred Stock | 0.0000% |
| Common Equity | 4.3142% |
| Deferred ITC - Weighted Cost | 0.0077% |
| | 4.3219% |
| Times Tax Multiplier | 1.632200 |
| Total Equity Component | 7.0542% |

**Total Debt Cost Rate:**

| | |
|---|---|
| Long Term Debt | 1.8783% |
| Short Term Debt | 0.0043% |
| Customer Deposits | 0.0579% |
| Deferred ITC - Weighted Cost | 0.0066% |
| Total Debt Component | 1.9471% |
| | 9.0013% |

**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)

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# FEDERAL REGISTER

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Part II

## Environmental Protection Agency

40 CFR Parts 257 and 261
Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities; Final Rule

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 24
PARTY: GULF POWER COMPANY (GULF) – (DIRECT)
DESCRIPTION: J. O. Vick JOV-1

## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Parts 257 and 261

**[EPA–HQ–RCRA–2009–0640; FRL–9919–44–OSWER]**

**RIN–2050–AE81**

## Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** The Environmental Protection Agency (EPA or the Agency) is publishing a final rule to regulate the disposal of coal combustion residuals (CCR) as solid waste under subtitle D of the Resource Conservation and Recovery Act (RCRA). The available information demonstrates that the risks posed to human health and the environment by certain CCR management units warrant regulatory controls. EPA is finalizing national minimum criteria for existing and new CCR landfills and existing and new CCR surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, except in limited circumstances. It also requires the closure of any CCR landfill or CCR surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Finally, those CCR surface impoundments that do not receive CCR after the effective date of the rule, but still contain water and CCR will be subject to all applicable regulatory requirements, unless the owner or operator of the facility dewaters and installs a final cover system on these inactive units no later than three years from publication of the rule. EPA is deferring its final decision on the Bevill Regulatory Determination because of regulatory and technical uncertainties that cannot be resolved at this time.

**DATES:** This final rule is effective on October 14, 2015.

**ADDRESSES:** EPA has established three dockets for this regulatory action under Docket ID No. EPA–HQ–RCRA–2009–0640, Docket ID No. EPA–HQ–RCRA–2011–0392, and Docket ID No. EPA–HQ–RCRA–2012–0028. All documents in these dockets are available at *http://www.regulations.gov*. Although listed in the index, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) 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 hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the OSWER Docket, EPA/DC, WJC West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460. 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 OSWER Docket is 202–566–0276.

**FOR FURTHER INFORMATION CONTACT:** For questions on technical issues: Alexander Livnat, Office of Resource Conservation and Recovery, Environmental Protection Agency, 5304P; telephone number: (703) 308–7251; fax number: (703) 605–0595; email address: *livnat.alexander@epa.gov*, or Steve Souders, Office of Resource Conservation and Recovery, Environmental Protection Agency, 5304P; telephone number: (703) 308–8431; fax number: (703) 605–0595; email address: *souders.steve@epa.gov*. For questions on the regulatory impact analysis: Richard Benware, Office of Resource Conservation and Recovery, Environmental Protection Agency, 5305P; telephone number: (703) 308–0436; fax number: (703) 308–7904; email address: *benware.richard@epa.gov*. For questions on the risk assessment: Jason Mills, Office of Resource Conservation and Recovery, Environmental Protection Agency, 5305P; telephone number: (703) 305–9091; fax number: (703) 308–7904; email address: *mills.jason@epa.gov*.

For more information on this rulemaking please visit *http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/index.htm*.

**SUPPLEMENTARY INFORMATION:**

### A. Does this action apply to me?

This rule applies to all coal combustion residuals (CCR) generated by electric utilities and independent power producers that fall within the North American Industry Classification System (NAICS) code 221112 and may affect the following entities: Electric utility facilities and independent power producers that fall under the NAICS code 221112. The industry sector(s) identified above may not be exhaustive; other types of entities not listed could also be affected. The Agency's aim is to provide a guide for readers regarding those entities that potentially could be affected by this action. To determine whether your facility, company, business, organization, etc., is affected by this action, you should refer to the applicability criteria discussed in Unit VI.A. of this document If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

### B. What actions are not addressed in this rule?

This rule does not address the placement of CCR in coal mines. The U.S. Department of Interior (DOI) and, as necessary, EPA will address the management of CCR in minefills in separate regulatory action(s), consistent with the approach recommended by the National Academy of Sciences, recognizing the expertise of DOI's Office of Surface Mining Reclamation and Enforcement in this area. See Unit VI of this document for further details. This rule does not regulate practices that meet the definition of a beneficial use of CCR. Beneficial uses that occur after the effective date of the rule need to determine if they comply with the criteria contained in the definition of "beneficial use of CCRs." This rule does not affect past beneficial uses (*i.e.*, uses completed before the effective date of the rule.) See Unit VI of this document for further details on proposed clarifications of beneficial use. Furthermore, CCR from non-utility boilers burning coal are also not addressed in this final rule. EPA will decide on an appropriate action for these wastes through a separate rulemaking effort. See Unit IV of this document for further details. Finally, this rule does not apply to municipal solid waste landfills (MSWLFs) that receive CCR for disposal or use as daily cover.

### C. The Contents of This Preamble Are Listed in the Following Outline

I. Executive Summary
II. Statutory Authority
III. Background
IV. Bevill Regulatory Determination Relating to CCR From Electric Utilities and Independent Power Producers
V. Development of the Final Rule—RCRA Subtitle D Regulatory Approach

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VI. Development of the Final Rule—Technical Requirements
VII. Summary of Major Differences Between the Proposed and Final Rules
VIII. Implementation Timeframes for Minimum National Criteria and Coordination With Steam Electric ELG Rule
IX. Implementation of the Minimum Federal Criteria and State Solid Waste Management Plans
X. Risk Assessment
XI. Summary of Damage Cases
XII. Summary of Regulatory Impact Analysis
XIII. Uniquely Associated Wastes
XIV. Statutory and Executive Order Reviews

## I. Executive Summary

This rule establishes nationally applicable minimum criteria for the safe disposal of coal combustion residuals in landfills and surface impoundments. This section summarizes these criteria. Detailed discussions of the criteria and the Agency's rationale for finalizing these requirements are provided in Unit VI of this document.

### *A. What are coal combustion residuals?*

Coal combustion residuals (CCR) are generated from the combustion of coal, including solid fuels classified as anthracite, bituminous, subbituminous, and lignite, for the purpose of generating steam for the purpose of powering a generator to produce electricity or electricity and other thermal energy by electric utilities and independent power producers. CCR includes fly ash, bottom ash, boiler slag, and flue gas desulfurization materials. A description of the types of CCR can be found in the proposed rule (see 75 FR 35137).

CCR is one of the largest industrial waste streams generated in the U.S. In 2012, over 470 coal-fired electric utilities burned over 800 million tons of coal, generating approximately 110 million tons of CCR in 47 states and Puerto Rico. CCR may be generated wet or dry; however, this composition may change after generation. Some CCR is dewatered while other CCR is mixed with water to facilitate transport (*i.e.*, sluiced). CCR can be sent off-site for disposal or beneficial use or disposed in on-site landfills or surface impoundments. In 2012, approximately 40 percent of the CCR generated was beneficially used, with the remaining 60 percent disposed in surface impoundments and landfills. Of that 60 percent, approximately 80 percent was disposed in on-site disposal units. CCR disposal currently occurs at over 310 active on-site landfills, averaging over 120 acres in size with an average depth of over 40 feet, and at over 735 active on-site surface impoundments, averaging over 50 acres in size with an average depth of 20 feet.

### *B. Background*

The Agency first solicited comments on the regulation of CCR in a proposed rule published in the **Federal Register** on June 21, 2010. This proposal, under the Resource Conservation and Recovery Act (RCRA), addressed the risks from disposal of CCR generated from the combustion of coal at electric utilities and from independent power producers. Two regulatory options were proposed. Under the first option, EPA proposed to list CCR as special waste subject to regulation under subtitle C of RCRA, when destined for disposal in landfills or surface impoundments. Under this option, CCR would require "cradle-to-grave" management and would be subject to requirements for, among other things, composite liners, groundwater monitoring, structural stability requirements, corrective action, closure/post closure care and financial assurance. States would be required to adopt the rule before it went into effect and a permitting program would be established with direct federal oversight. The subtitle C option, as proposed, would also effectively result in the closure of all CCR surface impoundments.

Under the second option, EPA proposed to regulate the disposal of CCR under subtitle D of RCRA by issuing minimum national criteria. Similar to the subtitle C option, this option would require composite liners, groundwater monitoring, structural stability requirements, corrective action, and closure/post closure care. However, consistent with the available statutory authority under subtitle D, EPA proposed this option to be a self-implementing rule with no direct federal oversight, with an effective date six months after publication in the **Federal Register**. This option required all unlined surface impoundments to either retrofit to a composite liner or close within five years.

After reviewing all the comments and additional data received, EPA is promulgating this final rule to regulate the disposal of CCR as solid waste under subtitle D of RCRA. This rule addresses the risks from structural failures of CCR surface impoundments, groundwater contamination from the improper management of CCR in landfills and surface impoundments and fugitive dust emissions. The rule has also been designed to provide electric utilities and independent power producers generating CCR with a practical approach for implementation of the requirements and has established implementation timelines that take into account, among other things, other upcoming regulatory actions affecting electric utilities and site specific practical realities. In order to ease implementation of the regulatory requirements for CCR units with state programs, EPA is also providing the opportunity for states to secure approval of its CCR program through the State Solid Waste Management Plan ("SWMP"). EPA strongly recommends that states take advantage of this process by revising their SWMPs to address the issuance of the revised federal requirements in this final rule, and to submit revisions of these plans to EPA for review. EPA would then review and approve the revised SWMPs provided they demonstrate that the minimum federal requirements in this final rule will be met. In this way, EPA's approval of a revised SWMP signals EPA's opinion that the state SWMP meets the minimum federal criteria.

### *C. What types of CCR units are covered by this rule?*

The final rule applies to owners and operators of new and existing landfills and new and existing surface impoundments, including all lateral expansions of landfills and surface impoundments that dispose or otherwise engage in solid waste management of CCR generated from the combustion of coal at electric utilities and independent power producers. The requirements of the rule also apply to CCR units located off-site of the electric utilities' or independent power producers' facilities that receive CCR for disposal. In addition, the rule applies to certain inactive CCR surface impoundments (*i.e.*, units not receiving CCR after the effective date of the rule) at active electric utilities' or independent power producers' facilities, regardless of the fuel currently used at the facility to produce electricity (*e.g.* coal, natural gas, oil), if the CCR unit still contains CCR and liquids.

The requirements do not apply to: (1) CCR landfills that ceased receiving CCR prior to the effective date of the rule; (2) CCR units at facilities that have ceased producing electricity (or electricity and other thermal energy) prior to the effective date of the rule; (3) CCR generated at facilities that are not part of an electric utility or independent power producer, such as manufacturing facilities, universities, and hospitals; (4) fly ash, bottom ash, boiler slag, and flue gas desulfurization materials, generated primarily from the combustion of fuels (including other fossil fuels) other than coal, for the purpose of generating electricity unless the fuel burned

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consists of more than fifty percent coal on a total heat input or mass input basis, whichever results in the greater mass feed rate of coal; (5) CCR that is beneficially used; (6) CCR placement at active or abandoned underground or surface coal mines; or (7) municipal solid waste landfills (MSWLF) that receive CCR.

*D. What minimum national criteria are being established for CCR landfills and CCR surface impoundments?*

This final rule establishes minimum national criteria for CCR landfills, CCR surface impoundments, and all lateral expansions of CCR units including location restrictions, liner design criteria, structural integrity requirements, operating criteria, groundwater monitoring and corrective action requirements, closure and post-closure care requirements, and recordkeeping, notification, and internet posting requirements.

*1. Location Restrictions.* To ensure there will be no reasonable probability of adverse effects on health or the environment from the disposal of CCR in CCR landfills, CCR surface impoundments, and all lateral expansions of CCR landfills and CCR surface impoundments (together "CCR units"), this final rule establishes five location restrictions. The location criteria include restrictions relating to placement of CCR above the uppermost aquifer, in wetlands, within fault areas, in seismic impact zones, and in unstable areas. All of these location restrictions require the owner or operator of a CCR unit to demonstrate that they meet the specific criteria. As discussed elsewhere in this preamble, the five location restrictions apply to all new CCR landfills, all new and existing CCR surface impoundments, and all lateral expansions of CCR units; however, existing CCR landfills are only subject to the location restriction for unstable areas. Units that do not meet these restrictions can retrofit or make appropriate engineering demonstrations to meet this criteria. This final rule requires owner or operators of existing CCR units that cannot make the required demonstrations to close, while owners or operators of new CCR units and all lateral expansions who fail to make the required demonstrations are prohibited from placing CCR in the CCR unit.

*2. Liner Design Criteria.* The final rule also establishes liner design criteria to help prevent contaminants in CCR from leaching from the CCR unit and contaminating groundwater. All new CCR landfills, new CCR surface impoundments, and lateral expansions of CCR units must be lined with composite liner, which is a liner system consisting of two components—a geomembrane and a two-foot layer of compacted soil—installed in direct and uniform contact with one another. The final rule allows an owner or operator to construct a new CCR unit with an alternative composite liner, provided the alternative composite liner performs no less effectively than the composite liner. In addition, new landfills are required to operate with a leachate collection and removal system which is designed to remove excess leachate that may accumulate on top of the composite (or alternative composite) liner. Existing CCR landfills are not required to close or retrofit with a composite (or alternative composite) liner and a leachate collection and removal system. These existing CCR units can continue to receive CCR after this rule is in effect; however, the CCR units must meet all applicable groundwater monitoring and corrective action criteria to address any groundwater releases promptly. Existing CCR surface impoundments can also continue to operate as designed. However, if the existing CCR surface impoundment was not constructed with a composite (or alternative composite) liner or with at least two feet of compacted soil with a specified hydraulic conductivity, the rule would require the unit to retrofit or close if the CCR surface impoundment detects concentrations of one or more constituents listed in appendix IV at statistically significant levels above the groundwater protection standard established by the rule.

*3. Structural Integrity Requirements.* To help prevent the damages associated with structural failures of CCR surface impoundments, the final rule establishes structural integrity criteria for new and existing surface impoundments (and all lateral expansions) as part of the design criteria. While the applicability of the structural integrity requirements to individual CCR surface impoundments vary depending on factors such as dike heights and the potential for loss of life, environmental damage and economic loss if there is a dike failure, the final rule establishes requirements for owner or operators to conduct a number of structural integrity-related assessments regularly. These include: (1) Conducting periodic hazard potential classification assessments to assess the potential adverse incremental consequences that would occur if there was a failure of the CCR surface impoundment; (2) conducting periodic structural stability assessments by a qualified professional engineer to document whether the design, construction, operation and maintenance is consistent with recognized and generally accepted good engineering practices; and (3) conducting periodic safety factor assessments to document whether the CCR unit achieves minimum factors of safety for slope stability. If a CCR unit required to conduct a safety factor assessment fails to demonstrate that the unit achieves the specified factors of safety, the owner or operator must close the unit. In addition, certain CCR surface impoundments are required to develop an emergency action plan which defines the events and circumstances involving the CCR unit that represent an emergency and identifies the actions that will be taken in the event of a safety emergency.

*4. Operating Criteria.* The operating criteria include air criteria for all CCR units, run-on and run-off controls for CCR landfills, hydrologic and hydraulic capacity requirements for CCR surface impoundments, and periodic inspection requirements for all CCR units. These criteria address the day-to-day operations of CCR units and are established to prevent health and environmental impacts from CCR units. The air criteria address the pollution caused by windblown dust from CCR units, and require owners and operators to minimize CCR from becoming airborne at the facility. The run-on controls for CCR landfills minimize the amount of surface water entering the unit that will help prevent erosion, surface discharges of CCR in solution or suspension, and will mitigate the generation of landfill leachate, while run-off controls help prevent erosion, protect downstream surface water from releases from the unit, and minimize storm water run-off volume and velocity. CCR surface impoundments are subject to hydrologic and hydraulic capacity requirements to ensure the unit can safely handle flood flows, which will help prevent uncontrolled overtopping of the unit or erosion of the materials used to construct the surface impoundment. The final rule also requires periodic inspections of CCR units to identify any appearance of structural weakness or other conditions that are not consistent with recognized and generally accepted good engineering standards.

*5. Groundwater Monitoring and Corrective Action.* The groundwater monitoring and corrective action criteria require an owner or operator of a CCR unit to install a system of monitoring wells and specify procedures for sampling these wells, in addition to methods for analyzing the groundwater data collected, to detect the presence of

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hazardous constituents (*e.g.*, toxic metals) and other monitoring parameters (*e.g.*, pH, total dissolved solids) released from the units. The final rule establishes a groundwater monitoring program consisting of detection monitoring, assessment monitoring and corrective action. Once a groundwater monitoring system and groundwater monitoring program has been established for a CCR unit, the owner or operator must conduct groundwater monitoring and, if the monitoring demonstrates an exceedance of a groundwater protection standard for any of the identified constituents in CCR, must initiate corrective action.

*6. Closure and Post-Closure Requirements.* The closure and post-closure care criteria require all CCR units to close in accordance with specified standards and to monitor and maintain the units for a period of time after closure, including the groundwater monitoring and corrective action programs. These criteria are essential to ensuring the long-term safety of closed CCR units. Closure of a CCR unit must be completed either by leaving the CCR in place and installing a final cover system or through removal of the CCR and decontamination of the CCR unit. The final rule establishes timeframes to initiate and complete closure activities, and authorize owners or operators to obtain time extensions due to circumstances beyond the facility's control. As discussed elsewhere in this preamble, the rule also establishes alternative closure procedures in situations where an owner or operator is closing a CCR unit, but has no alternative CCR disposal capacity or is permanently closing the coal-fired boiler unit in the foreseeable future. Finally, owners and operators are required to prepare closure and post-closure care plans describing these activities.

*7. Record Keeping, Notification, and Internet Posting Requirements.* The final rule requires owners or operators of CCR units to record certain information in the facility's operating record. In addition, owners and operators are required to provide notification to States and/or appropriate Tribal authorities when the owner or operator places information in the operating record, as well as to maintain a publicly accessible internet site for this information.

*8. Severability.* EPA intends that the provisions of this rule be severable. In the event that any individual provision or part of this rule is invalidated, EPA intends that this would not render the entire rule invalid, and that any individual provisions that can continue to operate will be left in place. The following tables provide a summary of the specific technical requirements applicable to existing and new CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units.

| CCR Landfill Requirements | | | | |
|---|---|---|---|---|
| **Requirement** | **Existing CCR Landfills** | | **New CCR Landfills and Lateral Expansions** | |
| | Required? [1] | Rule Section | Required? [1] | Rule Section |
| Location Restrictions: | √ | §257.64 | √ | §257.60 - §257.64 |
| Placement Above the Uppermost Aquifer | | | √ | §257.60 |
| Wetlands | | | √ | §257.61 |
| Fault Areas | | | √ | §257.62 |
| Seismic Impact Zones | | | √ | §257.63 |
| Unstable Areas | √ | §257.64 | √ | §257.64 |
| Floodplains[2] | √ | §257.3-1 | √ | §257.3-1 |
| Endangered Species[2] | √ | §257.3-2 | √ | §257.3-2 |
| Design Requirements: | | | √ | §257.70 |
| Composite Liner | | | √ | §257.70 (b & c) |
| Leachate Collection and Removal System | | | √ | §257.70 (d) |
| Groundwater Monitoring and Corrective Action | √ | §257.90 - §257.98 | √ | §257.90 - §257.98 |
| Weekly Inspections | √ | §257.84 (a) | √ | §257.84 (a) |
| Annual Inspections | √ | §257.84 (b) | √ | §257.84 (b) |
| Fugitive Dust Controls | √ | §257.80 | √ | §257.80 |
| Run-on, Run-off Controls | √ | §257.81 | √ | §257.81 |
| Surface Water Protection[2] | √ | §257.3-3 | √ | §257.3-3 |
| Closure Requirements | √ | §257.100 - §257.103 | √ | §257.100 - §257.103 |
| Post-Closure Care | √ | §257.104 | √ | §257.104 |
| Recordkeeping Requirements | √ | §257.105 | √ | §257.105 |
| Notification Requirements | √ | §257.106 | √ | §257.106 |
| Publicly Accessible Internet Site Requirements | √ | §257.107 | √ | §257.107 |

[1] √ = required, ▒ = not required.
[2] In existing regulations at 40 CFR part 257, subpart A.

| CCR Surface Impoundment Requirements | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Requirement | Existing Surface Impoundments | | | | New Surface Impoundments and Lateral Expansions | | | |
| | Five feet high AND 20 acre-feet, or 20 feet high | | | | Five feet high AND 20 acre-feet, or 20 feet high | | | |
| | Yes | | No | | Yes | | No | |
| | Required? [1] | Rule Section | Required? [1] | Rule Section | Required? [1] | Rule Section | Required? [1] | Rule Section |
| Location Restrictions: | √ | §257.60 - §257.64 | √ | §257.60 - §257.64 | √ | §257.60 - §257.64 | √ | §257.60 - §257.64 |
| Placement Above the Uppermost Aquifer | √ | §257.60 | √ | §257.60 | √ | §257.60 | √ | §257.60 |
| Wetlands | √ | §257.61 | √ | §257.61 | √ | §257.61 | √ | §257.61 |
| Fault Areas | √ | §257.62 | √ | §257.62 | √ | §257.62 | √ | §257.62 |
| Seismic Impact Zones | √ | §257.63 | √ | §257.63 | √ | §257.63 | √ | §257.63 |
| Unstable Areas | √ | §257.64 | √ | §257.64 | √ | §257.64 | √ | §257.64 |
| Floodplains[4] | √ | §257.3-1 | √ | §257.3-1 | √ | §257.3-1 | √ | §257.3-1 |
| Endangered Species[4] | √ | §257.3-2 | √ | §257.3-2 | √ | §257.3-2 | √ | §257.3-2 |
| Design Requirements: | √ | §257.71 | √ | §257.71 | √ | §257.72 | √ | §257.72 |
| Composite Liner | [2] | §257.71 | [2] | §257.71 | √ | §257.72 | √ | §257.72 |
| Leachate Collection and Removal System | | | | | | | | |
| Groundwater Monitoring and Corrective Action | √ | §257.90 - §257.98 | √ | §257.90 - §257.98 | √ | §257.90 - §257.98 | √ | §257.90 - §257.98 |
| Structural Integrity Criteria: | √ | §257.73 & §257.83 | √ | §257.73 & §257.83 | √ | §257.74 & §257.83 | √ | §257.74 & §257.83 |
| History of Construction | √ | §257.73 (c) | | | | | | |
| Construction Plan | | | | | √ | §257.74 (c) | | |
| Marker [3] | √ | §257.73 (a)(1) | √ | §257.73 (a)(1) | √ | §257.74 (a)(1) | √ | §257.74 (a)(1) |
| Hazard Potential Classification Assessments [3] | √ | §257.73 (a)(2) | √ | §257.73 (a)(2) | √ | §257.74 (a)(2) | √ | §257.74 (a)(2) |
| Structural Stability Assessments | √ | §257.73 (d) | | | √ | §257.74 (d) | | |
| Safety Factor Assessments | √ | §257.73 (e) | | | √ | §257.74 (e) | | |
| Emergency Action Plan [3] | √ | §257.73 (a)(3) | √ | §257.73 (a)(3) | √ | §257.74 (a)(3) | √ | §257.74 (a)(3) |
| Weekly Inspections | √ | §257.83 (a) | √ | §257.83 (a) | √ | §257.83 (a) | √ | §257.83 (a) |
| Annual Inspections | √ | §257.83 (b) | | | √ | §257.83 (b) | | |
| Fugitive Dust Controls | √ | §257.80 | √ | §257.80 | √ | §257.80 | √ | §257.80 |

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| CCR Surface Impoundment Requirements | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Requirement | Existing Surface Impoundments | | | | New Surface Impoundments and Lateral Expansions | | | |
| | Five feet high AND 20 acre-feet, or 20 feet high | | | | Five feet high AND 20 acre-feet, or 20 feet high | | | |
| | Yes | | No | | Yes | | No | |
| | Required? [1] | Rule Section | Required? [1] | Rule Section | Required? [1] | Rule Section | Required? [1] | Rule Section |
| Hydrologic & Hydraulic Capacity Requirements | √ | §257.82 | √ | §257.82 | √ | §257.82 | √ | §257.82 |
| Surface Water Protection[4] | √ | §257.3-3 | √ | §257.3-3 | √ | §257.3-3 | √ | §257.3-3 |
| Closure Requirements | √ | §257.100 - §257.103 | √ | §257.100 - §257.103 | √ | §257.100 - §257.103 | √ | §257.100 - §257.103 |
| Post-Closure Care | √ | §257.104 | √ | §257.104 | √ | §257.104 | √ | §257.104 |
| Recordkeeping Requirements | √ | §257.105 | √ | §257.105 | √ | §257.105 | √ | §257.105 |
| Notification Requirements | √ | §257.106 | √ | §257.106 | √ | §257.106 | √ | §257.106 |
| Publicly Accessible Internet Site Requirements | √ | §257.107 | √ | §257.107 | √ | §257.107 | √ | §257.107 |

[1] √ = required, ▒▒ = not required.
[2] Existing CCR surface impoundments are required to be constructed with two feet of compacted soil with a hydraulic conductivity of no more than $1x10^{-7}$ cm/sec, a composite liner that meets the requirements of §257.70(b), or an alternative liner that meets the requirements of §257.70(c).
[3] This requirement does not apply to an incised CCR surface impoundment.
[4] In existing regulations at 40 CFR part 257, subpart A.

*E. When must owners or operators of CCR landfills and CCR surface impoundments meet the minimum national criteria?*

The rule becomes effective six months after the publication date of this rule. The final rule establishes timeframes for certain technical criteria based on the amount of time determined to be necessary to implement the requirements (*e.g.*, installing the groundwater monitoring wells and establishing the groundwater monitoring program). In establishing these timeframes, EPA accounted for other Agency rulemakings that are anticipated to also affect the owners or operators of CCR units, namely the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (78 FR 34432; proposed rule issued June 7, 2013) and the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (79 FR 34830; proposed rule issued June 18, 2014). Specifically, EPA developed implementation timeframes that would ensure that owner or operators of CCR units would not be required to make decisions about those CCR units without first understanding the implications that such decisions would have for meeting the requirements of all applicable EPA rules.

*F. Deferral of Final Bevill Determination*

This rule defers a final Bevill Regulatory Determination with respect to CCR that is disposed in CCR landfills and CCR surface impoundments until additional information is available on a number of key technical and policy questions. This includes information needed to quantify the risks of CCR disposal, and the potential impacts of recent Agency regulations on the chemical composition of CCR. The Agency also needs further information on adequacy of the state programs.

*G. Beneficial Use*

The final rule retains the Bevill exclusion for CCR that is beneficially used, and provides a definition of beneficial use to distinguish between beneficial use and disposal.

*H. Implementation*

Because the regulations have been promulgated under sections 1008(a), 4004(a), and 4005(a) of RCRA, the rule does not require permits, does not require states to adopt or implement these requirements, and EPA cannot enforce these requirements. Instead, states or citizens can enforce the requirements of this rule under RCRA's citizen suit authority; the states can also continue to enforce any state regulation under their independent state enforcement authority. (For a more detailed discussion of EPA authorities under RCRA and its relationship to this rule, see 75 FR 35128, June 21, 2010). EPA recognizes the significant role states play in implementing these requirements and EPA strongly encourages states to revise their SWMPs to show how these new criteria will be implemented. EPA would then review and approve the revised plan provided it demonstrates that the minimum federal requirements in this final rule will be met. In this way, EPA's approval of a revised plan signals EPA's opinion that the State's SWMP meets the minimum federal criteria. For a more detailed discussion on the role of the states in implementing this rule, please refer to Unit IX of this document.

*I. Characterization of Baseline Affected Entities and CCR Management Practices*

This action will affect CCR generated by coal-fired electric utility plants in the NAICS industry code 221112 (*i.e.*, the "Fossil Fuel Electric Power Generation" industry within the NAICS 22 "Utilities" sector code). Based on 2012 electricity generation data published by the Energy Information Administration (EIA), the Regulatory Impact Analysis (RIA) for this action estimated that a total of 478 operational coal-fired electric utility plants in this NAICS code could be affected by this action. These plants are owned by 242 entities consisting of 166 companies, 17 cooperative organizations, 58 state or local governments, and one federal agency. A sub-total of 81 of the 242 owner entities (*i.e.*, 33 percent may be classified as small businesses, small organizations, or small governments). The 478 coal-fired electric utility plants operate a total of 1,045 CCR management units (735 surface impoundments and 310 landfills). These 478 plants generate 110 million tons of CCR, consisting of 201 plants (42 percent) disposing in on-site landfills, 169 (35 percent) disposing in on-site ponds, and 197 (41 percent) disposing in off-site landfills. Because some plants use more than one CCR management method, these plant counts exceed 478 total plants. In addition, 293 of the 478 plants supply CCR for beneficial uses in at least 14 industries. Nineteen of the 293 plants solely supply CCR for beneficial uses. As of 2012, CCR beneficial uses (*i.e.*, industrial applications) involved about 52 million tons annually.

*J. Summary of Estimated Regulatory Costs and Benefits*

The EPA estimated future regulatory compliance costs and expected future human health and environmental protection benefits can be found in the RIA document which is available from the docket for this action. The estimated costs and benefits for the CCR rule are incremental to the baseline (current) practices by the electric utility industry to manage CCR in accordance with (a) existing state government environmental regulations and (b) utility company CCR management methods.

The RIA estimates the cost of the rule over a 100 year period because of: (1) CCR unit lifespans (40 years to 80 years of age); (2) groundwater migration (estimated time to peak potential exposures of CCR through groundwater migration to drinking water wells is 75 years); and (3) latency periods for onset of illness after exposure to CCR, which can average 20 years.

The table below summarizes the estimated incremental costs and benefits of the rule. The RIA estimates costs to comply with the 12 pollution control requirements associated with the rule, as well as estimated monetized values for 11 expected benefits, and discusses 11 other non-monetized benefits.

EPA Estimated Incremental Costs & Benefits of the CCR Rule

[millions 2013$ over 100-year period of analysis 2015–2114]

| | 3% Discount rate | 7% Discount rate |
|---|---|---|
| A. Annualized Values | | |
| A1. Total Costs | $735 | $509 |
| A2. Total monetized benefits | $294 | $236 |
| A3. Net Benefits (A2–A1) | ($441) | ($441) |
| A4. Benefit to Cost Ratio (A3/A1) | 0.40 | 0.46 |

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EPA ESTIMATED INCREMENTAL COSTS & BENEFITS OF THE CCR RULE—Continued

[millions 2013$ over 100-year period of analysis 2015–2114]

| | 3% Discount rate | 7% Discount rate |
|---|---|---|
| B. Present Value | | |
| B1. Total Costs | $23,200 | $7,260 |
| B2. Total monetized benefits | $8,710 | $3,360 |
| B3. Net Benefits (B2–B1) | ($14,490) | ($3,900) |
| B4. Benefit to Cost Ratio (B2/B1) | 0.38 | 0.46 |

## II. Statutory Authority

These regulations are established under the authority of sections 1006(b), 1008(a), 2002(a), 3001, 4004, and 4005(a) of the Solid Waste Disposal Act of 1970, as amended by the Resource Conservation and Recovery Act of 1976 (RCRA), as amended by the Hazardous and Solid Waste Amendments of 1984 (HSWA), 42 U.S.C. 6906(b), 6907(a), 6912(a), 6944 and 6945(a).

RCRA section 1006(b) directs EPA to integrate the provisions of RCRA for purposes of administration and enforcement and to avoid duplication, to the maximum extent practicable, with the appropriate provisions of other EPA statutes. Section 1006(b) conditions EPA's authority to reduce or eliminate RCRA requirements on the Agency's ability to demonstrate that the integration meets RCRA's protectiveness mandate (42 U.S.C. 6005(b)(1)). *See Chemical Waste Management* v. *EPA*, 976 F.2d 2, 23, 25 (D.C. Cir. 1992).

RCRA section 1008(a) authorizes EPA to publish "suggested guidelines for solid waste management." 42 U.S.C. 6907(a). RCRA defines solid waste management as "the systematic administration of activities which provide for the collection, source separation, storage, transportation, transfer, processing, treatment, and disposal of solid waste." 42 U.S.C. 6903(28).

Pursuant to section 1008(a)(3), the guidelines are to include the minimum criteria to be used by the states to define the solid waste management practices that constitute the open dumping of solid waste or hazardous waste and are prohibited as "open dumping"under section 4005. Only those requirements promulgated under the authority of section 1008(a)(3) are enforceable under section 7002 of RCRA.

RCRA section 4004 generally requires EPA to promulgate regulations containing criteria for determining which facilities shall be classified as sanitary landfills (and therefore not "open dumps"). The statute directs that, "at a minimum, the criteria are to ensure that units are classified as sanitary landfills only if there is no reasonable probability of adverse effects on health or the environment from disposal of solid wastes at such facility." 42 U.S.C. 6944(a).

RCRA section 4005(a), entitled "Closing or upgrading of existing open dumps" generally establishes the key implementation and enforcement provisions applicable to EPA regulations issued under sections 1008(a) and 4004(a). Specifically, this section prohibits any solid waste management practices or disposal of solid waste that does not comply with EPA regulations issued under RCRA section 1008(a) and 4004(a). 42 U.S.C. 6944(a). See also 42 U.S.C. 6903(14) (definition of "open dump"). This prohibition takes effect "upon promulgation" of any rules issued under section 1008(a)(3) and is enforceable through a citizen suit brought pursuant to section 7002. As a general matter, this means that facilities must be in compliance with any EPA rules issued under this section no later than the effective date of such rules, or be subject to a citizen suit for "open dumping" 42 U.S.C. 6945. RCRA section 4005 also directs that open dumps, *i.e.*, facilities out of compliance with EPA's criteria, must be "closed or upgraded."

Section 7004 lays out specific requirements relating to public participation in regulatory actions under RCRA. Subsection (b) provides that "[p]ublic participation in the . . . implementation, and enforcement of any regulation under this chapter shall be provided for, encouraged, and assisted by the Administrator." 42 U.S.C. 6974(b).

### *A. Regulation of Solid Wastes Under RCRA Subtitle D*

Solid wastes that are neither a listed nor characteristic hazardous waste are subject to the requirements of RCRA subtitle D. Subtitle D of RCRA establishes a framework for federal, state, and local government cooperation in controlling the management of non-hazardous solid waste. The federal role is to establish the overall regulatory direction, by providing minimum nationwide standards that will protect human health and the environment, and to provide technical assistance to states for planning and developing their own environmentally sound waste management practices. The actual planning and any direct implementation of solid waste programs under RCRA subtitle D, however, remains a state and local function, and the Act envisions that states will devise programs to deal with state-specific conditions and needs. EPA has no role in the planning and direct implementation of the minimum national criteria or solid waste programs under RCRA subtitle D, and has no authority to enforce the criteria. However, states are not required to adopt solid waste management programs, and thus, Congress developed a statutory structure that creates incentives for states to implement and enforce the federal criteria, but that does not necessarily rely on or require a regulatory entity to oversee or implement them. While Congress developed the statutory structure to create incentives for states to implement and enforce the federal criteria, it does not require them to do so. As a result, subtitle D is also structured to be self-implementing.

RCRA sections 1008(a)(3) and 4004(a) delegate broad authority to EPA to establish regulations governing the management of solid waste. Under section 4004(a) EPA is charged with establishing requirements to ensure that facilities will be classified as sanitary landfills "only if there is no reasonable probability of adverse effects on health or the environment from the disposal of solid waste" at the facility. Or in other words, under section 4004(a) EPA is charged with issuing regulations to address all "reasonable probabilities of adverse effects" (*i.e.*, all reasonably anticipated risks) to health and the environment from the disposal of solid waste. Section 1008(a)(3) expands EPA's authority to address the risks from any of the listed activities. Specifically, EPA is authorized to establish requirements applicable to "storage, transportation, transfer, processing, treatment, and disposal of solid waste." (42 U.S.C. 6907(a), 6903(28)).

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EPA interprets the standard in section 4004(a) to apply equally to criteria issued under sections 1008(a)(3) and 4004(a); namely that the criteria must ensure that a facility is to be classified as a sanitary landfill, and thus allowed to continue to operate, "only if there is no reasonable probability of adverse effects on health or the environment" from either the disposal or other solid waste management practices at the facility. Thus, under the combined authority conferred by sections 1008(a)(3) and 4004(a), a facility is an "open dump" if it engages in any activity involving the management of solid waste that does not meet the standard in section 4004(a); or in other words, any activity involved with the management of solid waste that presents a reasonable probability of causing adverse effects on health or the environment. EPA also interprets these provisions to authorize the establishment of criteria that define the manner in which facilities upgrade or close, consistent with the standard in section 4004(a), to ensure there will be no reasonable probability of adverse effects on health or the environment.

As discussed previously, Congress created a regulatory structure that limited EPA's role to the creation of national criteria that would operate even in the absence of a regulatory entity to oversee or implement the criteria. Under RCRA section 4005(a), upon promulgation of criteria under section 1008(a)(3), any solid waste management practice or disposal of solid waste that constitutes the "open dumping" of solid waste is prohibited. The federal standards apply directly to the facility (are self-implementing) and facilities are directly responsible for ensuring that their operations comply with these requirements. States are not required to incorporate or implement these requirements under any state permitting program or other state law requirement, and EPA is not authorized to impose such requirements, directly or indirectly on the states. States and citizens may enforce this prohibition (and therefore, the federal criteria) using the authority under RCRA section 7002.[1]

The statute also creates incentives to states to implement the criteria. Chief among the incentives is a greater role in implementation and enforcement of the solid waste program, including to a limited extent the ability to give facilities that are operating within their state additional time to come into compliance with newly promulgated EPA criteria. Specifically, if the facility is located in a state with a plan that was approved under section 4003(b), the state may grant the facility an extension of up to five years from the date the final rule was published in the **Federal Register** to come into compliance with EPA regulations, provided: (a) The facility is listed in a state inventory of open dumps; and (b) the facility has demonstrated that it has considered other public or private alternatives for solid waste management to comply with the prohibition on open dumping and is unable to utilize such alternative. For facilities that meet these requirements, the state may establish a "schedule for compliance" which specifies a schedule of remedial measures, including an enforceable sequence of actions or operations, leading to compliance with the requirements "within a reasonable time (not to exceed five years from the date of publication of criteria under section [1008] (a)(3) of this title)." 42 U.S.C. 6945(a).

As a consequence of this statutory structure—the requirement to establish national criteria and the absence of any requirement for direct regulatory oversight—to establish the criteria EPA must demonstrate, through factual evidence available in the rulemaking record, that the final rule will achieve the statutory standard ("no reasonable probability of adverse effects on health or the environment") at all sites subject to the standards based exclusively on the final rule provisions. This means that the standards must account for and be protective of all sites, including those that are highly vulnerable.

## III. Background

### *A. EPA's Proposed Rule*

On June 21, 2010 (75 FR 35128), EPA proposed to regulate CCR under RCRA to address the risks from the disposal of CCR generated from the combustion of coal at electric utilities and independent power producers. As described in the proposal, CCR are residuals generated from the combustion of coal and include fly ash, bottom ash, boiler slag (all composed predominantly of silica and aluminosilicates), and flue gas desulfurization (FGD) materials (predominantly Ca-$SO_X$ compounds) and can be managed in either wet (surface impoundments) or dry (landfills) disposal systems. EPA noted in the proposed rule that the constituents of most environmental concern in CCR are metals, such as antimony, arsenic, barium, beryllium, cadmium, chromium, lead, mercury, nickel, selenium, silver and thallium. EPA also presented data showing numerous instances where these constituents (especially arsenic) have leached at levels of concern from unlined and inadequately clay-lined landfills and surface impoundments.

In the proposal, EPA revisited its August 1993 and May 2000 Bevill Regulatory Determinations regarding CCR generated at electric utilities and independent power producers. The results from this effort led the Agency to consider two primary options for the management of CCR and thus, propose two alternative regulatory strategies. Under the first option, EPA proposed to reverse its August 1993 and May 2000 Bevill Regulatory Determinations (58 FR 42466 and 65 FR 32214 respectively) regarding CCR and to list these residuals as special wastes subject to regulation under subtitle C of RCRA when they are destined for disposal in landfills or surface impoundments. Under this proposed option, CCR would be regulated from the point of generation to the point of final disposition and would generally be subject to the existing subtitle C regulations at 40 CFR parts 260 through 268, as well as the permitting requirements in 40 CFR part 270, and the state authorization process in 40 CFR parts 271–272. Among other things, the regulatory requirements included waste characterization, location restrictions, liner and, if applicable, leachate collection requirements for land disposal units, fugitive dust controls, groundwater monitoring and corrective action requirements, closure and post-closure care requirements, financial assurance, permitting requirements, and recordkeeping and reporting requirements. This option also imposed requirements on generators and transporters of CCR destined for disposal, including manifesting (if the CCR destined for disposal is sent off-site). However, in light of practical difficulties in implementing certain subtitle C regulatory requirements, EPA also proposed to revise selected requirements under the subtitle C option. Consequently, EPA proposed, pursuant to its authority under section 3004(x) of RCRA, modifications to the CCR landfill and surface impoundment liner and leak detection system requirements, the effective dates for the land disposal restrictions, and the surface impoundment retrofit requirements. EPA also proposed to establish new land disposal prohibitions and treatment standards for both wastewater and non-wastewater forms of CCR. In part, the proposed

[1] EPA also may act if the handling, storage, treatment, transportation, or disposal of such wastes may present an imminent and substantial endangerment to health or the environment, pursuant to RCRA section 7003.

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modifications to the treatment standards would result in the closure of existing surface impoundments and the prohibition of all new surface impoundments. (See 75 FR 35128 for a complete discussion of this proposed option).

Under the second option, EPA proposed to retain the August 1993 and May 2000 Bevill Regulatory Determinations and to regulate CCR disposal under subtitle D of RCRA by issuing national minimum criteria to ensure the safe disposal of CCR in surface impoundments and landfills. Under this option, CCR would remain classified as a non-hazardous RCRA solid waste. EPA proposed to establish technical requirements, many of which were nearly identical to the technical standards proposed under the subtitle C option. The technical standards included, among other things, locations standards, liner and leachate collection requirements, groundwater monitoring and corrective action standards for releases from the units, operating criteria, such as fugitive dust control, closure and post-closure care requirements, and recordkeeping and reporting requirements. Under this option, EPA did not propose to establish regulatory requirements that would restrict the generation, transportation, storage, or treatment of CCR prior to disposal, nor did EPA propose to establish financial assurance requirements under RCRA.[2] Also, because of subtitle D's limitations, the proposed rule did not require permits; nor could EPA enforce the national minimum criteria. Rather, states or citizens could enforce the national minimum criteria under RCRA's citizen suit authority, and states could continue to enforce any state regulation that applies to CCR under their independent state enforcement authority.

The subtitle D proposed option was designed to be self-implementing, meaning that the requirements were such that facilities could comply with the regulatory requirements without the need to interact with a regulatory authority. EPA sought to enhance the protectiveness of the proposed option by requiring certified demonstrations by an independent registered professional engineer to provide verification that the regulatory requirements were being adhered to. In addition, the option provided for state and public notification of the certifications, as well as required posting of certain information on a Web site maintained by the facility and in the operating record. (See 75 FR 35128 for a complete discussion of this proposed option).[3]

The Agency also described other alternatives considered. For example, one subtitle D option, called "D-prime" was structured so that all existing CCR surface impoundments could continue to receive CCR after the effective date of the rule for the remainder of the unit's useful life, irrespective of their liner type, provided the other provisions of the subtitle D option were met (*e.g.,* groundwater monitoring). (See 75 FR 35128 for a complete discussion of this and other possible regulatory alternatives on which the Agency solicited comment.)

Under both the subtitle C and subtitle D alternatives, EPA proposed establishing dam safety requirements to address the structural integrity of surface impoundments. EPA also proposed not to change the May 2000 Regulatory Determination for beneficially used CCR, which are currently exempt from the hazardous waste regulations under section 3001(b)(3)(A) of RCRA. EPA also did not propose to address the placement of CCR in mines, or non-minefill uses of CCR at coal mine sites.

In addition to proposing these two regulatory options for the management of CCR, EPA identified many issues on which it solicited comment, information, and data. Certain solicitations were very general, such as comments on alternative options for regulating CCR, while other requests for comment were very specific in nature, for example, whether clay liners designed to meet a specified hydraulic conductivity might perform differently in practices than modeled in the risk assessment. (The Agency requested comment on issues throughout the preamble; however specific issues for which EPA solicited comment can be found at 75 FR 35221–34224.)

### *B. Comments Received on the Proposed Rule*

The Agency received over 450,000 comments on the proposed rule. The majority of the commenters focused on which regulatory path the Agency should pursue for regulating CCR, *i.e.,* RCRA's subtitle C or subtitle D. A number of commenters, however, argued that no additional regulation was necessary and that the states were adequately regulating the management of CCR. Generally, environmental groups and individual citizens favored a subtitle C rule arguing that state programs have failed and damage cases are growing in number. State organizations, individual states, and industry groups (electric utilities, recycling firms, trade associations), largely favored a subtitle D rule with a permitting program.

One area that received extensive comment was the re-evaluation of the eight Bevill study factors.[4] Numerous commenters provided detailed analysis related to the study factors and provided their own interpretations of the data (*e.g.,* state programs and damage cases). Other areas that received significant comment included beneficial use and the risk assessment.

Discussion of the specific comments germane to this rulemaking are provided in the relevant sections of this document.

### *C. Other Actions During Which Comment Was Taken*

#### 1. Public Hearings

EPA conducted eight public hearings during the months of August, September, and October in 2010. There were over 1300 individual speakers at the eight public hearings that commented on the proposed rule. Testimony at the public hearings focused generally on whether EPA

[2] In the proposal, the Agency stated that the RCRA subtitle D alternative did not include proposed financial responsibility requirements and that any such requirements would be proposed separately. The Agency solicited comment on whether financial responsibility requirements under CERCLA section 108(b) should be a key Agency focus under a RCRA subtitle D approach. While the Agency received numerous comments urging the Agency to establish financial responsibility as part of the subtitle D option, the CERCLA 108(b) option did not receive significant support. As discussed in the proposal and reiterated here, EPA will not be requiring financial assurance requirements as part of this rule. The Agency however will continue to investigate the use of other statutory authorities (*e.g.,* CERCLA) to establish financial responsibility requirements for owners or operators of CCR landfills, CCR surface impoundments and any lateral expansion.

[3] While EPA cannot enforce the subtitle D proposed rules, EPA can take action under section 7003 of RCRA to abate conditions that "may present an imminent and substantial endangerment to health or the environment." EPA can also use the imminent and substantial endangerment authorities under the CERCLA, or under other federal authorities to address those circumstances where a unit(s) may pose a threat.

[4] In considering whether to retain or to reverse the August 1993 and May 2000 Regulatory Determinations regarding the Bevill exemption of CCR destined for disposal, the Agency re-examined the RCRA section 8002(n) study factors. These eight study factors are: (1) Source and volumes of CCR generated per year; (2) present disposal and utilization practices (which includes evaluation of existing state regulatory oversight and beneficial use); (3) potential danger, if any, to human health and the environment from the disposal and reuse of CCR; (4) documented cases in which danger to human health or the environment from surface runoff or leachate has been proved; (5) alternatives to current disposal methods; (6) the cost of such alternative disposal methods; (7) the impact of the alternative disposal methods on the use of coal and other natural resources; and (8) the current and potential utilization of CCR (see 75 FR 35128).

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should adopt a subtitle C or subtitle D approach for regulating CCR. Many commenters were also concerned with fugitive dust emissions and the affect these emissions had on their health and overall well-being. Other commenters were concerned that adopting a subtitle C rule for CCR would negatively affect the beneficial use of the material. In addition to their testimonies that were entered into the rulemaking record, over 1200 additional documents were submitted in hard copy and entered into the docket (see EPA–HQ–RCRA–2009–0640).

2. Notices of Data Availability

Subsequent to the proposed rule, the Agency published several Notices of Data Availability (NODAs), the first on October 21, 2010, (75 FR 64974); the second on October 12, 2011 (76 FR 63252) and the third on August 2, 2013 (78 FR 46940). Specifically:

- The first NODA invited comment on the responses EPA received on Information Collection Requests that were sent to electric utilities on their CCR surface impoundments, as well as reports and materials related to the site assessments EPA had conducted on a subset of these impoundments.
- The second NODA invited comment on a number of topics, including (1) chemical constituent data from coal combustion residuals; (2) facility and waste management unit data; (3) information on additional alleged damage cases; (4) the adequacy of state programs; and (5) beneficial use.
- The third NODA invited comment on (1) supplemental data for the risk assessment; (2) supplemental data for the RIA; (3) information regarding large-scale fill; and (4) data on the CCR Assessment Program. EPA also sought comment on two technical issues associated with the requirements for CCR management units: closure requirements and regulation of overfills (*i.e.,* CCR management units built directly over pre-existing CCR landfills or CCR surface impoundments).

Specific comments received on each of the three NODAs are discussed in the relevant sections of this rule.

3. Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category Proposed Rule

On June 7, 2013 (78 FR 34432), EPA proposed a regulation that would strengthen the controls on discharges from certain steam electric power plants by revising the technology-based effluent limitation guidelines (ELG) and standards for the steam electric power generating point source category. As part of this proposal, EPA discussed its current thinking on how a final RCRA CCR rule might be aligned and structured to account for any final requirements adopted under the ELG for the Steam Electric Power Generating point source category. Two primary means of integrating the two rules were discussed: (1) Coordinating the design of any final substantive CCR regulatory requirements and (2) coordinating the timing and implementation of the rules to allow facilities to coordinate their compliance planning and implementation and to protect electricity reliability for consumers. EPA stated that consistent with RCRA section 1006(b), effective coordination of any final RCRA requirements with the ELG requirements would be sought in order to minimize the overall complexity of the two regulatory structures, and facilitate implementation of engineering, financial, and permitting activities. EPA solicited comments on how any final CCR final rule might be aligned and structured to account for any final requirements adopted under the ELG for the Steam Electric Power Generation point source category.

*D. EPA's CCR Assessment Program*

In March 2009, the Agency's CCR Assessment Program (herein referred to as the Assessment Program) was initiated. This effort was in response to the December 22, 2008 dike failure of a coal ash impoundment at the Tennessee Valley Authority (TVA) Kingston Fossil Plant in Harriman, Tennessee where over one billion gallons of coal ash slurry were released, affecting more than 300 acres, including residences and infrastructure. The TVA Kingston impoundment failure ignited a nation-wide concern over the safety of coal ash impoundments; and EPA was tasked with determining whether the potential existed for similar impoundment failures at other coal-fired power plants. In response, EPA developed the Assessment Program to evaluate the structural stability and safety of all coal ash impoundments throughout the country.[5] As of September 2014, 559 impoundments had been assessed at over 230 coal-fired power plants.

The Assessment Program began as a separate effort from the development of this final rule.[6] However, the information and experience developed in carrying out the site assessments during the Assessment Program is directly relevant to many of the issues addressed in this rulemaking, and provide further technical support for many of the technical criteria. Consequently, many of the final technical criteria were developed in direct response to findings from the site assessments. For example, several of the technical criteria contained in the proposed rule were modified to account for the widely accepted engineering methodologies and practices used in conducting the site assessments, as well as current facility practices documented during the assessments. In a few instances, the criteria were supplemented to better align the technical requirements with the Assessment Program. Included among the final criteria that directly rely on the Assessment Program are the provisions relating to structural integrity assessments to address factors of safety, periodic reassessments, hazard potential classifications, and the hydrologic and hydraulic capacity of CCR surface impoundments. These requirements are further discussed in Unit VI of this preamble.

The Assessment Program focused on impoundments meeting four general criteria that were designed to identify the units most likely to present the same risks as the collapsed TVA impoundment: (1) Above ground or diked; (2) of sufficient height to be susceptible to structural failure (*i.e.,* six feet); (3) receiving CCR; and (4) located at operating coal-fired power plants selling power to the electric grid. Also included in the assessments were a number of inactive impoundments, *i.e.,* impoundments not receiving CCR but still containing CCR and/or liquid. The Agency included these inactive units in the assessment reasoning that these units would be as susceptible to structural failure as units currently receiving CCR, given that they still contained CCR and maintained an ability to impound liquid (*i.e.,* the unit had not been breached). The Assessment Program did not evaluate, however, incised (not having above ground berms or dikes) impoundments or landfills (not containing liquid slurried CCR wastes). EPA chose not to assess these units because they did not share the characteristics of

[5] The focus of the Assessment Program was to assess the structural integrity of CCR impoundments meeting specified criteria. The Agency did not include, as part of its evaluation, the assessment of other conditions/characteristics of the impoundment that may present potential risks to human health or the environment, *i.e.,* groundwater contamination due to an insufficient liner design.

[6] EPA issued two Notices of Data Availability (75 FR 35128 (October 21, 2010) and 78 FR 46940 (August 2, 2013)) specifically soliciting comment on the information generated by the Assessment Program and the materials posted on our Web site.

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impoundments likely to raise concern for catastrophic releases, and because no known catastrophic structural failures were associated with these types of units.

Prior to initiating the assessments, EPA consulted with two key dam safety organizations, the Association of State Dam Safety Officials (ASDSO) and the Mine Safety and Health Administration (MSHA) to better understand how these federal and state dam inspection programs operated, including how earthen dams and impoundments were assessed.[7] These groups provided the Agency with critical insight and information for inspecting and evaluating CCR impoundments. The Agency also reviewed various technical documents relating to dam safety and conducting impoundment inspections, many of which were recommended by these organizations. They were: (1) U.S. Army Corp of Engineers (USACE) 2008 National Inventory of Dams (NIDS); (2) Federal Emergency Management Agency's (FEMA) Federal Guidelines for Dam Safety—Hazard Potential Classification System for Dams (April 2004); (3) FEMA's Risk Prioritization Tool for Dams User Manual (March 2008); (4) MSHA's Handbook (PH07–01); (5) MSHA's Coal Mine Impoundment Inspection and Plan Review Handbook (October 2007); and (6) MSHA's Engineering and Design Manual: Coal Refuse Disposal Facility (May 2009); (7) ASDSO's "Summary of State Dam Safety Laws and Regulations," (2000); (8) ASDSO's "Owner Responsible Periodic Inspection Guidance," (2005); (9) "Guidelines for Inspections of Existing Dams." New Jersey Department of Environmental Protection—Dam Safety (January 2008).

In developing the criteria that were used to conduct the assessments, a standard rating system was developed to classify the units' suitability for continued safe and reliable operation. EPA modeled its impoundment condition rating criteria on those developed by the State of New Jersey (see reference above).

1. Conducting the Site Assessments

In order to prioritize the assessments, a preliminary hazard potential classification ranking was identified for each impoundment, based on criteria developed by the FEMA and found generally in USACE's NID. EPA elected to evaluate first those impoundments with a high hazard potential classification, which signifies that a failure or mis-operation of the unit would probably result in the loss of human life.

Upon initiation of the Assessment Program, every owner or operator of a CCR impoundment was contacted by the Agency and supplied with information on the objectives of the assessment and how the assessments were to be conducted. Assessments were conducted in rounds, consisting of groups of 12–26 facilities per round.[8] Prior to each site assessment, to ensure uniformity throughout the study, a statement of work and an impoundment field checklist was developed and adhered to during the assessment.

To ensure objectivity, EPA contracted with professional engineers (PEs) in the state where the impoundment was located who were experts in the area of dam safety to perform the site assessments. Each individual assessment was performed by PEs qualified in the areas of geotechnical engineering, hydrology and hydraulics, and overall dam safety. Upon evaluation of a robust set of technical documents addressing dam safety and inspections as well as comprehensive discussions with key dam safety organizations, the Assessment Program developed a comprehensive set of factors that were to be used to evaluate the overall safety of CCR surface impoundments, which concluded that, among other important factors, the static and seismic factors of safety, hydrologic and hydraulic capacity, liquefaction potential analysis and a post-liquefaction stability analysis if the soils of the embankment were identified to be susceptible to liquefaction, and operation and maintenance protocols, *e.g.* instrumentation monitoring, inspection program, emergency response protocols were critical parameters for assessing the overall safety of CCR surface impoundments.

The individual evaluations or assessments were conducted at each impoundment at each facility using standard, accepted engineering practices, including a visual assessment of the CCR surface impoundment, interviews with site personnel, a review of the history of the CCR surface impoundment, and a review of engineering documentation related to the design, construction, operation, and maintenance of the impoundments, including available technical analyses. At each site visit, additional documentation was collected and reviewed as available, including descriptions, along with supporting information, of: (1) The impoundment, including location, size, age, design and/or alterations to the design, and the amount of residuals currently in the unit; (2) known, measured settlement of the impoundment embankment; (3) known, measured movement of the impoundment embankment; (4) observed erosion of the impoundment embankment; (5) seepage; (6) leakage; (7); observed cracking of the impoundment embankment; (8) deterioration, such as scarps, boils, or sloughs, of the — embankment; (9); seismicity; (10) internal stresses; (11) functioning of foundation drains and relief wells; (12) stability of critical slopes adjacent to the units; and (13) regional and site geological conditions. If available, state and federal inspections reports were also reviewed.[9]

In addition, for each assessment, the following factors were identified, to the extent feasible, for evaluation: (1) The presence and adequacy of spillways; (2) hydrologic and hydraulic capacity of the unit; (3) overall structural adequacy and stability of structures under all credible loading conditions through a review of static, seismic, and liquefaction analyses with determined factors of safety; (4) soil, groundwater, surface water, geology, and geohydrology characteristics associated with the unit, including hydrological data accumulated since the impoundment was constructed or last inspected; (5) a history of the performance of the management unit through analysis of data from monitoring instruments, interviews with facility personnel, and review of available operating records; (6) quality and adequacy of maintenance, surveillance, and methods of unit operations for the protection of public safety; (7) location of schools, hospitals, or other critical infrastructures within five miles down gradient of the impoundment; and (8) whether the impoundment is located within federally designated flood plains. Finally, each impoundment and any associated spillways were evaluated to determine whether the impoundment and the spillways could withstand the loading or overtopping from appropriate inflow design flood events.

Each CCR surface impoundment was classified with a hazard potential classification following the New Jersey Department of Environmental Protection

[7] ASDSO identified for EPA key documents to review including Federal Energy Regulatory Commission (FERC) and MSHA guidance.

[8] The results of this effort are either presented on a facility by facility basis or are summarized by round. All of these data have been posted on the Agency Web site.

[9] It is important to note that during the assessment, no physical drilling, coring or sampling was conducted, while on site; however, studies were reviewed that often included such information.

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Bureau of Dam Safety and Flood Control's hazard potential ranking. Each impoundment was classified with a hazard potential classification of either; "high," "significant," "low," or "less-than-low." The hazard potential classification was a qualitative assessment of the potential adverse incremental consequences of a dam failure.

At the conclusion of each assessment, a report was generated and the impoundment was given a condition rating of either; satisfactory, fair, poor, or unsatisfactory. The condition ratings were based on the availability of information on the unit and evaluation of the previously mentioned factors, including the static, seismic, and liquefaction factors of safety. No impoundments received an "unsatisfactory" rating. Numerous impoundments were, however, rated as "poor," often for lack of appropriate technical documentation in the aforementioned areas. "Poor" or "fair" ratings were also an indication that additional measures were needed to improve the stability of the unit. Of 559 impoundments assessed, 241 received a condition rating of "satisfactory," 166 received a condition rating of "fair," and 152 received a "poor" condition rating.

It is important to note that the condition rating did not necessarily imply that the unit had inadequate structural integrity. On the contrary, in many instances a structurally sound impoundment may have been given a condition rating or "fair" or "poor" based on other factors such as a lack of documented information on the unit or insufficient operations and maintenance protocols. For example, an impoundment could be rated as "poor" if it lacked the appropriate technical documentation and analyses regarding structural or hydrologic and hydraulic analyses. EPA rated numerous units as "poor" based primarily on unavailable technical analyses.

Once the assessment was performed, a draft report was prepared. Draft reports were reviewed by the appropriate state agency, the utility, and by EPA.[10] Once comments were received and incorporated, a final report was issued along with recommendations for additional actions to be taken by the facility (if needed). Facilities then developed action plans and schedules to implement the recommendations. EPA also informed facility owners and operators that in addition to implementing their action plans, they need to adopt an ongoing, routine program to assess each surface impoundment and to take necessary corrective measures to ensure the units' continued structural integrity.

2. Assessment Program Findings

Upon completion of the Assessment Program, a review was undertaken to ascertain the key findings or lessons learned from the effort. These key findings included: (1) The majority of CCR surface impoundments are currently inspected on a periodic basis; (2) most utilities were readily able to supplement outdated or missing information with new or updated evaluations of their impoundments after the on-site portion of EPA's assessment was conducted; (3) in response to the assessment report recommendations, facilities typically willingly conducted remedial actions; (4) interaction with the states and the utilities assured accuracy in the final assessment reports; (5) placing site assessment materials on an internet site assured that the public, states, and utilities had full access to information about the design and operation of CCR impoundments and did not present either homeland security or other confidentiality concerns; (6) static, seismic, and liquefaction analyses did not pose a significant technical or cost burden on facilities since many already routinely conducted these types of evaluations; (7) state regulatory bodies viewed the assessments as a means to further support existing assessment programs; and (8) the use of PEs to certify all final reports ensured that the assessments reflected the PE's best judgments.

3. Assessment Program's Support for the Structural Integrity Requirements of the Rule

As noted, the findings from EPA's Assessment Program provide technical and factual support for many of the final requirements for structural stability in this rule. A more detailed discussion of several of the most significant of these is presented below. Additional discussion of the relevance of these findings is included throughout Unit VI of this document.

*a. Periodic Inspections/Assessments*

Consistent with the findings from the assessments and with EPA's recommendations to facilities as part of the Assessment Program, this rule requires that all CCR surface impoundments be inspected at intervals not exceeding seven days for any appearances of actual or potential structural weakness and other conditions that are disrupting or have the potential to disrupt the operation or safety of the CCR surface impoundment. Monitoring of instrumentation is also required to be conducted at intervals not exceeding 30 days. The Assessment Program found that virtually all utility companies conduct some sort of periodic inspection or monitoring at CCR surface impoundments, although practices varied among facilities and between states. The Assessment Program also found that while many facilities were conducting regularly scheduled inspections, some did not adequately document the results of these inspections.

In the final rule, CCR surface impoundments exceeding a specified size threshold, *i.e.,* height of five feet or more and capacity of 20 acre-feet or more or a height of 20 feet or more, are required to perform annual inspections as well as two assessments of structural stability quinquennially, (*i.e.,* every five years) that include a structural stability assessment of specified parameters and a factor of safety assessment. Annual inspections are broader in scope than weekly inspections and are conducted to ensure that the design, construction, operation and maintenance of the CCR unit is consistent with recognized and generally accepted good engineering standards. Annual inspections must include a review of available information regarding the status and condition of the unit and a visual inspection to identify signs of distress or malfunction of the unit and appurtenant structures. The annual inspections must be conducted by a qualified professional engineer.

The Assessment Program also reviewed how detailed structural stability reviews and inspections were recommended to be conducted by FEMA, MSHA, and the USACE guidelines and found that such inspections were recommended to take place every three to five years. Review of state dam safety programs demonstrated that similar detailed inspections were also conducted on a three-to-five year cycle. Therefore, in the final rule, EPA is requiring that structural integrity assessments, including the calculation of factors of safety under various loading conditions, be conducted within 18 months of publication of the rule, and be repeated every five years. The five year review timeframe is based on documentation showing that the factual bases for such reviews are only sound for that time

[10] As noted many times in this document, states play a critical role in implementing and overseeing these units. To assist states in this effort, EPA has, in the majority of cases directly provided the states with all of the information from our assessments. The Assessment Program reports may be accessed at: *http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/surveys2/index.htm.*

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period, and is consistent with federal dam safety guidance, specifically FEMA. FEMA recommends in *Federal Guidelines for Dam Safety* that dams be formally assessed at a frequency not to exceed five years by a qualified professional engineer. EPA has adopted this timeframe to maintain consistency with FEMA guidance. The inspection and assessment requirements in this rule will ensure that there are consistent and uniform inspection and assessment practices across states and facilities and will ensure that problems related to their stability will be promptly identified and remediated as necessary.

*b. Static, Seismic, and Liquefaction Factors of Safety*

*(1)* Static Factors of Safety.

Factor of safety (FOS) means the ratio of the forces tending to resist the failure of a structure, as compared to the forces tending to cause such failure as determined by accepted engineering practice. This analysis is used to determine whether a CCR surface impoundment's dikes are engineered to withstand the specific loading conditions that can be reasonably anticipated to occur during the lifetime of the unit without failure of the dike, if accepted good engineering practices are employed. Static factors of safety refer to the factors of safety (FOS) under static loading conditions that can reasonably be anticipated to occur during the lifetime of the unit. Static loading conditions are unique from other loading conditions (*e.g.,* seismic, liquefaction) in that static loading conditions are those which are in equilibrium, meaning the load is at rest or is applied with constant velocity.

EPA reviewed a series of USACE guidance documents addressing how to determine static FOS. These documents included, but were not limited to, Engineer Manual EM 1110–2–1902 "Slope Stability" (October 2003), and EM 1110–2–1902 "Stability of Earth and Rock-Fill Dams." The Agency also assessed the recommendations on how to conduct static analysis contained in the Engineering and Design Manual for Coal Refuse Disposal Facilities, originally published by the Mining Enforcement and Safety Administration (MESA) in 1975 and updated for MSHA in May 2009, and in particular Chapter 6, "Geotechnical Exploration, Material Testing, Engineering Analysis and Design." Based on recommendations from ASDSO, among others, the Agency adopted the USACE guidance to determine static FOS, both in the Assessment Program and in this rulemaking, as these manuals are recognized throughout industry as the standard routinely used in field assessment of structural integrity.

In EPA's Assessment Program all CCR units were assessed to determine their static FOS. Each assessment classified a CCR unit as having sufficient structural stability under static loading conditions if analysis of critical sections of embankments demonstrated FOS that met or exceeded the values defined by USACE for static specific loading conditions. EPA found that most CCR surface impoundments exhibited sufficient calculated factors of safety under static loading conditions. EPA also found that in those CCR units which insufficient factors of safety against failure due to static loading were calculated, the owner or operator was able to implement actions which increased the factors of safety under static loading conditions to acceptable levels. Oftentimes, these implemented actions were of a simple nature, such as installing riprap (rock armoring the slopes) or buttressing the slopes.

Similarly, this rule adopts the static FOS from USACE Engineer Manual EM 1110–2–1902 "Slope Stability," with the exception of the rapid drawdown loading condition,[11] which was determined not to be relevant to CCR surface impoundments. EPA found the factors of safety identified by EM 1110–2–1902, specifically the Maximum Storage pool, Maximum Surcharge pool, and End-Of-Construction loading conditions, provided consistent, achievable levels of safety in CCR surface impoundment dikes, comprehensively assessed static stability, and provided sufficient consideration of compounding stresses on dikes (*e.g.,* factors of safety values greater than 1.00 to account for unanticipated loadings acting in conjunction or misidentified strength of materials).

*(2)* Seismic Factor of Safety.

Seismic FOS means the FOS determined using analysis under earthquake conditions for a seismic loading event, based on the U.S. Geological Survey (USGS) seismic hazard maps for seismic events with a specified return period for the location where the CCR surface impoundment is located. The seismic FOS analysis is used to determine whether a dam would remain stable during an earthquake or other seismic event. The Agency relied on guidance from USACE and MSHA to evaluate the appropriate methods to determine if a dam would remain stable during a seismic event. This includes the USACE guidance Engineer Circular 1110–2–6061: Safety of Dams—Policy and Procedures 2204, Engineer Circular 1110–2–6000: Selection of Design Earthquakes and Associated Ground Motions 2008, and Engineer Circular 1110–2–6001: Dynamic Stability of Embankment Dams 2004). EPA also reviewed MSHA's 2009 Engineering and Design Manual for Coal Refuse Disposal Facilities, in particular Chapter 7, "Seismic Design: Stability and Deformation Analyses." These documents are viewed by ASDSO, FEMA and MSHA as generally accepted guidance on how to conduct seismic stability analyses.

As noted earlier, in performing the assessments, EPA directed its engineering contractors to assess seismic stability of CCR impoundments during and following a seismic event with a 2% probability of exceedance in 50 years (*i.e.* probable earthquake within approximately 2,500 years) and a horizontal spectral response acceleration for 1.0-second period (5% of Critical Damping). EPA selected this return period for determining the maximum design earthquake (MDE) by first considering the operating life anticipated for CCR surface impoundments. EPA has identified the operating life of CCR surface impoundments to range between 40–80 years. EPA then consulted the United States Geological Survey (USGS) and ASDSO to determine a conservative probability that should be used in the assessments.[12] To reduce the likelihood of a CCR unit failing during a seismic

[11] Rapid (or sudden) drawdown is a condition in earthen dikes that may develop when the embankment becomes saturated through seepage during a high pool elevation in the reservoir. Rapid drawdown becomes a threat to the dike when the reservoir pool is drawn down or lowered at a rate significantly higher than the excess poor water pressure within the dike can dissipate. Typically, rapid drawdown scenarios are considered for dikes with reservoirs used for water supply and management or agricultural supply. In these scenarios, a high pool elevation is maintained in the reservoir in storage months. Subsequently, the water supply is drawn on in months where there is a demand for the reservoirs contents. This drawing down of the pool can present issues for the structural integrity of the unit. However, the management of CCR surface impoundments differs from that of conventional water supply reservoirs. CCR surface impoundments are never used for water supply, and the only instance in which EPA determined through its Assessment Program that rapid drawdown loading conditions would be relevant to CCR surface impoundments was in the event that the CCR surface impoundment had already released the contents of the impoundment through a breach of the dike or emergency discharge. Since the threat of release of CCR and the reservoir has already been realized, any failure due to rapid drawdown of the embankment is no longer critical to the overall containment of the now-released contents of the CCR unit.

[12] Wieland, M., "Seismic Design and Performance Criteria for Large Storage Dams", Proc. 15th World Conf. on Earthquake Engineering, Lisbon, Portugal, Sep. 24–28, 2012.

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event, the Agency assessed various return periods and chose a conservative 2500 year return period. The use of this "return" period was chosen because it is conservative, reflects the fact that many CCR impoundments are located in active seismic zones, and the use of a conservative "return" period ensures that if a unit meets the seismic FOS it is unlikely to fail under most seismic events. By evaluating seismic stability under a conservative return period and requiring the unit to maintain structural stability under that design seismic event, the likelihood of a seismic event occurring at the location of the CCR surface impoundment in which the strength of the unit is exceeded and the unit fails is considerably reduced. Additionally, the unit can reasonably be anticipated to withstand seismic events of a more frequent return period (*i.e.,* smaller magnitude).

The Agency assessed CCR impoundments and classified them as having seismic stability if modeling results of critical failure surfaces were calculated to have a FOS greater than 1.0 under the specified seismic loading condition. The Assessment Program found that most CCR impoundments did meet the required seismic FOS. This rule also adopts this seismic stability FOS under the 2% probability of exceedance in 50 years event.

The Assessment Program found that many CCR impoundments had not undergone static or seismic analyses in sufficient detail that an independent professional engineer could assert that they were stable. The assessments gave impoundments a condition rating of "poor" if the utility was unable to provide static and seismic studies of their units conducted in a fashion which represented acceptable professional engineering practice. As the Assessment Program advanced, many utilities independently conducted new or updated static and seismic analyses of CCR surface impoundments in anticipation of their facilities being assessed. By the end of the program, virtually all facilities had conducted or were in the process of conducting static and seismic analyses. While some utilities noted concern over the costs of conducting additional static or seismic stability studies, none found that completing these studies presented any significant engineering challenges.

(3) Liquefaction Factors of Safety

Liquefaction FOS means the factor of safety determined using analysis under liquefaction conditions. Liquefaction is a phenomenon which typically occurs in loose, saturated or partially-saturated soils in which the effective stress of the soils reduces to zero, corresponding to a total loss of shear strength of the soil. The most common occurrence of liquefaction is in loose soils, typically sands. The liquefaction FOS determination in the final rule is used to determine if a CCR unit would remain stable if the soils of the embankment of the CCR unit were to experience liquefaction. EPA relied primarily on one source to evaluate the appropriate methods to determine if a dam would remain stable under liquefaction conditions. This source was "Soil Liquefaction during Earthquakes," Idriss and Boulanger, Earthquake Engineering Research Institute, 2008.[13] EPA also reviewed several technical resources regarding soil liquefaction, including "Ground Motions and Soil Liquefaction During Earthquakes," Seed and Idriss, 1982,[14] "Liquefaction Resistance of Soils: Summary report from the 1996 and 1998 NCEER/NSF Workshops on Evaluation of Liquefaction Resistance of Soils," Youd and Idriss, 2001,[15] and *Seismic Design Guidance for Municipal Solid Waste Landfill Facilities,* US EPA, Office of Research and Development, 1995.[16] These documents are viewed as generally accepted guidance on how to conduct liquefaction potential analyses and residual strength analyses under post-liquefaction conditions.

As noted earlier, in performing the assessments, EPA assessed the liquefaction potential of soils that compose the embankments of the CCR unit to determine if the soils present in the embankment were of the soil classification and configuration that was susceptible to liquefaction. This determination was based on evidence available through interviews with facility personnel, construction documentation, or representative soil sampling, such as information provided by corings and borings. Identical to the requirements for seismic factor of safety calculation, EPA selected a return period for a seismic event for analysis of liquefaction potential, under a seismic loading which may induce liquefaction in embankments, of a 2% probability of exceedance in 50 years. The discussion of the selection of this return period can be found in the "Seismic Factor of Safety" section above.

The Agency assessed CCR impoundments and classified them as having stability under liquefaction conditions if representative soil sampling, anecdotal evidence from interviews with facility personnel, or construction documentation indicated that there was no susceptibility to liquefaction of the embankment soils or if modeling or analysis in critical failure planes in the embankment expected to be susceptible to liquefaction were calculated to have a FOS greater than 1.00 under post-liquefaction conditions. The Assessment Program found that most CCR surface impoundments did not contain soils in detrimental volumes or configurations in the embankment that would indicate susceptibility to liquefaction. However, the assessment effort found that in embankments with a presence of soils susceptible to liquefaction, most CCR surface impoundments did not meet the required liquefaction FOS.

The Assessment Program found that many CCR surface impoundments had not undergone liquefaction potential analyses or post-liquefaction residual strength analyses in those instances in which liquefaction potential was identified (*i.e.,* soils subject to liquefaction were present). The assessments gave impoundments a condition rating of "poor" if there was no information available to characterize the soils of the embankment, and a condition rating of "poor" or "fair" if post-liquefaction residual strength analysis of soils previously identified as being susceptible to liquefaction had not been available, with the rating dependent on the determined severity of the liquefaction potential in the embankment. Impoundments with calculated liquefaction factors of safety which did not meet or exceed 1.00 were given a condition rating of "poor."

As the Assessment Program advanced, many utilities independently conducted new or updated liquefaction potential analyses or residual strength analyses of CCR surface impoundments in anticipation of their facilities being assessed. By the end of the program, virtually all facilities had conducted or were in the process of conducting liquefaction potential analyses or residual strength analyses. While some utilities noted concern over the costs of

[13] *https://www.eeri.org/products-page/monographs/soil-liquefaction-during-earthquakes-3/.*

[14] Seed, H. B., and Idriss, I. M., 1982, "Ground Motions and Soil Liquefaction During Earthquakes," Monograph No. 5, Earthquake Engineering Research Institute, Berkeley, California, pp. 134.

[15] Youd, T. L., Idriss, I. M., 2001, "Liquefaction Resistance of Soils: Summary report from the 1996 and 1998 NCEER/NSF Workshops on Evaluation of Liquefaction Resistance of Soils." Journal of Geotechnical and Geoenvironmental Engineering, ASCE.

[16] United States EPA, Office of Research and Development, 1995, EPA/600/R–95/051, RCRA Subtitle D (258) Seismic Design Guidance for Municipal Solid Waste Landfill Facilities. Available as of the Writing of this policy at *www.epa.gov/clhtml/pubtitle.html* on the U.S. EPA Web site.

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conducting additional liquefaction potential or residual strength studies, none found that completing these studies presented any significant engineering challenges.

Based on its experience in the Assessment Program and subsequent review of numerous technical resources, EPA determined that a post-liquefaction residual strength factor of safety in the embankment of 1.00 is not sufficient. Liquefaction potential analysis and post-liquefaction residual strength analysis involves a larger degree of uncertainties, *e.g.,* liquefiable stratum configuration, in assumptions and analysis which must be accounted for with a factor of safety above 1.00. The final rule therefore requires CCR surface impoundments which are constructed of soils determined to be susceptible to liquefaction to meet or exceed a liquefaction factor of safety of 1.20. EPA has determined that 1.20 is an appropriate liquefaction factor of safety based on several technical guidances and memos, including *Federal Guidelines for Dam Safety: Earthquake Analyses and Design of Dams,* Document 65, FEMA May 2005, which states that "post-liquefaction factors of safety are generally required to be a minimum of 1.2 to 1.3." [17] [18] [19] [20] [21]

*c. Impoundment Height and Relationship to Regulatory Requirements*

During the Assessment Program, the Agency reviewed the stability issues related to various heights of impoundments. The Assessment Program concluded that impoundments with heights less than five feet or those retaining less than 20 acre feet were unlikely to cause significant environmental or economic loss should they undergo a catastrophic failure. The Agency's review of MSHA and FEMA guidance also noted that "small" units were unlikely to cause significant losses should they fail. Based on the Agency's experience and FEMA and MSHA's guidance, the Agency has concluded that there is a substantial benefit in having impoundments which exceed a specified size threshold, *i.e.,* height of five feet or more and capacity of 20 acre-feet or more or a height of 20 feet or more determine their static, seismic, and liquefaction FOS on a regular basis. The analyses and experience gained in conducting the Assessment Program indicates that a catastrophic failure of a CCR surface impoundment is unlikely to occur so long as the factors of safety are maintained or exceeded throughout the unit's operating life. This conclusion is also consistent with relevant guidance and regulations which do not require such evaluations for units below a certain size threshold.

*d. Hazard Potential Ratings*

Each impoundment assessed in the Assessment Program was given a Hazard Potential Classification rating of either *Less-than-Low, Low, Significant, and High.* Previous classifications were reviewed and amended as necessary to reflect guidance developed for the Assessment Program. The hazard potential ratings refer to the potential for loss of life or damage if there is a dam failure. The ratings do not refer to the condition or structural stability of the dam. Four hazard potential classifications were used in assessing the impoundments in the Assessment Program:

High Hazard Potential—Dams assigned the high hazard potential classification are those where failure or mis-operation will probably cause loss of human life.

Significant Hazard Potential—Dams assigned the significant hazard potential classification are those dams where failure or mis-operation results in no probable loss of human life, but can cause economic loss, environment damage, disruption of lifeline facilities, or impact other concerns. Significant hazard potential classification dams are often located in predominantly rural or agricultural areas, but could be located in areas with population and significant infrastructure.

Low Hazard Potential—Dams assigned the low hazard potential classification are those where failure or mis-operation results in no probable loss of human life and low economic and/or environmental losses. Losses are principally limited to the owner's property.

Less Than Low Hazard Potential—Dams which do not pose high, significant, or low hazard potential.

There is a substantial benefit in having owners or operators of all CCR impoundments determine the hazard potential classification of their units. The Assessment Program found that many CCR surface impoundments had not been given a hazard potential classification and consequently, their potential threat to human health and the environment if a failure were to occur was not clearly identified, nor had response plans been developed to respond to any catastrophic failure. Moreover, these classifications should be updated over time, particularly to account for changes such as population growth, construction of key infrastructure, or changes to the impoundment's size or operation. The Assessment Program also found that some states do not classify CCR impoundments as "dams" and therefore those units may not be required to determine their hazard potential classification or otherwise evaluate the potential effects of a catastrophic failure. Consistent with the guidance from ASDSO, FEMA, and the state of New Jersey, this rule requires that all diked CCR impoundments determine their hazard potential classification according to the definitions set out in this regulation. For those units with a hazard potential classification of significant or high, the owner or operator of such impoundments is also required to develop an Emergency Action Plan to address the higher potential impacts of a potential failure.

*e. Condition Ratings*

While the rule does require facilities to evaluate the same engineering factors that went into developing these ratings, the rule does not require that each impoundment be given a condition rating. After evaluation of the use of these ratings, the Agency determined that the rating may have relied too heavily on subjective factors. For that reason, this rule requires that the qualified professional engineer certify, based on quantitative determinations, that an impoundment meets the requirements for FOS and hydraulic and hydrologic capacity. This approach is less subjective and allows the professional engineer to make quantifiable certifications.

## IV. Bevill Regulatory Determination Relating to CCR From Electric Utilities and Independent Power Producers

As discussed in the preceding sections, in the proposed rule EPA reopened its August 1993 and May 2000 Regulatory Determinations regarding CCR generated at electric utilities and independent power producers, to re-evaluate whether regulation of CCR under RCRA subtitle C is necessary in light of subsequent information. EPA explained that this was based on several

[17] US Bureau of Reclamation (USBR), "Water Operation and Maintenance Bulletin No. 222," Denver, Colorado, December 2007.

[18] *http://www.oregon.gov/odot/hwy/bridge/docs/bddm/pdfs/psha.pdf.*

[19] Canadian Dam Association. Canadian Dam Safety Guidelines, 2007, 88 pp.

[20] Sonmez, H., 2003. Modification of the liquefaction potential index and liquefaction susceptibility mapping for a liquefaction-prone area (Inegol, Turkey), Env. Geology, (44): 862–871.

[21] Seed, R.B., Cetin, O.K., Moss, R.E.S., Kammerer, A.M., Wu, J., Pestana, J.M., Riemer, M.F., Sancio, R.B., Bray, J.D., Kayen, R.E., Faris, A., 2003. Recent advances in soil liquefaction engineering: a unified and consistent framework, 26th annual ASCE L.A. Geot. Spring Sem., Long Beach, California, April 30, 71 pp.

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relatively recent developments, such as a newly completed quantitative risk assessment that concluded that the disposal of CCR in unlined waste management units posed substantial risks, with upper end risk estimates ranging from $10^{-2}$–$10^{-4}$. Citing to the recent structural failures of surface impoundments, the proposed rule also noted that these wastes have caused greater damage to human health and the environment than EPA originally estimated. Finally, EPA explained that recently collected information regarding the existing state regulatory programs had called into question whether those programs, in the absence of national minimum standards specific to these wastes, had sufficiently improved to address the gaps originally identified in the May 2000 Regulatory Determination. EPA ultimately concluded that federal regulation of this material was necessary, but did not reach any conclusion as to whether regulation under subtitle D would be sufficient or whether regulation under subtitle C would be necessary to adequately address the risks.

Of the over 450,000 comments received on the proposed rule, the vast majority focused on whether the Bevill exemption should be retained, and the corresponding question of whether CCR regulations should be established under RCRA subtitle C or subtitle D. In terms of the sheer numbers, the majority of commenters supported a decision to revoke the Bevill exemption and to regulate CCR under a subtitle C rule. These commenters, largely individual members of the public and environmental groups, generally argued that the Bevill exemption should be revoked because state programs have failed to adequately regulate the disposal of CCR and because the risks associated with the management of these wastes are significant. In support of both points, these commenters pointed to the fact that the number of damage cases that have been discovered has increased substantially since the original 2000 Regulatory Determination, and have continued to grow since publication of the proposed rule in 2010.

By contrast, state organizations, individual states, and industry groups (electric utilities, recycling firms, trade associations), largely favored a subtitle D rule. Overall, these commenters raised concern about the costs of the subtitle C regime, arguing that the subtitle C requirements were more stringent than necessary to address the risks from CCR disposal. Commenters also raised concern that regulation of these wastes under subtitle C would negatively affect the beneficial use of these materials, arguing that the stigma associated with regulating the disposal of CCR as a hazardous waste would "cripple" the current beneficial reuse market. Many of these commenters also argued that EPA lacks the legal authority to regulate these wastes under subtitle C on a variety of grounds, including claims that EPA entirely lacks the authority to revisit its Bevill Regulatory Determination, and that EPA had failed to comply with statutory procedures in doing so.

*A. Deferral of a Final Decision on the Bevill Regulatory Determination for CCR Destined for Disposal*

In determining whether the Bevill exemption should be retained for CCR, EPA must evaluate and weigh eight factors that were enumerated in section 8002(n) of RCRA. 42 U.S.C. 6921(b)(3)(C). The eight factors are: (1) The source and volumes of CCR generated per year; (2) present disposal and utilization practices; (3) potential danger, if any, to human health or the environment from the disposal and reuse of CCR; (4) documented cases in which danger to human health or the environment from surface run-off or leachate has been proved; (5) alternatives to current disposal methods; (6) the cost of such alternative disposal methods; (7) the impact of those alternatives on the use of coal and other natural resources; and (8) the current and potential utilization of CCR. 42 U.S.C. 6982(n).

EPA addressed each of these study factors in the 1988 and 1999 Reports to Congress, and in reaching our decisions in the August 1993 and the May 2000 Regulatory Determinations to maintain the Bevill exemption for CCR. 58 FR 42466 (August 9, 1993); 65 FR 32214 (May 22, 2000). Consequently, in considering whether to reverse these Regulatory Determinations for CCR destined for disposal, EPA reexamined the RCRA section 8002(n) study factors against all of the available data, which included both the data that formed the basis for the May 2000 Regulatory Determination and the most recent data available. (See 75 FR 35150–35156.)

As discussed at length in the proposed rule, three of these factors weighed the most heavily in the Agency's decision to reconsider its previous Regulatory Determinations. (See 75 FR 35133 and 35156–35158.) The first of these related to the extent of the risks posed by the current management of these wastes. Since the 2000 Regulatory Determination, EPA had completed a quantitative risk assessment that estimated significant risks to human health and the environment. EPA's 2010 CCR risk assessment estimated the cancer risk from arsenic that leaches into groundwater from CCR managed in units without composite liners to exceed EPA's typical risk thresholds of $10^{-4}$ to $10^{-6}$. For example, depending on various assumptions about disposal practices (*e.g.,* whether CCR is co-disposed with coal refuse), groundwater interception and arsenic speciation, the 90th percentile risks from unlined surface impoundments ranged from $2 \times 10^{-3}$ to $1 \times 10^{-4}$. The risks from clay lined surface impoundments ranged from $7 \times 10^{-2}$ to $4 \times 10^{-5}$. Similarly, estimated risks from unlined landfills ranged from $5 \times 10^{-4}$ to $3 \times 10^{-6}$, and from $2 \times 10^{-4}$ to $5 \times 10^{-9}$ for clay-lined landfills. EPA's risk assessment also estimated Hazard Quotients (HQs)[22] above 1 for other metals, including selenium and lead in unlined and clay-lined units. However, a number of technical questions were raised regarding this quantitative risk assessment that called into question the accuracy of these risk estimates.

A second and equally significant consideration related to how effectively state regulatory programs address the risks associated with the improper management of these wastes. The existing reports on state regulatory programs had called into question whether the trend in improving state regulatory regimes that EPA identified in May 2000 had materialized to the degree anticipated in the Regulatory Determination. EPA noted concern about the lack of substantial details regarding the full extent of state regulatory authority over the disposal of these materials, and the manner in which states have, in practice, implemented this oversight.

The final consideration, which is tightly related to the first two, was the recent information documenting continued instances involving the contamination of ground or surface water from the management of these wastes. Since the 2000 Regulatory Determination EPA had gathered or received information on 67 "proven or potential" cases involving damage to (*i.e.,* contamination of) ground and surface water, and to human health and the environment from improper management of CCR in landfills and surface impoundments. These also included cases involving the structural failure of surface impoundments and the catastrophic release of CCR.

[22] For more information on HQs please see Unit X. Risk Assessment of this preamble.

For each of these key areas, EPA identified a number of issues on which the absence of critical information prevented the Agency from reaching an initial decision on whether to revise the Bevill Determination. Some of these issues or uncertainties have been resolved during the development of the final rule, either as a result of information received from commenters or through additional information and analyses EPA obtained or developed, which were held out for comment in subsequent NODAs. See 75 FR 35128 (October 21, 2010) and 78 FR 46940 (August 2, 2013). However, as discussed in more detail below, critical information necessary to make a final Regulatory Determination is still lacking in two of these three areas. This information bears directly on the extent and magnitude of the risks over the course of the next several years, and the degree to which those risks can be managed sufficiently under each of the two regulatory structures available to the Agency. In the absence of this information, EPA is unable to reach a conclusion on the issue that is central to a Bevill Determination: Whether the risks presented by management of CCR waste streams can only be adequately mitigated through regulation under RCRA subtitle C. As a consequence, EPA is deferring a final Regulatory Determination for these wastes.[23]

Nevertheless, the record is clear that current management of these wastes can present, and in many cases has presented, significant risks to human health and the environment. Although EPA cannot reach conclusions as to the full extent or magnitude of those risks over the long term, the current level of risk clearly warrants the issuance of federal standards to ensure consistent management practices and a national minimum level of safety.

In the following sections, EPA describes the information that was obtained over the course of the rulemaking relating to each area of concern, and the extent to which the new information addressed the issue.

[23] Because EPA is deferring its final Bevill Determination, EPA has not responded to comments that pertain exclusively to that issue. However EPA has responded to significant comments that relate to topics that are otherwise relevant to the final subtitle D regulation. For example, because EPA is relying on the damage cases to support certain aspects of the technical requirements, EPA has responded to comments relating to the accuracy of the facts involved in the damage cases. EPA has not, however, responded to many comments on state programs because the Agency has made no final conclusions on the adequacy of those programs and is not relying on state programs to support any of the final rule's provisions.

1. Risks Posed by Current Management of CCR and Potential Danger to Human Health From the Disposal of CCR

In the proposed rule, EPA specifically noted that several uncertainties remained in the Agency's quantitative risk analysis of the current management of CCR. Chief among these uncertainties was the evolving character and composition of CCR due to electric utility upgrades and retrofits of multi-pollutant controls needed to comply with the emerging Clean Air Act (CAA) requirements, which could present new or otherwise unforeseen contaminant issues (*e.g.,* addition of calcium bromide to coal prior to combustion increasing mercury capture; use of selective catalytic reduction for post-$NO_X$ controls forming hexavalent chromium). As EPA explained, changes to fly ash and other types of CCR is expected to occur as a result of increased use and application of advanced air pollution control technologies in coal-fired power plants. These technologies include flue gas desulfurization (FGD) systems for $SO_2$ control, selective catalytic reduction (SCR) systems for $NO_X$ control, and activated carbon injection (ACI) systems for mercury control. These technologies are being installed or are expected to be installed in response to federal regulations, state regulations, legal consent decrees, and voluntary actions taken by industry to adopt more stringent air pollution controls. Use of these more advanced air pollution control technologies reduces air emissions of metals and other pollutants in the flue gas of a coal-fired power plant by capturing and transferring the pollutants to the fly ash and other air pollution control residues. Previous EPA studies of whether increased pollutant content would increase the risks correspondingly were inconclusive. For example, EPA evaluated the environmental fate of metals that are captured in CCR through use of enhanced air pollution controls, by characterizing the leaching behavior of 73 air pollution control residues, using the Leaching Environmental Assessment Framework (LEAF) methodology. Materials were tested over the pH conditions and liquid/solid ratios expected during management via land disposal or beneficial use. Leachate concentrations for most metals were highly variable over a range of coal type, facility configurations, and air pollution control residues. In addition, the data showed significantly different leaching behavior for similar residue types and facility configurations. Overall, the variability in leaching of the metals in the CCR was greater than the variability in totals concentrations by several orders of magnitude, suggesting that total pollutant content may not be predictive of leaching behavior, and consequently the risks.[24]

The Agency received no data from commenters that would aid in resolving this uncertainty. To try to establish some parameters around the uncertainty, EPA attempted to develop estimates of the extent to which this issue could meaningfully affect the risks.

As an initial step, EPA focused on mercury pollution controls, as mercury levels in these wastes was an issue of particular concern in the public comments. It has been established that mercury pollution controls can affect both the mercury content and the general leaching behavior of ash (US EPA 2006, 2008, 2009). Using the limited data available, EPA attempted to evaluate the extent to which mercury controlled wastes could ultimately affect the overall risk associated with disposal of CCR.

EPA conducted a sensitivity analysis that filtered the full 2014 risk assessment results for the subset of fly ash samples generated by facilities that have currently installed ACI systems. The samples were collected from five different facilities that were either installing or evaluating an ACI system for increasing mercury capture. At each facility, samples were collected both before and after the installation of an ACI system. Ultimately the results were inconclusive, likely because of the small sample size, and EPA can draw no conclusions about the exact effects of ACI systems on the risks from CCR disposal. Nevertheless, the analysis provided some useful information. Capturing and transferring pollutants from air emission to the fly ash and other air pollution control residues would normally be expected to increase the risks associated with disposal of these wastes. EPA's analyses, however, showed only a marginal difference in risks for ash generated with or without the use of an ACI system, and in some instances the risks decreased slightly with the addition of activated carbon. The significance of these results should not be overstated—the observed decreases were not consistent and were thought to be an artifact of the relatively small number of model iterations. It is also important to remember that these results provide no information about the potential effects from the installation of

[24] Thorneloe, S, Kosson, D., Sanchez, F., Garrabrants, A.C., and Helms, G., Evaluating the Fate of Metals in Air Pollution Control Residues from Coal-Fired Power Plants, Environ. Sci. Technol. 2010, 44, 7351–7356.

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FGD systems for $SO_2$ control, or SCR systems for $NO_X$ control, any of which could also significantly affect the characteristics of the wastes. But these results also suggest that EPA should be cautious about assuming that the risks will necessarily increase as a result of the imposition of additional air pollution controls.

Other uncertainties in the risk assessment developed for the proposal related to the extent to which some sampled data with high concentrations of constituents used in the risk assessment accurately reflect coal ash leaching from landfills or surface impoundments. For example, as explained in the proposed rule, some data reflected pore water taken in the upper section of a surface impoundment where coal refuse was placed. There were acid generating conditions and high concentrations of arsenic, but the data demonstrated that the underlying coal ash neutralized the acid conditions and greatly reduced the arsenic which leached from the bottom of the impoundment. EPA also noted that much of the pore water samples and leachate data were several years old, and questions had been raised whether these data accurately reflected current management practices. Finally, EPA noted that recent research indicated that traditional leach procedures (*e.g.,* Toxicity Characteristic Leaching Procedure (TCLP) and Synthetic Precipitation Leaching Procedure (SPLP)) may underestimate the actual leach rates of toxic constituents from CCR under different field conditions.

First, regarding the question of appropriate pH conditions in CCR units, and the resulting leachate concentrations in impoundments where coal refuse was placed, EPA obtained data during the development of this rule directly relevant to this issue. A survey conducted by the Electric Power Research Institute (EPRI) in 1995 had shown that 34 percent of unlined landfills and 68 percent of unlined surface impoundments actively managed CCR with coal refuse. However, more recent data collected by EPA as part of the Clean Water Act ELG rulemaking in 2009–2010 indicates that this management practice has declined significantly to approximately five percent of current units.

EPA also obtained sufficient data to resolve concerns about the accuracy of the concentrations in pore water and leachate used in the risk assessment. EPA received a substantial amount of data on CCR chemical constituents from commenters, which included total concentrations, pore water, and leaching test results for various types of CCR, *i.e.,* bottom ash, FGD gypsum, FGD sludge, fly ash cenospheres, boiler slag, and combined waste streams. This included data from several EPRI reports, which provided field leachate results for bottom ash, fly ash, and FGD solids from a number of landfills and surface impoundments. EPA also received leachate data from the Alaska Department of Environmental Conservation, the Michigan Department of Natural Resources and Environment (MI DNRE), and from the Maryland Department of the Environment on total metals, TCLP, and SPLP results for bottom ash and fly ash. Included among these data were TCLP results for 102 CCR samples and 12 FGD gypsum samples, and two landfill leachate samples, as well as several laboratory reports on CCR leachate from 2008 through 2010. EPA also received several reports from the University of North Dakota Energy & Environmental Research Center, with leaching test results for 58 fly ash, five FGD, and four FGD gypsum samples using various leaching methods other than TCLP, and TCLP mercury results for 15 fly ash samples, as well as leaching test results for five fly ash and two bottom ash samples using 18-hr, 30-day, and 60-day leach methods, plus bulk and trace element data for five fly ash samples, two bottom ash samples, and one slag sample. (See 76 FR 63252, October 12, 2011.)

In addition to the data submitted by commenters, EPA's Office of Research and Development (ORD), in collaboration with Vanderbilt University (VU), developed additional CCR leaching data using a revised methodology, the Leaching Environmental Assessment Framework, or LEAF, consisting of four methods that evaluate leaching potential for various waste forms at different plausible pH values and liquid-solid ratios, in order to more accurately simulate leaching potential over a variety of field conditions. The LEAF methods went through validation working with 20 different laboratories, different waste matrices, and documented in two EPA reports finding good agreement between the labs for the four methods.[25] In addition, EPA compiled decades of data for ten different case studies to compare field and laboratory leach data.[26] These data also showed LEAF methods to be a good predictor of field leachate behavior using geochemical speciation modeling for factors such as oxidation that are difficult to account for in the lab. When considered along with the methods validation, the field-to-lab leachate data comparison provides additional confidence that LEAF methods can more accurately predict environmental release over a range of materials, waste form, pH, liquid-solid ratio, and other parameters influencing leaching behavior such as calcium depletion for a material.

In updating the risk assessment for the final rule, EPA relied on surface impoundment pore water data and impoundment wastewater data, including the data submitted by commenters. For landfills, EPA only used LEAF data to characterize the leachate for the range of materials resulting from various air pollution control technologies. The CCR data documented in three EPA reports[27] and summarized in Thorneloe et al, 2010[28]

[25] Garrabrants A.C., D.S. Kosson, H.A. van der Sloot, F. Sanchez and O. Hjelmar (2010) Background information for the Leaching Environmental Assessment Framework (LEAF) Test Methods, EPA–600/R–10/170, U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division, December 2010.

Garrabrants A.C., D.S. Kosson, L. Stefanski, R. DeLapp, P.F.A.B. Seignette, H.A. van der Sloot, P. Kariher and M. Baldwin (2012a) Interlaboratory Validation of the Leaching Environmental Assessment Framework (LEAF) Method 1313 and Method 1316, EPA/600/R–12/623, U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division, September 2012.

Garrabrants A.C., D.S. Kosson, R. DeLapp, P. Kariher, P.F.A.B. Seignette, H.A. van der Sloot, L. Stefanski and M. Baldwin (2012b) Interlaboratory Validation of the Leaching Environmental Assessment Framework (LEAF) Method 1314 and Method 1315, EPA–600/R–12/624, U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division, September 2012.

[26] Kosson D.S., van der Sloot, H.A., Seignette, P.F.A.B. 2014. Leaching Test Relationships, Laboratory-to-Field Comparisons and Recommendations for Leaching Evaluation using the Leaching Environmental Assessment Framework (LEAF), EPA–600/R–14/061. EPA Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC, 27711. December.

[27] Sanchez F., R. Keeney, D.S. Kosson and R. DeLapp (2006) Characterization of Mercury-Enriched Coal Combustion Residues from Electric Utilities using Enhanced Sorbents for Mercury Control, EPA–600/R–06/008, U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division, February 2006.

Sanchez F., D.S. Kosson, R. Keeney, R. DeLapp, L. Turner and P. Kariher (2008) Characterization of Coal Combustion Residues from Electric Utilities using Wet Scrubbers for Multi-pollutant Control, EPA–600/R–08/077, U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division, July 2008.

Kosson D.S., F. Sanchez, P. Kariher, L.H. Turner, R. DeLapp, and P. Seignette (2009) Characterization of Coal Combustion Residues from Electric Utilities—Leaching and Characterization Data, EPA–600/R–09/151, U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division, December 2009.

[28] Thorneloe S.A., D.S. Kosson, F. Sanchez, A.C. Garrabrants and G. Helms (2010) "Evaluating the fate of metals in air pollution control residues from coal-fired power plants," *Environmental Science and Technology,* 44, 7351–7356.

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provides a robust characterization of air pollution control residues from coal-fired power plants and indicates that leaching rates can vary by several orders of magnitude, depending on pH levels and the amount of liquid that comes into contact with the CCR solids (*i.e.,* the liquid to solid ratio).

The 2014 risk assessment incorporates these new data, and accounts for both the pH of the waste in field conditions, as well as the liquid-to-solid ratio of the leachate and CCR, which effectively addresses the concerns raised in the proposed rule that TCLP and SPLP methods could underestimate leachate concentrations.

A further area of uncertainty related to one of the primary inputs into the risk assessment. As noted in the proposed rule, the Agency's risk estimates were based on the existing cancer slope factor of 1.5 $mg/kg/d^{-1}$ for arsenic in EPA's Integrated Risk Information System (IRIS). However, EPA noted that was in the process of revaluating the arsenic cancer slope factor in light of recent recommendations from the National Research Council (NRC) of the National Academy of Sciences (NAS) in "Critical Aspects Arsenic in Drinking Water, 2001 Update." In the proposal, EPA estimated that using this NRC data analysis would increase the individual risk estimates by approximately 17 times.

EPA is currently evaluating the arsenic cancer slope factor in light of more recent NRC recommendations, regarding the approach and the science for estimating cancer and non-cancer risk in "Critical Aspects of EPA's IRIS Assessment of Inorganic Arsenic, (NRC 2013)." EPA is in the process of implementing these recommendations, but to date has been unable to finalize its IRIS reassessment. Nor did EPA receive any other information during the development of this final rule that would help to resolve this uncertainty.

A final source of uncertainty in the risk assessment developed for the proposed rule related to the potential impact from the interception of contaminated groundwater plumes by surface water bodies that exist between a waste management unit and a down-gradient drinking water well. It is common for coal-fired utilities to be located near water bodies, which are used as a source of cooling water and waste conveyancing. Releases from surface impoundments located in close proximity to water bodies can be intercepted, which can significantly affect the contaminants that reach drinking water wells. For example, surface impoundments are commonly placed next to rivers, which can intercept the leachate plume and prevent contamination of drinking water wells on the other side of the river. Also, in such circumstances the direction of groundwater flow on both sides of the river may be towards the river; thus, the drinking water well on the opposite side of a river may not be impacted.

Over the course of the rulemaking, EPA was able to obtain sufficient data to model the impact from interception of contamination by surface water bodies. The risk assessment developed for the final rule accounts for the interception of the groundwater contamination plume by surface water bodies, and the resulting decrease in constituent mass to downstream drinking water sources. As a consequence of this modeling, the median risks for surface impoundments and landfills were substantially lower than both the high-end and median risks modeled in the 2010 risk assessment, *i.e.,* by approximately an order of magnitude.

2. Adequacy of Existing State Regulatory Oversight

The assessment of state regulatory programs in the proposed rule was based largely on two reports: A joint U.S. Department of Energy (DOE) and EPA study completed in 2006, "Coal Combustion Waste Management at Landfills and Surface Impoundments, 1994–2004," and a 2009 survey conducted by the Association of State and Territorial Solid Waste Management Officials (ASTSWMO). EPA's preliminary conclusion was that while states seem to be regulating landfills to a greater extent than in 2000, significant gaps in state programs appeared to remain, particularly with respect to the oversight of surface impoundments.

In reaching this conclusion EPA noted the following findings from the DOE/EPA study: only 19 percent (three out of 19) of the surveyed surface impoundment permits included requirements addressing groundwater protection standards (*i.e.,* contaminant concentrations that cannot be exceeded) or closure/post-closure care, and only 12 percent (two out of 12) of surveyed units were required to obtain bonding or financial assurance. The EPA/DOE report also concluded that approximately 30 percent of the net disposable CCR generated was potentially exempt from all state solid waste permitting requirements (EPA/DOE Report at pp 45–46). For example, at the time of the report, Alabama did not regulate CCR disposal under any state waste authority and nor had a dam safety program. Texas (the largest coal ash producer) did not require permits for waste managed on-site, which is defined as waste managed at any site owned by the generator, up to 50 miles away from the generating facility. Finally, the report found that a number of states only regulated surface impoundments under CWA authorities, and consequently primarily addressed the risks from effluent discharges to navigable waters, but did not require liners or groundwater monitoring.

The more recent 2009 ASTSWMO survey reached similar conclusions. With respect to liner requirements, 36 percent of surveyed states did not have minimum liner requirements for CCR landfills, while 67 percent did not have CCR liner requirements for surface impoundments. Similarly, 19 percent of states surveyed did not have minimum groundwater monitoring requirements for landfills and 61percent did not have groundwater monitoring requirements for surface impoundments. The 2009 ASTSWMO survey also indicated that only 36 percent of states regulated the structural stability of surface impoundments.

In the proposal, EPA identified several issues that complicated its preliminary assessment and prevented the Agency from reaching overall conclusions as to the adequacy of state regulatory programs. First, EPA raised concern about the absence of any real details in the two reports regarding how states, in practice, oversee the disposal or other solid waste management of CCR. For example, even though the disposal units might not be regulated under the state solid waste provisions, some states may use performance based standards or implement requirements to control CCR landfills and surface impoundments under other state programs. Second, EPA noted that most of the more recent data primarily focused on the requirements applicable to new management units, which only represented approximately 10 percent of currently operating units. EPA had little, if any, information that described the extent to which states and utilities had implemented requirements, such as groundwater monitoring, on the many existing landfills and surface impoundments that receive CCR. Moreover, the information in the record for the proposal with respect to these older units was fifteen years old. EPA assumed it to be unlikely that states would have required existing units to install liners, but suggested states may have been more likely to have imposed groundwater monitoring for such units over the last 15 years.

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EPA also identified several issues that would be relevant to the Agency's evaluation of the overall adequacy of state regulatory programs. Specifically, EPA explained that it would consider how state regulatory programs have, in practice, evaluated and imposed requirements to address: (1) Leachate collection; (2) groundwater monitoring; (3) whether a unit must be lined and the type of liner needed; (4) the effectiveness of existing management units as opposed to new management units; (5) whether the state requires routine analysis of CCR; (6) whether financial responsibility requirements are in place for the management of CCR; (7) the extent of permit requirements, including under what authorities these disposal units are permitted, the types of controls that are included in permits, and the extent of oversight provided by the states, (8) whether state programs include criteria for siting new units; (9) the extent of requirements for corrective action, post-closure monitoring and maintenance; (10) the state's pattern of active enforcement and public involvement; and (11) whether or not these facilities have insurance against catastrophic failures.

EPA received a substantial amount of information on state programs from commenters. Extensive comments were submitted by a coalition of environmental groups, outlining the alleged gaps in state regulatory programs applicable to the management of CCR. These comments contained a comprehensive analysis of 37 state programs based on the findings of the DOE/EPA 2006 report as well as on an independent compilation of state program requirements. According to these commenters' analysis, only four states (representing approximately four percent of the CCR generated in the U.S. in 2005) required groundwater monitoring in all new and existing landfills, and only six states (representing approximately 19 percent of the CCR generated in 2005) required groundwater monitoring in all new and existing surface impoundments; only five states (representing approximately seven percent of the CCR generated in 2005) required composite liners for all new landfills; and only four states (representing approximately 19 percent of the CCR generated) required composite liners for all new surface impoundments. The commenters' analysis discounted any state law that included any provision that granted permit writers discretion to modify the requirement on a case-by-case basis, and/or to grant waivers and exemptions based on the waste's toxicity, onsite location, and management practice.

EPA also received comments from ASTSWMO, the Environmental Council of the States (ECOS), and 36 individual states. In its comments, ASTSWMO submitted a report with revisions of the aggregated statistics in its 2009 report, which they claim demonstrated that state CCR programs were more robust than described in the proposed rule. These commenters generally agreed with EPA's conclusion that state requirements for key CCR requirements are typically more robust for landfills than for surface impoundments. ASTSWMO's comments included the following examples: 71 percent of the surveyed states required a liner for landfills, compared to 65 percent that required that surface impoundments be lined; 87 percent of surveyed states required groundwater monitoring at landfills, compared to 67 percent of states that required groundwater monitoring at surface impoundments; and while 83 percent of surveyed states required structural stability monitoring at landfills, only 64 percent of surveyed states required it at surface impoundments. The sole exception related to permit requirements, where the report claimed that 91 percent of the surveyed states required a permit of some type for surface impoundments, as compared to 86 percent of states that required a permit for landfills. In addition, ASTSWMO claimed that all 42 surveyed states had the authority to require remediation. The report also alleged that in 43 of 44 states, states had the authority to require surface impoundments to implement repair and maintenance efforts during operation. ASTSWMO also claimed that 43 out of 44 states required that steps be taken to protect human health and the environment, and that 41 of 43 states also had authority to require closure.

According to this revised survey, state requirements also vary with respect to whether they applied to all waste units, or only to new units or lateral expansions. ASTSWMO stated that in 34 percent of the surveyed states, liner requirements applied equally to new and existing landfills, and to both existing and new surface impoundments in 46 percent of the surveyed states. Similarly, ASTSWMO stated that groundwater monitoring was required for both existing and new landfills in 82 percent of the surveyed states, and to both existing and new surface impoundments in 74 percent of the surveyed states.

Nineteen states and state organizations also directly responded to the environmental groups' report by submitting comments on their programs, although only four of these states were among the leading CCR generators: Kentucky, North Dakota, Ohio, and Michigan. These states identified specific instances where the assertions made by the environmental groups were factually incorrect or omitted relevant information. In response to both the proposed rule and the NODA (76 FR 63252, October 12, 2011) most states provided only summaries of their regulatory programs rather than detailed descriptions.

As EPA explained in the proposed rule, there are significant limitations to the kind of aggregated survey statistics presented in ASTSWMO's comments. Such statistics fail to provide the information necessary to meaningfully address the question of how, in practice, state programs regulate the relevant risks presented by the management or disposal of CCR, which was the issue that EPA explained was necessary to resolve. For example, even assuming that 91 percent of the surveyed states actually do require a permit of some type for surface impoundments, this provides no information on the nature or extent of the specific requirements in the permit. As noted in the proposal, most CCR surface impoundments are regulated under a NPDES permit, and while the risks from effluent discharges to navigable waters are addressed, these units are not subject to the provisions designed to protect groundwater, such as liners or groundwater monitoring. Nor does it address the extent of the requirement; for example, although Texas generally requires landfills to be permitted and to monitor groundwater, the majority of CCR units are exempt from these requirements because all industrial wastes managed on-site (*i.e.,* any site owned by the generator, up to 50-miles away from the generator's facility) are exempt. Finally, since the ASTSWMO survey does not identify the individual surveyed states but merely presents aggregated statistics, this information cannot be correlated with the amount of CCR generated, which significantly limits its value; for example, information demonstrating the strength of the regulatory program in a state responsible for two percent of the net CCR generated nationally is less significant than similar information on a state responsible for 25 percent of the net CCR generated.

In addition to the information provided by commenters, EPA independently reviewed state statutes and regulations, with a more detailed focus on the 16 states responsible for approximately 74 percent of the CCR generated in 2009. It is clear from this

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review, as well as from information submitted by the commenters, that the degree of state regulatory oversight of these wastes and the overall protectiveness of the particular state programs varies widely.

Overall, the information from commenters and from EPA's own review of state programs generally confirms EPA's original conclusion that significant gaps remain in many state programs. Some programs provide minimal or no regulatory oversight of CCR units. For example, Arizona, New Mexico, and Utah have no regulations applicable to CCR units or entirely exempt CCR from state regulations governing solid waste. Similarly, Mississippi, Montana, and Texas (the largest coal-ash producer) exempt the on-site disposal of CCR (as "non-hazardous industrial solid waste") from some or all key requirements, such as permits or groundwater monitoring.[29] Such exemptions would cover most of the disposal of CCR within the state, as the majority of utilities dispose of their CCR on-site. Other states, such as Florida, Indiana, Ohio and Pennsylvania, exempt CCR landfills or "monofills" from many requirements. For example, Indiana regulations consider surface impoundments that are dredged at least annually to be "storage units" that are exempt from solid waste regulations, including from corrective action requirements. Many of these states are among the leading generators of CCR wastes. In total, EPA estimates that approximately 20 percent of the net disposable CCR is entirely exempt from state regulatory oversight.

State programs that entirely exempt CCR management from regulatory oversight, however, are the exception. Most states do regulate the management of CCR to varying degrees, although the particular requirements can vary significantly. Still, some general conclusions can be drawn.

Most CCR surface impoundments are permitted exclusively under NPDES or other surface water pollution prevention programs. In these states, requirements to protect groundwater, such as liners or groundwater monitoring systems, are frequently less robust than the corresponding requirements applicable to CCR landfills.

Many state programs require that new disposal units be lined and groundwater monitoring systems installed, although many exempt existing waste units from the liner and groundwater monitoring requirements. Consequently, for newer units, the facts are less alarming: 89 percent of the 114 CCR surface impoundments constructed between 1994 and 2010 have liners, and 70 percent have composite liners. Similarly, 37 of 45 CCR surface impoundments EPA surveyed had installed groundwater monitoring systems. By contrast, 79 percent of the landfills constructed during this timeframe had installed liners, but only 58 percent were composite-lined. However the majority of the older (pre-1994) waste units still lack liners; 63 percent of older landfills have no liners and 63 percent and 24 percent of older surface impoundments have either no liners or clay liners, respectively.

Information on the extent of groundwater monitoring at older units was either unavailable, or was too unreliable to support any conclusions as to the overall number or percentage of older units with groundwater monitoring systems in most states. ASTSWMO's comments in response to the October 2011 NODA identified eight states [30] that required groundwater monitoring at existing facilities, but only a few of these states addressed this issue in their comments. EPA has some anecdotal evidence on the status of groundwater monitoring in six states, including four states that are among the leading CCR generators. In the wake of the Kingston TVA spill, groundwater monitoring wells were installed at 12 of Illinois's existing surface impoundments, almost doubling the number of monitored surface impoundments in the state. However, 55 additional surface impoundments, both active and inactive, still lack groundwater monitoring systems. In Ohio, 44 CCR units, out of a total of 57 CCR units in the state (42 surface impoundments and 15 landfills) still lack groundwater monitoring, even though all of the surface impoundments were permitted decades ago under Ohio's NPDES program. Ohio acknowledged in their comments that the extent of groundwater risks in the state is poorly documented, as 40 out of 44 unlined CCR units do not have a groundwater monitoring system. In sum, the available information is limited, but at least some of that information indicates that significant gaps remain with respect to the implementation of groundwater monitoring requirements under some state regulatory programs.

Of the states that require groundwater monitoring, most appear to require monitoring wells to be placed around the waste unit boundary, although the distance from the unit boundary varies from 50 feet to 150 meters. However, some state programs also authorize a buffer zone or a "zone of discharge," which allows the facility to defer remediation of groundwater contamination for some period of time, usually until the contaminant plume has migrated to the facility site boundary. Florida, Illinois, North Dakota, and Tennessee are among that states with such a regulatory provision. For example, under Florida regulations, primary and secondary maximum contaminant levels (MCLs) do not apply even beyond the "zone of discharge," absent a specific order by state regulatory authorities.

Most state programs allow the state regulatory authority to grant variances or exemptions for some or all of the requirements based on site-specific factors. For example, all of the following states require groundwater monitoring at CCR surface impoundments, but also authorize the regulatory authority to exempt or waive those requirements: Alabama, Florida, Georgia, Illinois, Indiana, Kentucky, North Carolina, North Dakota, Pennsylvania, and West Virginia. Contrary to the analysis presented by the environmental groups' comments, the mere fact that state law grants a permit authority the discretion to tailor requirements to account for a facility's site specific conditions does not support a conclusion that the regulatory program is necessarily inadequate. In fact, EPA noted in the proposal that one of the strengths of the subtitle C program was that, as a result of the permit process, requirements could be tailored to account for site specific conditions. Nor does the existence of a waiver process provide any evidence of actual practices; in their comments, a few states acknowledged that state law allowed for variances, but asserted that none had been requested.

To complicate matters further, several states explained that while state law does not mandate certain requirements, state regulatory authorities have, in practice, begun to require them in more recent permits. For example, several states, including Ohio, Texas, Michigan, Florida, and Kentucky, noted that recent practice was to require older disposal units to retrofit or close where they failed to meet relevant standards. Similarly, it appears that in the 16 leading CCR-generating states, 94 percent of new landfills have installed liners (either composite or clay), although only 19 percent of these state programs actually mandate CCR landfills to install a liner. And although only six percent of these state programs require installation of a liner in a new surface impoundment, 75 percent of

[29] See 30 TX ADC 335.2(d);

[30] Georgia, Illinois, Indiana, Iowa, Montana, Ohio, Pennsylvania, and South Carolina.

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new CCR surface impoundments in these states are lined.

All of this information suggests that, at least in some cases, the concerns raised in the proposal regarding the protectiveness of state programs remain warranted. But it also is clear it would be impossible to accurately evaluate whether, in practice, state programs are protective without reviewing individual permit decisions and permit requirements. Such an evaluation would necessarily involve not only a review of the specific permit requirements, but also the site conditions and other factual bases supporting the decision to impose the particular requirements. Unfortunately, this information was not provided by commenters or found in any source currently available to the Agency.

3. Documented Cases in Which Danger to Human Health or the Environment From Surface Run-off or Leachate Has Been Proved

In the proposed rule, EPA described the information it had compiled on specific cases where CCR mismanagement had caused harm to human health or the environment since the 2000 Regulatory Determination. Specifically, EPA explained that it had identified 27 proven damage cases: 17 cases of damage to groundwater, and ten cases of damage to surface water, seven of which are ecological damage cases. Sixteen of the 17 proven damage cases to groundwater involved disposal in unlined units; for the one additional unit, it is unknown whether the unit was lined. EPA also identified 40 potential damage cases to groundwater and surface water. The Agency noted that these numbers likely underestimated the number of damage cases and its expectation that additional cases of damage would be found if a more comprehensive evaluation was conducted, particularly since much of this waste has been (and continues to be) managed in unlined disposal units. EPA also noted its concern that several of the new damage cases involved activities that differ from prior damage cases, including the catastrophic release of waste due to the structural failure of CCR surface impoundments, such as the dam failures that occurred in Martins Creek, Pennsylvania and Kingston, Tennessee, as well as the large-scale placement, akin to disposal, of CCR, under the guise of "beneficial use."

EPA noted as well that it had received new reports from industry and environmental and citizen groups regarding damage cases. Industry provided information to demonstrate that many of EPA's listed proven damage cases did not meet EPA's criteria for a damage case to be considered "a proven damage case," that had been developed for purposes of the Bevill Regulatory Determinations. Environmental and citizen groups, on the other hand, had submitted reports alleging the existence of more recent damage cases beyond those EPA had previously documented.

EPA raised questions concerning the following areas associated with the damage cases; first, whether the damage cases discovered to date accurately reflected the true number of damage cases associated with the mismanagement of CCR. Second, EPA highlighted concern regarding the accuracy of the available information on damage cases, as in certain instances, much of the information was largely anecdotal. EPA therefore specifically solicited comments from state regulatory authorities and the facilities involved with the incidents, in the hope of obtaining direct evidence of the facts in each case and to obtain a better understanding of the nature of the damage caused by past and current management practices. For the same reason, on October 12, 2011, EPA published a NODA, soliciting comment on the extensive reports received during the original comment period on the proposed rule. (See 76 FR 63252.)

As discussed in more detail in Unit XI of this document, EPA received a significant number of comments on this topic, both during the original comment period on the proposal, and in response to the NODA. EPA received information on additional damage cases from a number of citizen groups, including the report from Environmental Integrity Project and Earthjustice titled, "Out of Control: Mounting Damages From Coal Ash Waste Sites," which presented information on 31 alleged CCR damage cases that were not included or were not recognized as damage cases in EPA's July 2007 report. EPA also received an August 26, 2010 report by the Environmental Integrity Project, Earthjustice, and the Sierra Club titled "In Harm's Way: Lack of Federal Coal Ash Regulations Endangers Americans and Their Environment," which presented an additional 39 alleged CCR damage cases.[31] EPA also received information on ten additional damage cases from state officials in Michigan and Wisconsin.

EPRI submitted two draft reports titled "Evaluation of Coal Combustion Product Damage Cases: Volume 1: Data Summary and Conclusions" (finalized in July 2010), and "Evaluation of Coal Combustion Product Damage Cases: Volume 2: Case Summaries" (finalized in September 2010). In these reports, EPRI provided information that, they claimed, showed that many of EPA's previously identified "proven" damage cases did not meet EPA's criteria for a damage case to be considered "proven." In response to the 2010 NODA, USWAG submitted a report that reviewed the 70 additional damage cases submitted by citizen groups as part of their comments on the proposed rule. These reports focused primarily on the degree to which the contamination had been contained "on-site" or had migrated off-site of the facility.

In Unit XI of this document, EPA discusses at length all of the comments received and its subsequent analysis of the information obtained throughout the rulemaking. In sum, after analyzing all of the information submitted in response to this rulemaking, EPA has confirmed a total of 157 cases, both proven and potential, in which CCR mismanagement has caused damage to human health and the environment. Although EPA expects that additional damage cases will be discovered in response to the installation of the groundwater monitoring systems required by the final rule, overall EPA has a significantly better understanding of the extent and nature of the damage caused by CCR mismanagement than when the proposed rule was issued. EPA has sufficient confidence in the veracity of the information collected to rely on it in making decisions in this rule.

4. Conclusions

EPA explained in the proposed rule that the decision on whether to retain the Bevill exemption is inherently discretionary, in that it ultimately requires the Agency to make a policy judgment as to the appropriate balance among the eight statutory factors. Chief among the several principles that EPA stated would guide its decision was that any action must protect human health and the environment. To this end, EPA singled out three key areas of analyses that bear directly on that guiding principle: the extent of the risks posed by mismanagement of CCR; the adequacy of state programs to ensure proper management of CCR; and the extent and nature of damage cases.

The first of these largely related to the 2010 quantitative risk assessment of the potential for contamination to

[31] EPA also received several additional reports that contained allegations of further damage cases. However, because these were submitted after the close of the comment period, EPA did not evaluate these damage cases for this rulemaking or otherwise consider the information in those reports.

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groundwater. During the rulemaking, EPA received information that allowed the Agency to resolve two of the four primary uncertainties identified in the proposal. The risk assessment has been revised with updated pore water concentration data and with LEAF leachate data, and accounts for the potential reduction of contaminants reaching drinking water sources due to interception of contamination by surface water bodies. However, two sources of uncertainty remain: the potential effect of pollution control technologies on the CCR characteristics, and the appropriate IRIS value for arsenic.

EPA's risk assessment evaluated current management practices, and generally did not attempt to account for or evaluate the potential for future changes in the wastes. While EPA has great confidence in the assessment, its ability to definitively resolve this question is therefore limited, given the very real potential for significant changes in CCR characteristics and constituents in the near future, due to the required installation of pollution control technologies. Changes in the CCR characteristics are particularly significant, as the risk assessment concluded that one of the parameters most likely to affect the agency's risk estimates was the characteristic of the wastes.

With respect to the second area, EPA is unable to reach any definitive conclusions as to whether state regulatory programs are so deficient that the level of federal oversight under subtitle C is necessary. Specifically, EPA cannot determine from the available information how states, in practice, have implemented regulatory requirements. At this point, only limited conclusions are possible.

Clear deficiencies exist in some state regulatory programs, and questions remain with respect to others. And many of these concerns exist with respect to programs in states responsible for the majority of CCR generation and disposal. However, most state programs, although they vary considerably, are not clearly deficient on their face. But it is equally clear that exclusive reliance on the regulatory programs as written, without any examination of how states have implemented those requirements in practice, would not support sweeping conclusions about the overall adequacy of state programs. It is critical to ensure that any decision accurately accounts for how the states have exercised their judgment in implementing those requirements, before concluding that state programs cannot adequately oversee the management of CCR without the degree of federal involvement mandated by subtitle C. Notwithstanding EPA's inability to draw conclusions on the overall adequacy of state programs, the high degree of variation across state programs strongly supports the need for federal requirements to establish a consistent national standard of groundwater and human health protection.

In contrast to the other two areas identified in the proposed rule, while some uncertainty remains with respect to the damage cases—namely, whether the 157 identified to date represent the total number of damage cases caused by CCR mismanagement, and whether some of the "potential" damage cases should be classified as "proven" damage cases—at this point, EPA has concluded that the available information provides a sufficient evidentiary base on which decisions can be made. In the absence of the necessary information on two of the three critical areas, however, EPA cannot reach any final conclusions regarding the appropriate balance among the eight statutory factors. Consequently, EPA is also not reaching any final conclusions as to whether a damage case is best categorized as "proven" or "potential." Such a finding is relevant only to the Bevill Regulatory Determination.

However, as discussed in more detail in Unit XI of this document, the damage cases provide extremely valuable evidence that is directly relevant to the question of whether and how to regulate CCR waste. For example, the damage cases provide "real world" evidence against which to compare EPA's risk modeling estimates, such as evidence regarding the frequency with which particular constituents leach into groundwater. They also provide direct evidence regarding specific waste management practices at electric utilities, along with the potential consequences of those practices. Finally, both the specifics of the damage cases and the fact that they continue to occur provide strong evidence of the need for this rule under subtitle D while EPA obtains the information that will allow the Agency to make a final Regulatory Determination for these wastes.

Thus, even though EPA is not able to reach a final conclusion on the Regulatory Determination for these wastes, the totality of the information in the rulemaking record clearly demonstrates that the risks associated with the current management and disposal of CCR remain substantial. EPA's risk assessment concluded that the cancer risks from unlined surface impoundments ranged from $3 \times 10^{-4}$ for trivalent arsenic to $4 \times 10^{-5}$ for pentavalent arsenic. Non-cancer risks from these same units also significantly exceeded EPA's level of concern, with estimates ranging from an HQ of 2 for thallium, to HQs [32] of 4 for molybdenum and 8 for trivalent arsenic. The risks associated with unlined landfills were also estimated to be significant, with cancer risks of $2 \times 10^{-5}$ for trivalent arsenic. It is important to note that these risk numbers are based on national disposal practices. Risks at an individual site may be even higher based on individual site conditions, waste characteristics, and management practices. EPA's risk assessment identified the potential for higher risks based on different waste pH values and management practices. Multiple constituents presented higher risks when considered in waste management units that co-dispose both ash and coal refuse at more acidic pHs or FGD wastes at more basic pHs. For example, the modeled cancer risks for the co-disposal of ash and coal refuse (pH 1.7–8.2) ranged between $10^{-3}$ for trivalent arsenic to $4 \times 10^{-4}$ for pentavalent arsenic. Non-cancer risks were similarly high, ranging between and an HQ of 13 for cobalt, and HQs of 14 for pentavalent arsenic to 26 for trivalent arsenic, based on the ingestion of contaminated drinking water. Although this management practice is declining, recent information indicates that approximately five percent of facilities continue to co-dispose of ash and coal refuse in surface impoundments.

Moreover, EPA's risk estimates are consistent with the continued damage cases compiled through this rulemaking. As further discussed in Unit XI of this document, EPA has confirmed that 157 cases of proven or potential contamination of groundwater have occurred in states across the nation since the initial Regulatory Determination. These damage cases were primarily associated with unlined units and were most frequently associated with releases of arsenic. While new units are typically constructed with composite liners, which under EPA's current risk assessment adequately mitigate the risks, older units still comprise the overwhelming majority of currently operating units. EPA's data show that approximately 63 percent of currently operating surface impoundments and landfills are unlined, and thus more prone to leach contaminants into groundwater. Analysis of the information from the damage cases also demonstrates that unlined surface

[32] For more information on HQs please see Unit X. Risk Assessment of this preamble.

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impoundments typically operate for 20 years before they begin to leak. Most of the currently operating surface impoundments are between 20 and 40 years old.

The age of the units also has implications for their structural stability and the potential for catastrophic releases. Of the approximately 735 CCR surface impoundments currently operating in the United States, a certain percentage have a great potential for loss of human life and environmental damage in the event of catastrophic failure. Based on the information collected from EPA's Assessment Program, 318 surface impoundments have either a high or significant hazard potential rating, at least 13 of which were not designed by a professional engineer. Of the total universe of surface impoundments, approximately 186 of these units were not designed by a professional engineer. Surface impoundments are generally designed to last the typical operating life of coal-fired boilers, on the order of 40 years. However, many impoundments are aging; based on the subset of units for which age data were available, approximately 195 active surface impoundments exceed 40 years of age; 56 units are older than 50 years, and 340 are between 26 and 40 years old. In recent years, problems have continued to arise from these units, which appear to be related to the aging infrastructure, and the fact that many units may be nearing the end of their useful lives. For example, as a result of the administrative consent order issued after the December 2008 spill, TVA conducted testing which showed that another dike at TVA's Kingston, Tennessee plant had significant safety deficiencies. Collectively, these facts indicate a high likelihood that in the absence of any regulatory action, such units will leak in the near future, or are currently leaking, undetected, since groundwater monitoring is not installed at many of these older units. Moreover, damage cases continue to occur; in response to EPA's CERCLA 104(e) information request letter, a total of 35 units at 25 facilities reported historical releases. These range from minor spills to a spill of 0.5 million cubic yards of water and fly ash. And as recently as February 2014, CCR slurry was released into the Dan River from an inactive surface impoundment in North Carolina.

All of which demonstrates a compelling need for a uniform system of requirements to address these risks without waiting for the information and analyses necessary to complete a final Regulatory Determination. EPA will continue to monitor these critical areas, and will provide the public with an additional opportunity to comment on any proposed Regulatory Determination, prior to issuing a final Regulatory Determination.

*B. Final Regulatory Determination Regarding Beneficial Use*

EPA generally proposed to retain the May 2000 Regulatory Determination that beneficially used CCR did not warrant federal regulation under subtitle C of RCRA. As EPA stated in the May 2000 Regulatory Determination, "In the [Report to Congress], we were not able to identify damage cases associated with these types of beneficial uses, nor do we now believe that these uses of coal combustion wastes present a significant risk to human health and the environment. While some commenters disagreed with our findings, no data or other support for the commenters' position was provided, nor was any information provided to show risk or damage associated with agricultural use. Therefore, we conclude that none of the beneficial uses of coal combustion wastes listed above pose risks of concern." (See 65 FR 32230.) EPA noted that since the original Regulatory Determination, the Agency had found no data or other information to indicate that existing efforts of states, EPA, and other federal agencies had been inadequate to address the environmental issues associated with the beneficial use of CCR that were originally identified in the Regulatory Determination. EPA explained that it had proposed this approach in recognition that some uses of CCR, such as encapsulated uses in concrete, and use as an ingredient in the manufacture of wallboard, provide benefits and raise minimal health or environmental concerns. Consequently, EPA preliminarily concluded that encapsulated uses of CCR, which are common in many consumer products, did not merit regulation based on the available information.

However, EPA noted that the issues were more difficult with respect to unencapsulated uses of CCR and specifically solicited comment on whether such uses should continue to be included as "beneficial use" under the Bevill exemption. EPA explained that unencapsulated uses have raised concerns and therefore merited closer attention. For example, the placement of unencapsulated CCR on the land, such as in road embankments or in agricultural uses, presented a set of issues similar to those that caused the Agency to propose to regulate CCR destined for disposal. But the Agency also acknowledged that the amounts and, in some cases, the manner in which CCR is used—*i.e.*, subject to engineering specifications and material requirements rather than landfilling techniques—are potentially very different from land disposal.

EPA is retaining the original 2000 Regulatory Determination for CCR that is beneficially used. EPA has made this determination based on consideration of the available information and the RCRA section 8002(n) study factors.

1. Source and Volume of CCR Generated Each Year

The American Coal Ash Association (ACAA) conducts a voluntary, annual survey of the coal-fired electric utility industry to track the quantities of CCR generated and beneficially used. According to the latest survey, the electric utility industry generated nearly 110 million tons of CCR in 2012. Approximately 39 million tons of these CCR was identified by ACAA as beneficially used in either encapsulated or unencapsulated products. An additional 12.8 million tons were placed in mine-fill operations, while the remaining 57.8 million tons were disposed of in landfills and surface impoundments (ACAA, 2013).[33]

2. Present Utilization Practices

Based on the beneficial use rates reported by ACAA, approximately 50 percent of the CCR beneficially used on an annual basis falls into two categories: (1) Fly ash used as a direct substitute for Portland cement during the production of concrete (referred to as "fly ash concrete"); and (2) FGD gypsum used as a replacement for mined gypsum in wallboard (referred to as "FGD gypsum wallboard"). Specifically, the 2012 ACAA survey indicates that the largest encapsulated beneficial uses of CCR, by more than a factor of two, are fly ash used in "concrete/concrete products/grout" (12.6 million tons) and FGD gypsum used in "gypsum panel products" (7.6 million tons).

3. Potential Danger, if Any, to Human Health or the Environment From the Reuse of CCR

The risks associated with the disposal of CCR stems from the specific nature of that activity; that is, the disposal of CCR in (often unlined) landfills or surface impoundments, with thousands, if not millions, of tons placed in a single

[33] ACAA (American Coal Ash Association). 2013. 2012 Coal Combustion Product (CCP) Production & Use Survey Report. Farmington Hills, MI 48331. Available online at: *http://www.acaa-usa.org/Portals/9/Files/PDFs/revisedFINAL2012CCPSurveyReport.pdf*

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concentrated location. And in the case of surface impoundments, the CCR is managed with water, under a hydraulic head, which promotes rapid leaching of contaminants into neighboring groundwater. The beneficial uses identified as excluded under the Bevill exemption for the most part present a significantly different risk profile.

*a. Encapsulated Beneficial Uses*

An encapsulated beneficial use is one that binds the CCR into a solid matrix that minimizes mobilization into the surrounding environment. Examples of encapsulated uses include, but are not limited to: (1) Filler or lightweight aggregate in concrete; (2) a replacement for, or raw material used in production of, cementitious components in concrete or bricks; (3) filler in plastics, rubber, and similar products; and (4) raw material in wallboard production.

Since publication of the proposal, EPA has developed a methodology for evaluating encapsulated beneficial uses. A copy of the methodology can be found at *http://www2.epa.gov/coalash/methodology-evaluating-encapsulated-beneficial-uses-coal-combustion-residuals*. EPA applied this methodology to the two largest CCR uses—the use of fly ash as a replacement for Portland cement in concrete, and the use of FGD gypsum as a replacement for mined gypsum in wallboard. A complete copy of the evaluation can be found at *http://www.epa.gov/wastes/conserve/imr/ccps/pdfs/ccr_bu_eval.pdf*.

The evaluation considered products that meet relevant physical and performance standards, that conform to standard design specifications, and that incorporate fly ash and FGD gypsum from pollution control devices currently used in the United States. Based on the findings of the evaluation, the Agency concluded that environmental releases of constituents of potential concern from CCR fly ash concrete and FGD gypsum wallboard during use by the consumer are comparable to or lower than those from analogous non-CCR products, or are at or below relevant regulatory and health-based benchmarks for human and ecological receptors.

*b. Unencapsulated Uses*

EPA acknowledged in the proposal that unencapsulated uses generally presented more difficult issues than encapsulated uses. CCR can leach toxic metals at levels of concern, so depending on the characteristics of the CCR, the amount of material placed, how it is placed, and the site conditions, there is a potential for environmental concern. However, EPA cannot extrapolate from the risk assessments conducted to evaluate the management practices associated with CCR landfills and CCR surface impoundments, because the exposure patterns are too dissimilar: The amounts and manner involved with beneficial use are very different than the thousands, if not millions of tons of CCR that are mounded in a single concentrated location in a landfill. And the potential exposures are entirely unlike surface impoundments, where CCR is managed with water under a hydraulic head, which promotes more rapid leaching of contaminants. By contrast "beneficial uses," even unencapsulated uses, are typically subject to engineering specifications, and for certain uses, federal oversight, and material requirements. For example, fly ash used as a stabilized base course in highway construction is subject to both regulatory standards under the U.S. Department of Transportation (DOT) and the Federal Highway Administration (FHWA), and engineering specifications, such as the ASTM C 593 test for compaction, the ASTM D 560 freezing and thawing test, and a seven day compressive strength above 2760 kPa (400 psi). (See 75 FR 35163–35165 for additional examples.)

In 1999, EPA conducted a risk assessment of certain agricultural uses of CCR, since this practice was considered the most likely to raise human health or environmental concerns.[34] EPA estimated the risks associated with such uses to be within the range of $1 \times 10^{-6}$. These results as well as EPA's conclusion that the use of CCR in agricultural settings was the most likely use to raise concerns, caused EPA to conclude that none of the beneficial uses identified in the 2000 Regulatory Determination warranted federal regulation, because "we were not able to identify damage cases associated with these types of beneficial uses, nor do we now believe that these uses of coal combustion wastes present a significant risk to human health or the environment." (65 FR 32230, May 22, 2000.)

EPA also noted that beneficially using secondary materials conserves natural resources, and can serve as an important alternative to disposal.

[34] For more information on this risk assessment see EPA's Notice of Regulatory Determination on Wastes from the Combustion of Fossil Fuels (65 FR 32214, May 22, 2000).

4. Documented Cases in Which Damage to Human Health or the Environment From Surface Run-off or Leachate Has Been Proved

To date, EPA has seen no evidence of damages from the encapsulated beneficial uses of CCR that EPA identified in the proposal. For example, there is wide acceptance of the use of CCR in encapsulated uses, such as wallboard, concrete, and bricks because the CCR is bound into products. However, as of the date of the proposed rule, seven proven damage cases associated with unencapsulated uses have occurred, in which large quantities of unencapsulated CCR were used indiscriminately to re-grade the landscape or to fill old quarries or gravel pits. The proposed rule discussed two of these cases. (See 75 FR 35147.) The first case was in Gambrills, Maryland and involved the disposal of fly ash and bottom ash (beginning in 1995) in two sand and gravel quarries. EPA considers this site a proven damage case, because groundwater samples from residential drinking wells near the site include heavy metals and sulfates at or above groundwater quality standards, and the state of Maryland is overseeing remediation. The second case is the Battlefield Golf Course in Chesapeake, Virginia where 1.5 million yards of fly ash were used as fill and to contour a golf course. Groundwater contamination above MCLs has been found at the edges and corners of the golf course, but not in residential wells. An EPA study in April 2010, established that residential wells near the site were not impacted by the fly ash and, therefore, EPA does not consider this site to be a proven damage case. However, due to the onsite groundwater contamination, EPA considers this site to be a potential damage case.

During the development of this final rule, EPA obtained information on a comparable situation in which large quantities of unencapsulated CCR were placed on the land in a manner that presented significant concerns. The AES coal-fired power plant in Puerto Rico lacked capacity to dispose of their CCR on-site, and off-site landfills in Puerto Rico were prohibited from accepting CCR. In lieu of transporting their CCR off of the island for disposal, AES created an aggregate ("AGREMAX") with the CCR generated at their facility, and used the aggregate as fill in housing developments and in road projects. Over two million tons of this material was used between 2004 and 2012.

Currently, there is insufficient information to determine whether groundwater has been contaminated as

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a result of this practice, and thus, EPA cannot classify this as either a proven or potential "damage case." Nevertheless, the available facts illustrate several of the significant concerns associated with unencapsulated uses. Specifically, the AGREMAX was applied without appropriate engineering controls and in volumes that far exceeded the amounts necessary for the engineering use of the materials. Inspections of some of the sites where the material had been placed showed use in residential areas, and to environmentally vulnerable areas, including areas close to wetlands and surface waters and over shallow, sole-source drinking water aquifers. In addition, some sites appeared to have been abandoned.

Consistent with the proposed rule, EPA does not consider the practices described in this section to be beneficial use, but rather waste management that would be subject to the requirements of the final rule.

5. Alternatives to Current Disposal Methods, the Costs of Such Alternatives, and the Impact of Such Alternatives on the Use of Coal and Other Natural Resources

The beneficial use of CCR is a primary alternative to current disposal methods. And as EPA has repeatedly concluded, it is a method that, when performed correctly, can offer significant environmental benefits, including greenhouse gas (GHG) reduction, energy conservation, reduction in land disposal (along with the corresponding avoidance of potential CCR disposal impacts), and reduction in the need to mine and process virgin materials and the associated environmental impacts.

*a. Greenhouse Gas and Energy Benefits*

The beneficial use of CCR reduces energy consumption and GHG emissions in a number of ways. Three of the most widely recognized beneficial applications of CCR are the use of coal fly ash as a substitute for Portland cement in the manufacture of concrete, the use of FGD gypsum as a substitute for mined gypsum in the manufacture of wallboard, and the use of CCR as a substitute for sand, gravel, and other materials in structural fill. Reducing the amount of cement, mined gypsum, and virgin fill produced by substituting CCR leads to large supply chain-wide reductions in energy use and GHG emissions. Specifically, the RIA estimates three-year rolling average of 53,054,246 million British thermal units (MMBtu) per year in energy savings and 11,571,116 tons per year in GHG (*i.e.,* carbon dioxide and methane) emissions reductions in 2015. This estimate is likely to underestimate the total benefits that can be achieved from all beneficial uses. Furthermore, the use of fly ash generally makes concrete stronger and more durable. This results in a longer lasting material, thereby marginally reducing the need for future cement manufacturing and corresponding avoided emissions and energy use.

*b. Benefits From Reducing the Need To Mine and Process Virgin Materials*

CCR can be substituted for many virgin materials that would otherwise have to be mined and processed for use. These virgin materials include limestone to make cement, and Portland cement to make concrete; mined gypsum to make wallboard, and aggregate, such as stone and gravel for uses in concrete and road bed. Using virgin materials for these applications requires mining and processing, which can impair wildlife habitats and disturb otherwise undeveloped land. It is beneficial to use secondary materials—provided it is done in an environmentally sound manner—that would otherwise be disposed of, rather than to mine and process virgin materials, while simultaneously reducing waste and environmental footprints. Reducing mining, processing and transport of virgin materials also conserves energy, avoids GHG emissions, and reduces impacts on communities.

*c. Benefits From Reducing the Disposal of CCR*

Beneficially using CCR instead of disposing of it in landfills and surface impoundments also reduces the need for additional landfill space and any risks associated with their disposal. In particular, the United States disposed of over 57.8 million tons of CCR in landfills and surface impoundments in 2012, which is equivalent to the space required of 20,222 quarter-acre home sites under eight feet of CCR.

As discussed in the final rule RIA, the current beneficial use of CCR as a replacement for industrial raw materials (*e.g.,* Portland cement, virgin stone aggregate, lime, gypsum) provides substantial annual life cycle environmental benefits for these industrial applications. Specifically, the three-year rolling average of environmental benefits estimated for 2015 includes: (1) 53,054,246 MMBtu per year in energy savings; (2) 1,661,900 million gallons per year in water savings; (3) 11,571,116 tons per year in GHG (*i.e.,* carbon dioxide and methane) emissions reductions; (4) 45,770 tons of criteria air pollutant (*i.e.,* $NO_X$, $SO_X$, particulate matter, and CO) emissions reductions; and (5) 3,207 pounds of toxic air pollutant (*i.e.,* mercury and lead) emissions reductions. All together, the beneficial use of CCR in 2015 is estimated to provide over $2.3 billion in annual national environmental benefits. In addition, since EPA estimates annual baseline disposal costs of approximately $2.4 billion for the just over 50 percent of tons disposed each year, current beneficial use and minefilling also result in annual material and disposal cost savings of approximately $2 billion annually.

6. Current and Potential Utilization of CCR

In 2012, nearly 36 percent (39 million tons) of CCR were beneficially used (excluding minefill operations) and nearly 12 percent (12.8 million tons) were placed in minefills. (This compares to 23 percent of CCR that were beneficially used, excluding minefilling, at the time of the May 2000 Regulatory Determination, and represents a significant increase.)

7. Conclusions

On balance, after considering all of the available information, EPA has concluded that the most appropriate approach toward beneficial use is to retain the May 2000 Regulatory Determination that regulation under subtitle C of the beneficial use of CCR is not warranted. EPA has also determined that regulation under subtitle D is generally not necessary for these beneficial uses.

As discussed in the preceding section, the most important of the section 8002(n) factors are those relating to the potential risks to human health and the environment. See *e.g., Horsehead Resource Development Co.* v. *EPA*, 16 F.3d 1246, 1258 (D.C. Cir, 1994) (Upholding EPA's interpretation that wastes resulting from the combustion of mixtures of Bevill-exempt and non-exempt wastes could only retain Bevill-exempt status so long as the combustion waste remained of low toxicity); *EDF* v. *EPA*, 852 F.2d 1316, 1328–1329 (D.C. Cir. 1988) (Overturning EPA rule that included as Bevill exempt, wastes that were not of low toxicity). EPA is adopting this Regulatory Determination in recognition that many uses of CCR, such as encapsulated uses in concrete, and use as an ingredient in the manufacture of wallboard, provide environmental benefits and raise minimal health or environmental concerns. To date, the information available does not demonstrate the existence of any risks associated with encapsulated uses of CCR that merit

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regulation under either subtitle C or subtitle D of RCRA.

While there can be some risks associated with unencapsulated uses—for example, the placement of unencapsulated CCR on the land, such as in large scale fill operations or in agricultural uses, depending on the specific site conditions—in general the amounts and, in some cases, the manner in which they are used are very different than land disposal. For example, agricultural uses involve the placement of inches rather than tons of CCR, and placement of CCR in a thin layer rather than mounded in a single concentrated location. In addition, these uses are subject to engineering specifications and materials requirements, which will limit the ultimate amount of material placed on the land.

EPA recognizes that several proven damage cases involving the large-scale placement, akin to disposal, of CCR have occurred under the guise of "beneficial use"— the "beneficial" use being the filling up of old quarries or gravel pits, or the re-grading of landscape with large quantities of CCR. EPA did not consider this type of use as a "beneficial" use in its May 2000 Regulatory Determination, and still does not consider this type of use to be covered by the exclusion. Therefore, the final rule explicitly removes these types of uses from the category of beneficial use, and from this Regulatory Determination. As discussed in the next section of this preamble, EPA has adopted criteria in the final rule to ensure that inappropriate uses that effectively are disposal will be regulated as disposal. The final rule expressly defines the placement of CCR in sand and gravel pits or quarries as disposal in a landfill. In addition, the final rule provides that the use of large volumes of CCR in restructuring landscape that does not meet specific criteria will constitute disposal.

While EPA has not definitively concluded that all unencapsulated beneficial uses are "safe," based on the current record for this rulemaking, EPA is unable to point to evidence demonstrating that the unencapsulated uses subject to this Determination warrant federal regulation. While the absence of demonstrated harm in this instance is not proof of safety, neither is the lack of information proof of risk.[35]

In this regard, EPA notes that many states have developed beneficial use programs that allow the use of CCR, provided they are demonstrated to be non-hazardous materials; and many require a site specific assessment before authorizing placement on the land of large amounts of unencapsulated CCR. For example, Wisconsin's Department of Natural Resources has developed a regulation (NR 538 Wis. Adm. Code), which includes a five-category system to allow for the beneficial use of industrial by-products, including coal ash, provided they meet the specified criteria. In addition, the ASTSWMO 2006 Beneficial Use Survey Report states that a total of 34 of the 40 reporting states, or 85 percent, indicated they had either formal or informal decision-making processes or beneficial use programs relating to the use of solid wastes. (*http://www.astswmo.org/Files/Policies_and_Publications/Solid_Waste/2007BUSurveyReport11-30-07.pdf*) [36] Because EPA has not identified significant risks associated with the beneficial uses covered by this Regulatory Determination, the adequacy of these state programs does not factor into EPA's Determination. Nevertheless, to the extent that that these materials do have the potential to pose risk at an individual site, the fact that many states exercise regulatory oversight of these materials provides an additional level of assurance.

Finally, EPA does not wish to inhibit or eliminate the measurable environmental and economic benefits derived from the use of this valuable material given the current lack of evidence affirmatively demonstrating an environmental or health risk. Consequently, EPA is confident that the combination of the final rule, EPA guidance, current industrial standards and practices, and in many cases, state regulatory oversight is sufficient to address concerns associated with the beneficial uses to which this Determination applies.

## V. Development of the Final Rule—RCRA Subtitle D Regulatory Approach

As previously discussed in Unit II of this document, the authority to develop and promulgate the national minimum criteria governing the disposal of CCR in landfills and surface impoundments is found under the provisions of sections 1008(a), 4004, and 4005(a) of RCRA (*i.e.*, subtitle D of RCRA). These authorities, however, do not provide EPA with the ability to issue permits, require states to issue permits, approve state programs to operate in lieu of the federal program, or to enforce any of the requirements addressing the disposal of CCR. Consequently, EPA designed the proposed RCRA subtitle D option to ensure that the requirements will effectively protect human health and the environment within those limitations. The final rule establishes self-implementing requirements—primarily performance standards—that owners or operators of regulated units can implement without any interaction with regulatory officials.

In developing the subtitle D option for the proposal, EPA considered a number of existing programs as relevant models. EPA drew most heavily on the existing 40 CFR part 258 program applicable to MSWLFs. While this program does not address CCR disposal in surface impoundments, it provided EPA with a general regulatory framework that addressed all aspects of disposal in certain land-based units. Given the Agency's expansive history and experience with these requirements, EPA concluded that the part 258 criteria with certain modifications for other land-based disposal units (*i.e.*, surface impoundments) represented a reasonable balance between ensuring the protection of human health and the environment from the risk of CCR disposal and the absence of any regulatory oversight. (See 75 FR 35192–35195.)

EPA also considered that many of the technical requirements developed to specifically address the risks from the disposal of CCR as part of the subtitle C alternative would be equally justified under a RCRA subtitle D regulatory regime. The factual record—*i.e.*, the risk analysis and the damage cases—supporting such requirements was the same, irrespective of the statutory authority under which the Agency was operating. Thus, several of the provisions under RCRA subtitle D either corresponded to the proposal under RCRA subtitle C, or were modeled after the existing subtitle C requirements; for example, EPA proposed the same MSHA-based structural stability standards for surface impoundments under the subtitle C and subtitle D options. However, because there is no corresponding guaranteed permit mechanism under the RCRA subtitle D requirements, EPA also considered the 40 CFR part 265 interim status requirements for hazardous waste facilities, which were designed to operate in the absence of a permit. These requirements were particularly

[35] The Agency is currently developing a Framework to address the risks associated with the beneficial use of unencapsulated materials. This Framework is expected to be finalized in 2015. See Unit VI of this document for more information.

[36] EPA has worked with the states to support the development of a national database on state beneficial use determinations. Information on the beneficial use determination database can be found on the Northeast Waste Management Officials' Association (NEWMOA) Web site at *http://www.newmoa.org/solidwaste/bud.cfm*. This database helps states share information on beneficial use decisions providing for more consistent and informed decisions.

relevant in developing the requirements for surface impoundments since such units are not regulated under 40 CFR part 258. Beyond their self-implementing design, these requirements provided a useful model because, based on decades of experience in implementing these requirements, EPA had assurance that these requirements were protective for a variety of waste, under a wide variety of site conditions.

In an effort to ensure that the proposed RCRA subtitle D requirements would achieve the statutory standard of "*no reasonable probability of adverse effects on health and the environment*" in the absence of guaranteed regulatory oversight, EPA also proposed to require facilities to obtain third party certifications and to provide enhanced state and public notifications of actions taken to comply with the regulatory requirements. Specifically, EPA proposed that certain technical demonstrations made by the owner or operator be certified by an independent registered professional engineer or hydrologist, in order to provide verification and otherwise ensure that the provisions of the rule were properly applied. EPA also provided a regulatory definition of the term, "independent registered professional engineer or hydrologist," to identify the minimum qualifications necessary to make these certifications. While EPA acknowledged that relying upon a third party certification was not the same as relying upon a state or federal regulatory authority and was not expected to provide the same level of independence as a state permit program, the availability of meaningful third party (*i.e.*, independent) verification provided critical support that the rule would achieve the statutory standard, as it would provide at least some degree of control over a facility's discretion in implementing the rule.

As part of the notification requirements, EPA further proposed that all owners and operators create and maintain an operating record and publically accessible Web site, containing comprehensive documentation of compliance with the rule. EPA also proposed that owners or operators provide notification to the state and the public of third party certifications as well as other information documenting actions taken to comply with the technical criteria of the rule.

*A. The Self-Implementing Approach*

While the vast majority of state and industry commenters supported regulating the management of CCR under subtitle D of RCRA, a very limited number of commenters favored the proposed self-implementing option. Most commenters argued that if the Agency were to adopt the proposed subtitle D approach it would most certainly result in parallel and redundant regulatory programs for CCR in many states, creating an unworkable situation for industry, as well as the state. Some commenters argued that under this dual regulatory approach, an owner or operator of a CCR unit could conceivably be in non-compliance with both a federal requirement and an independently administered state regulatory requirement, subjecting the owner or operator to both a citizen suit enforcement action in federal court for the alleged violation and to a wholly separate enforcement action in state court for violation of the parallel state requirement. Commenters argued that this regulatory construct made no sense and would waste federal and state judicial resources and company resources, as well as possibly resulting in inconsistent federal and state court determinations with respect to an identical regulatory requirement. It also could result in duplicative federal and state penalties for essentially the same regulatory infraction.

Commenters further argued that the prescriptive one-size-fits-all approach was overly stringent and inflexible and had the potential to greatly disrupt implementation of a state's regulatory programs, which have been tailored to provide for site specific conditions and situations. Moreover, commenters argued that because of the many state regulatory programs addressing CCR disposal, there would be many instances where state requirements could be in conflict with, in addition to, or separate from the federal requirements and it was unclear how these differences would be resolved.

Many commenters simply argued that a permitting program similar to that for MSWLFs was the only viable approach for the regulation of CCR. A significant number of commenters, however, proposed various alternative approaches for regulating CCR disposal under subtitle D of RCRA. One option would have EPA allow qualified state programs to directly administer the subtitle D requirements for CCR when the state regulatory program meets or exceeds the federal requirements, thereby minimizing duplicative regulations and avoiding the self-implementing "one size fits all" approach contained in EPA's proposal. This option, commenters reasoned, could be implemented utilizing a process developed by the Agency for evaluating whether the state's CCR regulations were equivalent to the federal minimum criteria (much like EPA does now in the case of MSWLFs under 40 CFR part 258). Another suggested approach involved EPA clarifying that a state can be more restrictive than the federal rule, and that where a state has a subtitle D regulatory program that is more restrictive, the state program and permitting process would take precedence over any self-implementation aspects of a final rule. (The proposed rule had simply stated that an owner or operator must comply with any other applicable federal, state, tribal or local laws or other requirements.) Commenters also proposed a third option, similar to the 40 CFR part 258 program, recognizing that EPA cannot approve state programs in this rule. Specifically, 40 CFR part 258 provides a definition for "Director of an approved state" that means they are the chief administrative officer of a state agency responsible for implementing the state permit program that is deemed to be adequate by EPA under regulations published pursuant to sections 2002 and 4005 of RCRA. The commenters suggested that the final rule adopt a similar approach by defining a "state permit program" and allowing a state permit program that met the definition to approve compliance with a specified regulatory requirement, *e.g.*, landfill design. The commenter suggested the following definition: "state permit program means a permit program implemented by a state agency that adopts and implements the minimum requirements for the disposal of coal combustion residuals outlined in this final rule." The commenter claimed that such an approach should not affect enforcement through citizen suits under RCRA section 7002 or by EPA under RCRA section 7003. Taking such an approach, commenters reasoned, would allow states to utilize their own enforcement authority and not rely upon the citizen suit authority under RCRA section 7002. Furthermore, allowing states to consider alternative approaches to the technical standards may give states an incentive to adopt the minimum requirements of the final federal rule into their state permit programs.

As noted, many commenters suggested that EPA rely on the same combination of RCRA statutory authorities, *i.e.*, RCRA sections 4010(c) and 4005(c), to establish controls for CCR units that it employed in promulgating federally enforceable subtitle D rules for MSWLFs and for non-MSWLFs that receive household

hazardous waste and small quantity generator waste under 40 CFR parts 257 and 258. RCRA sections 4010(c) and 4005(c), the commenters reasoned, provides EPA that authority because non-hazardous waste CCR disposal facilities have the potential to receive household wastes or conditionally exempt small quantity generator waste, whether or not such waste is actually received at the CCR disposal facility. Commenters contended that the combination of these two provisions could enable EPA to promulgate non-hazardous waste rules for CCR that could be directly administered through state permitting programs and backed up by direct EPA enforcement powers in those states that fail to adequately implement the federal rules. Such an approach, commenters concluded provides the Agency with the enforcement authority it desires under a subtitle D regulatory program, while enabling states to have a prominent role in the administration of any subtitle D rules, and preventing the duplication of potentially conflicting federal and state controls.

Finally, some commenters encouraged EPA to request from Congress the statutory authority necessary to propose non-hazardous regulations under subtitle D that could be implemented by the states and provide federal enforceability (similar to RCRA's part 258 requirements for MSWLFs). Commenters argued that states should be allowed to enforce compliance through a traditional permitting system, and that solid waste operating permits are critical to ensuring coal ash disposal facilities design, construct, operate and close their waste facilities safely. Commenters argued that permits are important because they can dictate the use of specific operating practices and control technologies that may be essential for minimizing releases. Permits also provide an important enforcement vehicle, as well as a process by which the public can be informed and participate in the siting, operation and closure of the waste disposal unit.

While the Agency appreciates commenters' attempts to craft alternative approaches to address the limitations in the proposed self-implementing subtitle D option, EPA has not "chosen" to design standards under subtitle D that are self-implementing. The sections of RCRA that are currently applicable to CCR—sections 1008(a), 4004(a), and 4005(a)—only authorize the Agency to establish minimum national criteria that apply to "facilities."

As previously discussed, these provisions do not authorize EPA to require that facilities obtain a permit from EPA or a state. The fact that section 4004(a) does not contain any provision that either expressly requires a permit to manage waste, such as in section 3005, or that requires states to adopt a permit program, such as in section 4004(c)(1), provides strong evidence that Congress did not authorize EPA to impose such a requirement on facilities managing solid waste. Compare 42 U.S.C. 6925(a), 6944(a), and 6945(c)(1). This is further confirmed by the fact that Congress thought it necessary to expressly add provisions to require state permit programs in 4010(c) and 4005(c). And the fact that the HSWA provisions are limited to two specifically enumerated types of units provides further evidence that Congress intended to authorize EPA to require permits only for these units.

The restriction that the criteria apply only to "facilities" also means that EPA cannot establish any requirements on states or state programs, either directly or indirectly. This means, for example, that EPA cannot adopt a regulation that restricts certain provisions to those "state permit programs" that meet EPA requirements, as one commenter suggested, since this would indirectly regulate state programs—leaving aside that EPA never proposed anything of the sort. This also means that EPA cannot require a facility to obtain state approval, as this not only presupposes the existence of a state permit program, but also that the state will approve the facility action on the basis of EPA's criteria. EPA cannot condition a facility's compliance on actions beyond its control.

However, these provisions restrict EPA's authority only. The legislation is clear that these are minimum requirements only, and without preemptive effect; states may therefore impose more stringent requirements, including the requirement that CCR facilities obtain a permit. This is also wholly consistent with longstanding EPA interpretations. See 44 FR 53438, 53439 (September 13, 1979) ("the standards established in the criteria constitute minimum requirements. These criteria do not preempt other state and federal requirements. Nothing in the Act precludes the imposition of additional obligations under authority of other laws on parties engaged in solid waste disposal."); see also 44 FR 45066 (July 31, 1979) ("EPA establishes only 'minimum' requirements under this portion of the Act which should not prevent States from developing broader programs or stricter standards under authority of State law."). States may also incorporate the federal requirements into state law—whether through revisions to existing legislation or regulation, or through incorporating them into any permits issued to CCR facilities. Such an approach would also resolve commenters' concerns about the potential for "parallel and redundant regulatory programs."

While subtitle C and 4005(c) provide for state oversight on rule implementation and allow approved state requirements to operate in lieu of federal criteria, the Agency lacks the authority to do so under the subsections of RCRA currently applicable to CCR. The provisions applicable to solid waste—sections 1008(a)(3), 4003, 4004(a) and 4005(a)—establish a regulatory structure that differs in key respects from those established under subtitle C and for MSWLFs under section 4005(c). Under subtitle C and section 4005(c), Congress required EPA to establish federal criteria that will serve as national minimum standards, which is comparable to the authority under section 4004(a). But subtitle C and section 4005(c) also include detailed provisions governing both the state implementation of those requirements and the relationship between the federal requirements and the state programs that implement them. No comparable provisions appear in either section 4004(a) or section 4003, which governs the approval of state SWMPs. And the consequences of these omissions are significant.

Subtitle C of RCRA contains several provisions that establish the relationship between the federal program and state requirements; these include provisions authorizing EPA to approve state programs and to retain a direct role in the implementation of the federal minimum requirements, whether through continued oversight of state implementation or direct implementation of the regulations. See, 42 U.S.C. 6926, 6928(a)(2), and 6929. For purposes of this issue, the most critical of these is the explicit direction in section 3006 that authorized state programs "operate in lieu of the Federal program." 42 U.S.C. 6926(b), (c)(1). See also 42 U.S.C. 6929 (prohibiting the adoption of less stringent state requirements than those in EPA regulations, and authorizing states to establish more stringent requirements).

The provisions for MSWLFs under section 4005(c) are less detailed, but establish a similar regulatory structure. Section 4005(c)(1) expressly directs the states to "adopt and implement a permit program or other system of prior approval and conditions," for covered

facilities in order to implement federal requirements established for such facilities. 42 U.S.C. 6945(c)(1). The statute directs EPA to determine the adequacy of such programs, and directs EPA to enforce the federal requirements in states that have not adopted an adequate program. 42 U.S.C. 6945(c)(1)(C), (2). While less detailed than the provisions under subtitle C, section 4005(c) establishes a system that is equally predicated on mandated implementation by a state regulatory authority of the federal requirements, rather than the potential coexistence of two separate regulatory systems.

The absence of any similar provisions in the "solid waste" provisions of subtitle D demonstrates that Congress intended to create a different regulatory structure. EPA's role under sections 1008(a)(3) and 4004(a) is to establish minimum criteria to determine which facilities "shall be classified as sanitary landfills and which shall be classified as open dumps," and to encourage states to use the criteria as a part of their solid waste management planning. Under this regulatory structure, Congress intended that the federal requirements apply directly to facilities and operate independent of state involvement, unless *the state* chooses to do otherwise. The ability to approve state SWMPs under section 4003 does not alter this relationship. Indeed, the fact that Congress thought it necessary to revise section 4005 to include the specific provisions in subsection (c) confirms that Congress did not believe such authority already existed under sections 4003 and 4004.

Approval of a state's SWMP pursuant to section 4003 qualifies the state to receive federal funds (no longer available) and authorizes the state to issue compliance schedules; but unlike under section 3006 or 4005(c), an authorized plan does not affect the federal minimum standards themselves, or authorize states to do so. Section 4003 contains nothing that explicitly or implicitly authorizes state requirements to operate "in lieu of" the federal requirement as a consequence of EPA approval of the state plan. The closest analogue is that states with an approved plan may establish a "timetable or schedule" to bring existing open dumps into compliance with the federal requirements; but notably, Congress only authorized the state to modify the timeframes by which such facilities must be in compliance, not the substantive requirements themselves. 42 U.S.C. 6945(a).

The combination of this regulatory structure and the need to demonstrate that the final rule achieves section 4004(a)'s protectiveness standard based on the record at the time the rule is promulgated also effectively limits EPA's ability to establish the kind of regulatory provisions commenters have requested (*i.e.*, establish an alternative that allows a state permit program to approve a less stringent technical requirement based on site specific conditions). Because as discussed in Unit IV of this document, EPA is currently unable to reach a conclusion regarding the adequacy of state programs, EPA cannot demonstrate that such an alternative would meet the section 4004(a) standard. And in the absence of a mandatory mechanism for subsequent public involvement and review, which would create decisions with their own record, subject to judicial review in their own right, the lack of such information is dispositive.

With respect to the proposal to rely on RCRA sections 4010(c) and 4005(c) authorities, EPA also disagrees that this is a viable option. As the comment appears to acknowledge, construing sections 4010(c) and 4005(c) to apply to CCR units on the basis that they could *potentially* receive conditionally-exempt small quantity generator waste is inconsistent with EPA's longstanding interpretation of those sections. EPA directly addressed this issue nearly 20 years ago in the preamble for EPA's final rules at 40 CFR part 257, subpart B. In that discussion which we summarize in the next several paragraphs, EPA explained that the proposed rule was written to provide that only those non-municipal non-hazardous waste disposal units which meet the requirements in §§ 257.5 through 257.30 "may receive" CESQG waste, as required by RCRA section 4010(c). Any non-municipal non-hazardous waste disposal unit that did not meet the proposed requirements may not receive CESQG hazardous wastes. The proposal was written to apply to non-municipal non-hazardous waste disposal units that receive CESQG waste for storage, treatment, or disposal, including such units as surface impoundments, landfills, land application units and waste piles. The regulatory definition of the term "disposal" cover all placement of wastes on the land. See 40 CFR 257.2.

EPA further noted that several commenters addressed the Agency's interpretation of the statutory language "may receive." One commenter supported the Agency's decision to limit the proposed regulatory requirements to only those non-municipal non-hazardous waste disposal units that receive CESQG wastes. Another commenter, however, stated that a closer reading of section 4010(c) reveals that Congress was not only concerned about modifying the criteria for "facilities that may receive hazardous household wastes or hazardous wastes from small quantity generators . . ." but also for "facilities potentially receiving such wastes." According to the commenter, the "may receive" clause of the first sentence in section 4010(c) merely refers to whether a facility may legally receive CESQG waste for disposal. The "potentially receiving such wastes" clause of the third sentence of Section 4010(c) refers to the actual potential for such facilities to receive CESQG wastes. The potential for CESQG waste to be disposed of at many types of industrial D landfills is high even with the proposed prohibition under § 261.5. It is the "potentially receiving" clause that specifically commands the Agency to promulgate provisions for all industrial facilities that could potentially receive CESQG wastes.

EPA disagreed with the commenter's interpretation of the statutory language in RCRA section 4010(c). More specifically, for a number of reasons, the Agency did not believe that the statutory language cited by the commenter evidenced congressional intent that the revised criteria promulgated in the rule should address disposal of solid waste in all industrial disposal facilities. First, EPA believed that the commenter erred by focusing only on the "facilities potentially receiving" language in the last sentence of section 4010(c). If one reviews this language together with the statutory language in RCRA section 4010(a), it is clear that Congress did not intend for the revised criteria being promulgated in this rule to apply to all industrial landfills.

RCRA section 4010(a) required EPA to conduct a study of the then existing guidelines and criteria issued under RCRA sections 1008 and 4004 which were applicable to "solid waste management and disposal facilities, including, but not limited to landfills and surface impoundments." 42 U.S.C. 6949a(a). This statutory language does indeed suggest that EPA was to study a wide range of solid waste disposal facilities, including industrial landfills. (As the commenter stated, because the information on industrial disposal facilities was quite limited, EPA's report to Congress did focus on municipal landfills.)

However, the statutory language in section 4010(c) directing EPA to promulgate a rule revising the criteria in 40 CFR part 257 limits the rule's applicability only to those facilities which may receive hazardous

household waste or small quantity generator waste. 42 U.S.C. 6949a(c). If Congress had intended the revised criteria under section 4010(c) to apply to all solid waste disposal facilities, including industrial landfills and surface impoundments, it clearly could have done so by enacting language similar to that already used in section 4010(a).

Secondly, the legislative history of RCRA section 4010 suggests that Congress expressly rejected a provision that would have required rules to be promulgated under section 4010(c) to apply to the entire universe of RCRA subtitle D solid waste disposal facilities. Indeed, the House version of section 4010 would have required EPA to promulgate revised guidelines and criteria such that they would be applicable to all "solid waste management and disposal facilities, including, but not limited to landfills and surface impoundments. . . ." H.R. 2867, section 30, 98th Cong., 1st Sess. (as introduced in the Senate on November 9, 1983). However, the Conference Committee instead adopted a Senate amendment which limited the scope of the revised criteria to those facilities that may receive hazardous household waste or small quantity generator waste. H. Rept. No. 98–1133, 98th Cong., 2d Sess., at 116–117.

Another indication that RCRA section 4010(c) was not intended to cover the entire universe of solid waste disposal facilities is the fact that subsequent to the enactment of section 4010(c) (as part of the Hazardous and Solid Waste Amendments in 1984), a number of bills were introduced in Congress which would have either authorized or required EPA to issue additional regulations that would address all disposal facilities receiving industrial waste as opposed to addressing those which may receive CESQG waste as stated in section 4010(c). See, *e.g.,* H.R. 3735, "Waste Materials Management Act of 1989," section 324 (would have required EPA to promulgate standards for the management of industrial solid waste) (Luken Bill); S. 1113, "Waste Minimization and Control Act of 1989," section 204 (would have required EPA to promulgate requirements for facilities that manage different types of industrial waste) (Baucus Bill). Neither of these provisions (although neither was enacted) would have been necessary if RCRA section 4010(c) required EPA to promulgate revised criteria for all types of industrial disposal facilities. (See 61 FR 34252, 34254–55 (July 1, 1996).)

The commenter on the proposed CCR rule makes essentially the same argument based on the same language in 4010(c) that EPA rejected in the 1996 rule. The commenter provided no legal analysis that contravenes the basis for EPA's interpretation of subtitle D. EPA thus declines to reopen or reconsider this interpretative question. EPA also notes that in any case, information in its record for this rulemaking indicates that CCR landfills or surface impoundments do not actually or potentially receive CESQG wastes.

Nevertheless, EPA recognizes that this regulatory structure gives rise to legitimate concerns about the potential for duplicative or conflicting state and federal regulatory systems. EPA has adopted measures to address these concerns within the confines of the regulatory structure that Congress established in subtitle D. First, EPA has made every effort to ensure that the final rule does not establish any requirements that truly conflict with existing state programs. To clarify, this does not mean that the requirements are necessarily the same, but rather that it is possible to comply with both federal and state requirements simultaneously. Or in other words, compliance with the more stringent standard—whether federal or state—will ensure compliance with the less stringent. Based on the comments received, EPA is aware of no example of a situation in which truly conflicting requirements will exist. Second, as discussed, these regulations do not constrain or direct state action. States can impose more stringent or different requirements, such as requiring a permit. Nor does the regulation require the state to enforce the federal requirements; even with promulgation of the final rule, the decision to bring an action under section 7002 remains entirely within the state's discretion. Third, as discussed in greater detail in Unit IX of this document, EPA has developed a number of measures to clarify the relationship between an individual state program, or particular requirements, and the federal criteria. Specifically, for those states that choose to submit a revised SWMP that incorporates the federal criteria, EPA intends to rely on the existing processes in 40 CFR part 256 relating to approval of SWMPs. EPA expects that approval of a state SWMP, while it cannot prevent a citizen group from filing a lawsuit, will carry substantial weight in any court proceeding charged with determining whether compliance with state requirements constitutes compliance with the federal criteria.

*B. Enforceability of the Subtitle D Approach*

Numerous commenters raised concern that reliance on a RCRA citizen suit as the basic enforcement mechanism to address non-compliance with the CCR requirements presents environmental justice concerns. Commenters argued that as a practical matter, this self-implementing approach would result in unenforced regulations affecting neighborhoods where environmental, legal, and technical services are unavailable or difficult to obtain. Commenters stated that it would be highly unreasonable for EPA to place the burden of enforcement of the CCR regulations on citizens, arguing that it is EPA's duty to make sure federal regulations protecting human health and the environment are enforced fairly and effectively, and that enforcement by citizen suits puts an unacceptable burden on low income populations located near these facilities. Commenters contended that environmental justice communities were the least likely to mount a serious challenge to the industry because low income people are often less well-educated, have less access to computers and internet technology, are less knowledgeable of how to access and interpret environmental data, and are the least likely to have the resources for a time consuming legal battle. Commenters argued that given the high number of damage cases in this industry, it was clear that the industry cannot police itself and neither can state governments. For these reasons, commenters asserted that the regulations and the enforcement must come from the federal level.

Conversely, other commenters were encouraged by the opportunity to enforce the rule through citizen suits, stating that it would result in very effective regulation since citizens have shown no reluctance to challenge companies that they believe are not responsibly following environmental regulations. Similarly, other commenters noted that other incentives existed to comply with the regulations, including the possibility of state and third party litigation (for both regulatory compliance and actual damages), and the requirements of investors, lenders, and insurers to demonstrate compliance with environmental requirements, *i.e.,* investors and lenders typically condition capital investments and loans on environmental compliance. Commenters also noted that incentives to comply were created by environmental insurance policies, which "invariably exclude damage claims arising from non-compliance from covered events" as well as typical corporate policies that call for

environmental compliance as a standard operating procedure.

Other commenters focused on the role of the professional engineer in the self-implementing framework, arguing that EPA is requiring the certifying professional to inappropriately take on a quasi-regulatory and enforcement role which places the certifying professional at great risk of being subject to nuisance lawsuits from project opponents, creating a scenario where some professionals may decline to be involved in such reviews. Still other commenters argued with EPA's basic premise that the RCRA subtitle D program lacks federal enforceability. Commenters contended that EPA's concerns about the lack of direct federal enforcement authority failed to recognize the significant enforcement opportunities available under existing law, namely the "imminent and substantial endangerment authority" under RCRA section 7003 to take action against any CCR unit that posed a risk to human health and the environment, as well as, the imminent and substantial endangerment authorities under CERCLA, as well as other federal authorities, including the federal Clean Water Act, to address circumstances where a CCR unit posed a threat.

EPA acknowledges that the lack of federal enforcement under Subtitle D presents challenges. However, as discussed above, issuing minimum national standards under the authority that is currently applicable to CCR (*i.e.,* subtitle D) is significantly more protective than the current federal standards in part 257 that apply to these wastes. It is more consistent with EPA's obligations under RCRA to put in place the additional protections that, based on the information currently available, are needed to protect health and the environment. As part of those requirements, EPA has developed a number of provisions designed to facilitate citizens to enforce the rule pursuant to RCRA section 7002. Chief among these is the requirement to publicly post monitoring data, along with critical documentation of facility operations, so that the public will have access to the information to monitor activities at CCR disposal facilities. Moreover, as noted elsewhere, a state seeking EPA's approval for a State SWMP would be required to conduct a public comment process to avail itself of the benefits of an EPA's approval.

EPA also agrees that the Agency retains the authority to bring an action under RCRA section 7003, as well as other statutes, when the facts support the necessary findings. However, an action under section 7003 does not enforce the requirements of this rule. Certainly, EPA believes that the failure to comply with the requirements of the rule increases the probability that an imminent and substantial endangerment may arise, but the fact that a facility has not complied with one or more of the requirements of this rule does not *per se* establish that a section 7003 order is warranted.

The Agency also acknowledges that the self-implementing frameworks could potentially place certifying professionals at risk for lawsuits; several of the performance standards in the proposed rule were adopted from part 258, which were designed to operate in the context of an approved state program, under the oversight of a state regulatory authority, rather than a purely private entity. In part due to this concern, the Agency has re-evaluated the performance standards throughout the final rule, and has revised them where necessary to ensure that the requirements are sufficiently objective and technically precise that a qualified professional engineer will be able to certify that they have been met.

### *C. Reliance on Certification by Independent Qualified Professional Engineers*

As previously discussed, the majority of commenters were highly skeptical of a regulatory approach that substituted state oversight with an owner or operator hiring a consultant or professional, *i.e.,* an independent registered professional engineer or hydrologist, to certify compliance with a federal regulatory requirement and posting that information on an internet site. More specifically, commenters were concerned that relying almost entirely on professional certifications for ensuring regulatory compliance did not seem like a reliable way to provide for protection of human health and or the environment.

As explained in Unit IV.A of this document, EPA is issuing national minimum criteria under subtitle D to put in place the technical requirements the Agency has determined are necessary to protect human health and the environment from the disposal of CCR in surface impoundments and landfills, while the Agency completes its Bevill Determination. EPA is relying on the certification in this context to partially compensate for one of the more significant limitations under the authorities currently applicable to CCR: The lack of any guaranteed regulatory oversight mechanism. However, EPA disagrees that the rules rely "almost entirely" on professional engineers to protect human health and the environment. The final rule relies on multiple mechanisms to ensure that the regulated community properly implements requirements in this rule. As one part of this multi-mechanism approach, owners or operators must obtain certifications by qualified individuals verifying that the technical provisions of the rule have been properly applied and met. However, a more significant component supporting EPA's determination that the technical requirements will achieve the level of protection required under section 4004(a) is the performance standards that the rules lay out. These standards impose specific technical requirements, and, even where they provide flexibility, will operate to significantly constrain the facility's activities and discretion. The certifications required by the rule supplement these technical requirements, and while they are important, they are not the sole mechanism ensuring regulatory compliance.

The rule also contains a number of provisions requiring the owner or operator to document their compliance with the rule's technical requirements, and to post those documents on a publically available Web site in a timely and transparent manner. The rule also requires owners or operators to notify State Directors of numerous actions, including that certified demonstrations have been completed. This transparency will facilitate citizen and state oversight and overall enforcement of the requirements. Finally, the rule establishes specific timeframes by which these actions must occur, including timeframes by which facilities must document compliance with the various technical requirements in the rule. Timeframes have been established for: (1) Technical compliance demonstrations made by the owner or operator; (2) certifications made by a qualified professional engineer verifying the technical accuracy and veracity of the compliance demonstration; (3) notifications made to the State Director; (4) submittals (*e.g.,* data, reports and other documentation) to the operating record; and (5) postings to the owner or operator's publicly accessible internet site. Further details pertaining to all of these requirements can be found in the Recordkeeping, Notification, and Posting of Information to the Internet section of the regulations published in this rule.

#### 1. Changes to the Definition of Independent Registered Professional Engineer or Hydrologist

EPA proposed to define "*independent registered professional engineer or*

*hydrologist''* to mean a scientist or engineer who is not an employee of the owner or operator of a CCR landfill or CCR surface impoundment, who has received a baccalaureate or post-graduate degree in the natural sciences or engineering, and who has sufficient training and experience in groundwater hydrology and related fields as may be demonstrated by state registration, professional certifications, or completion of accredited university programs that enable that individual to make sound professional judgment regarding the technical information for which a certification under this subpart is necessary.

Many comments were received on the definition. Some commenters agreed with the proposed definition, but most commenters argued that significant changes were needed. These changes included removing the requirement that the engineer be ''independent,'' adding the word ''qualified,'' and limiting the ability to make certifications to ''licensed'' professional engineers. Still other commenters felt that EPA should broaden the qualifications beyond a professional engineer or hydrologist, to include geologists, hydrogeologists, groundwater scientists or ''other qualified environmental professionals'' among the individuals able to certify regulatory demonstrations.

By far the issue receiving the most comment was whether the Agency should require a professional engineer to be ''independent.'' Commenters disagreed with EPA that the certification must be made by an independent registered professional engineer (*i.e.,* not an employee of the owner or operator of the CCR unit). Commenters argued that most utilities employ a number of professional engineers that typically possess the most relevant experience and knowledge about the unit, and that company-employed engineers and hydrologists were in a much better technical position to certify technical provisions of the rule were being met. Furthermore, commenters asserted that these professionals would be subject to the same state registration and licensing requirements as those not employed by the facility and would have an equally strong incentive to maintain their licenses in good standing as those that are independent of the utility. These commenters also pointed to several EPA rulemakings in which EPA allowed ''qualified'' professional engineers to make the kind of certifications contemplated by this rulemaking, without requiring that they be ''independent.'' Commenters also contended that state licensing and registration programs help to ensure that all professionals exercise proper judgment or ''independence'' regarding the operation of CCR landfills and CCR surface impoundments. Similarly, commenters claimed that a professional engineer without the required expertise would refuse to make any certifications for which they were not qualified. Some commenters suggested that EPA provide some criteria requiring demonstrated experience and training. Commenters also took issue with the fact that the definition focused entirely on groundwater hydrology and failed to include training or experience in other areas that would also be necessary to effectively certify specific technical criteria of the rule (*e.g.,* structural integrity, composite liner design).

The definition EPA proposed for ''independent registered professional engineer or hydrologist,'' focused on three components that were intended to define the minimum qualifications necessary to independently verify that a specific technical standard was met and to provide sufficient objectivity to reduce the opportunity for abuse. These components were: (1) The individual was a scientist or engineer by academic training or education; (2) the individual was not an employee of the owner or operator of the CCR unit; and (3) the individual had sufficient training in groundwater hydrology or related fields. The proposed definition did not require the individual to be a licensed professional engineer or hydrologist; instead the Agency prohibited the individual providing the certification from being an employee of the owner or operator of the CCR unit, reasoning that this requirement would provide some degree of independent verification of facility practices.[37] The Agency stated that the availability of meaningful independent verification was critical to EPA's ability to conclude that the performance standards laid out in the proposed rule would meet the RCRA section 4004 protectiveness standard.

In the course of developing this final rule, the Agency concluded that it needed to better define the connection between the technical requirements of the rule and the technical qualifications an individual must possess to certify the demonstrations being made by the owner or operator of the CCR unit. In doing so, the Agency looked for direction in the following rules, the ''Resource Conservation and Recovery Act (RCRA) Burden Reduction Initiative'' (71 FR 16826, April 4, 2006) and the ''Oil Pollution Prevention and Response; Non-Transportation-Related Onshore and Offshore Facilities rule (67 FR 47042, July 17, 2002). In both of these actions, the Agency had come to similar conclusions. First, that professional engineers, whether independent or employees of a facility, being professionals, will uphold the integrity of their profession and only certify documents that meet the prescribed regulatory requirements; and that the integrity of both the professional engineer and the professional oversight of boards licensing professional engineers are sufficient to prevent any abuses. (For an example see: 67 FR 47084, July 17, 2002.) And second, that in-house professional engineers may be the persons most familiar with the design and operation of the facility and that a restriction on in-house professional certifications might place an undue and unnecessary financial burden on owners or operators of facilities by forcing them to hire an outside engineer.

Reviewing these other regulatory actions and the Agency's rationale for making its decisions, has led the Agency to a similar conclusion with regard to this rule—that it is unnecessary to require the individual making certifications under this rule to be ''independent.'' Thus the final rule does not prohibit an employee of the facility from making the certification, provided they are a professional engineer that is licensed by a state licensing board. The personal liability of the professional engineer provides strong support for both the requirement that certifications must be performed by licensed professional engineers, and for removing the requirement that the engineer be ''independent.''

While other commenters argued that the word ''independent'' should be retained because an independent review and certification avoids any potential of conflict of interest, the Agency is convinced that an employee of a facility, who is a qualified professional engineer and who has been licensed by a state licensing board would be no more likely to be biased than a qualified professional engineer who is not an employee of the owner or operator. Moreover, it is not clear that an in-house engineer faces a greater economic temptation than an independent

[37] While the definition did not require the independent registered professional engineer or hydrologist to be licensed, the preamble did state that EPA expects that professionals in the field will have adequate incentive to provide an honest certification, given that the regulations require that the engineer not be an employee of the owner or operator of the CCR landfill or CCR surface impoundment, and that they operate under penalty of losing their license, implying that the professional was, in fact, licensed. This narrative and the title of independent registered professional engineer caused many commenters to assume that the certifiers indeed had to be licensed professional engineers. (See 75 FR 35194, June 21, 2010.)

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engineer seeking to cultivate an ongoing relationship with a client. EPA has concluded that the programs established by state licensing boards provide sufficient guarantees that a professional engineer, regardless of whether he/she is "independent" of the facility, will give a fair technical review.

As an additional protection, the Agency has re-evaluated the performance standards throughout the final rule to ensure that the requirements are sufficiently objective and technically precise that a qualified professional engineer will be able to certify that they have been met.

The Agency agrees with concerns that a professional engineer may not be qualified to address all the varied aspects of CCR landfill and CCR surface impoundment design, and has amended the definition to clarify and strengthen the qualifications of the individual authorized to certify the technical demonstrations under the rule. In the proposed rule, the Agency did not require an independent registered professional engineer to be licensed, only that they be an engineer or hydrologist who had received a baccalaureate or post graduate degree in the natural sciences with training and experience in groundwater hydrology or a related field. While the term "independent registered professional engineer or hydrologist" conveyed to some commenters that the individual was in fact "licensed," the definition in the proposal did not require it. Furthermore, as noted by commenters, the proposed definition focused primarily on hydrogeology expertise and did not include training and experience qualifications necessary to accurately certify some of the requirements being promulgated in the rule, *e.g.,* landfill and surface impoundment design and construction, structural stability assessments, analysis of unstable areas. In reviewing this proposed requirement, the Agency has determined that specifying exact qualifications and or experience for the professional engineer is neither necessary nor practical, given the range of technical specifications that will require certification. EPA has therefore adopted a more succinct requirement focused on the professional engineer's qualifications to perform the task or certification.

In making this change, the Agency was again strongly influenced by the "Resource Conservation and Recovery Act (RCRA) Burden Reduction Initiative" rule. (See 71 FR 16826, April 4, 2006.) In that rule, EPA amended the majority of RCRA provisions requiring the certification of an "independent, qualified, registered, professional engineer" to substitute the phrase, a "qualified professional engineer," reasoning that a requirement for a qualified professional engineer maintains the most important components of any certification requirement: (1) That the engineer be qualified to perform the task based on training and experience; and (2) that she or he be a professional engineer licensed to practice engineering under the title Professional Engineer which requires following a code of ethics with the potential of losing his/her license for negligence (see 71 FR 16868.)

In the "Burden Reduction Rule" the Agency concluded that a professional engineer is able to give fair and technical review because of the oversight programs established by the state licensing boards that will subject the professional engineer to penalties, including the loss of license and potential fines if certifications are provided when the facts do not warrant it. In fact, this personal liability of the professional engineer is one of the primary reasons that commenters to the "Burden Reduction Rule" supported the idea that RCRA certifications should only be done by licensed professional engineers (See 71 FR 16868.) Upon further analysis and reflection, the Agency sees no reason to deviate from the position EPA held in that rule. Despite some concerns raised by commenters that problems could occur if an owner or operator hires an engineering firm that is small, inexperienced, or operating outside of their past professional practice, the Agency continues to believe that with the protections afforded by the specific performance standards in this rule and the standards and ethics to which a qualified professional engineer is subject, situations in which an unqualified or un-licensed engineer certifies a technical demonstration will be avoided. Furthermore, it is important to reiterate that state licensing boards can investigate complaints of negligence or incompetence on the part of professional engineers, and may impose fines and other disciplinary actions, such as cease-and-desist orders or license revocation. (See 71 FR 16868.) In light of the third party oversight provided by the state licensing boards in combination with the numerous recordkeeping and recording requirements established in this rule, the Agency is confident that abuses of the certification requirements will be minimal and that human health and the environment will be protected.

The Agency wants to make it clear that qualified professional engineers can utilize a qualified team of professionals in performing the analyses that underlie these certifications. In most instances, EPA expects that the basis for certification by a qualified professional engineer will be the result of a team of professionals (*e.g.,* geologists, hydrologists, scientists and engineers) who have collectively worked together in order to provide the data and analyses necessary for the professional engineer to certify the specific demonstration.

The Agency is convinced that the change to the certification requirements to allow the use of in-house expertise will not compromise environmental safety. Professional engineers employed by a facility are more familiar with the facility's particular situation and are in a position to provide more on-site review and oversight of the activity being certified. To this end, the Agency is also requiring that the qualified professional engineer be licensed in the state in which the CCR unit is located. The Agency has made this decision for a number of reasons, but primarily because state licensing boards can provide the necessary oversight on the actions of the professional engineer and investigate complaints of negligence or incompetence as well as impose fines and other disciplinary actions such as cease-and-desist orders or license revocation. Oversight may not be as rigorous if the professional engineer is operating under a license issued from another state.

Finally, the Agency disagrees with comments that professional geologists or geoscientists should be added to the list of those professionals that have expertise and authority to certify compliance with certain RCRA subtitle D regulatory requirements. In developing this final rule, the Agency has re-considered the qualifications necessary to certify compliance with the technical requirements of the rule and is limiting compliance certifications to qualified professional engineers only. While some environmental professionals, *e.g.,* hydrologists, geologists may be qualified to make certain certifications, EPA is not convinced that hydrologists or geologists licensed by a state are held to the same standards as a professional engineer licensed by a state licensing board. For example, it is unclear that hydrologists or geologists are subject to the rigorous testing required by professional engineers or that state licensing boards can investigate complaints of negligence or incompetence. Further, professional engineers have licensing boards in all 50 states, a standard not achieved by other

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professional disciplines. Consequently, hydrologists, geologists, or other professionals may only perform analyses that underlie the certification, but it is the responsibility of a qualified professional engineer to make the actual certification.

*D. State and Public Notifications of Certifications*

To address concerns about the absence of adequate regulatory oversight under subtitle D, EPA proposed to require state and public notifications of the third party certifications, as well as other information documenting the decisions made or actions taken by the owner or operator to comply with the technical criteria in the rule. As stated in the proposal and reiterated here, the Agency cannot conclude that the regulations promulgated in this rule will ensure there is no reasonable probability of adverse effects on health or the environment unless there is a mechanism for states and citizens, as the entities responsible for enforcing the rule, to effectively monitor or oversee its implementation. Mandated documentation and transparency of the owner or operator's actions to comply with the rule provides this mechanism, and will help to minimize the potential for abuse. The proposal specified that the documentation of how the various technical standards had been met were to be placed in the facility's operating record, along with notification to the appropriate state authority. Additionally, EPA proposed to require the owner or operator to maintain a Web site available to the public that would also provide access to this documentation. EPA proposed that owners or operators post notices and relevant information on the internet site with a link clearly identified as being a link to notifications, reports, and demonstrations required under the regulations. While EPA recognized that the internet is currently the most widely accessible means for gathering and disseminating information, the Agency also solicited comments regarding alternative methods to provide notifications to the public and the states. The Agency also solicited comment on whether to require the establishment of a publicly accessible internet site to provide regulatory information to the public and the states, including whether there could be homeland security implications associated with internet posting of information, and whether the posting would duplicate information that is already available to the public through the state.

In response to most of these proposals, the Agency received little comment. Significant comment, however, was received on the publicly accessible internet site. Commenters argued that absent specific statutory authorization, it was inappropriate for EPA to delegate a regulatory oversight function to the regulated community by requiring the creation of a Web site and posting of regulatory compliance information. Commenters identified at least three substantial problems associated with "outsourcing information management responsibilities" to CCR facilities. First, commenters argued that EPA lacked the authority to impose such a requirement. Specifically, the commenters alleged that no statute authorizes EPA to demand that private parties act as an information clearinghouse for information pertaining to EPA's regulatory functions, either generally or in the specific context of CCR. To the contrary, the commenters argued, public information access statutes, such as the Freedom of Information Act are predicated on an assumption that information held by the government is presumptively public, while information held by a private entity presumptively is not.

Second, some commenters were concerned that facilities would not post information the facility deems to be confidential (*e.g.,* the structural stability of ash pond impoundments) and by attempting to outsource the information management role to industry, EPA effectively allows industry to make the initial determination as to confidentiality and places the burden on citizens and EPA to take action to compel disclosure.

Third, commenters were concerned that citizen groups would not accept an electric utility's self-reported information, regardless of the amount of effort the facility exerts to ensure the accuracy of the information, without a regulatory agency acting as the intermediary or providing some degree of oversight (*e.g.,* EPA's Toxic Release Inventory, EPA's Biennial Report of hazardous waste facilities). By requiring citizen groups to obtain their information from industry instead of a regulator, the commenters argued that EPA is inviting conflict as to the adequacy of data and the sufficiency of the utilities' responses to citizen groups' requests for clarification or additional information. The fact that the industry has provided information to a federal agency, subject to criminal penalties for providing false information, provides a useful public assurance of the integrity of the information.

Other commenters stated that the proposed requirement to maintain a Web site was excessive, and generated a regulatory burden upon companies that serves no useful function. Commenters urged that the same purpose could be served simply through making the certification of the registered professional engineer available on the Web site. Other commenters argued that internet posting of information on a surface impoundment's construction raised homeland security issues. These commenters alleged that the information "can be extremely sensitive and may contain information that could be used by certain individuals with an intent to destroy a dam (*e.g.,* engineering information on the structure's foundation, detailed information on physical and engineering properties, the basis for the structure hazard classification, slope stability information, etc.)."

Finally, some commenters offered an alternative to the requirement to establish and maintain a publicly accessible internet site. Under this alternative the information would be included in the owner or operator's operating record only, and persons with "legitimate interests in reviewing these data" could make a written request to the owner or operator or the permitting authority to obtain the information. The commenters alleged that this would also allow the owner, operator, and federal and state authorities to know the names and identities of all organizations requesting information on the facility, which would help protect against the misuse of these data.

EPA disagrees that RCRA section 4004(a) does not authorize EPA to require facilities to disclose all of the information required under these final rule provisions. Section 4004(a) delegates broad authority to EPA to establish criteria governing facilities' management of solid waste, requiring only that such criteria ensure that there will be no reasonable probability of adverse effects on health or the environment from the disposal of solid waste. The statute imposes no limits on the actions EPA may require facilities to perform to achieve that level of protection. Moreover, unlike other statutes, *e.g.,* the Toxic Substances Control Act, or the Federal Insecticide, Rodenticide and Fungicide Act, RCRA contains neither provisions that grant facilities the right to withhold regulatory compliance information from the public, nor provisions that establish any reasonable expectation that such information will be kept confidential. To the contrary, section 7004 explicitly provides that "[p]ublic participation in

the . . . implementation, and enforcement of any regulation under this chapter shall be provided for, encouraged, and assisted by the Administrator." 42 U.S.C. 6974(b). And in fact, this kind of information would routinely be publically available under the permitting process for hazardous waste facilities. Accordingly, RCRA provides more than ample authority to support these requirements.

As repeatedly discussed throughout this preamble, under section 4004(a) EPA must be able to demonstrate, based on the record available at the time the rule is promulgated that the final rule provisions will achieve the statutory standard. EPA explained in the proposal that a key component of EPA's support for determining that the rule achieves the statutory standard is the existence of a mechanism for states and citizens to monitor the situation, such as when groundwater monitoring shows evidence of potential contamination, so that they can determine when intervention is appropriate. The existence of effective oversight measures provides critical support for the statutory finding, particularly with respect to some of the more flexible alternatives EPA has adopted in certain of the technical standards in response to commenters' requests for greater flexibility. These "transparency" requirements serve as a key component by ensuring that the entities primarily responsible for enforcing the requirements have access to the information necessary to determine whether enforcement is warranted. Unlike a federal or state regulatory authority, private citizens cannot access a private facility to conduct inspections. While EPA encourages states to adopt and implement a CCR regulatory program, and seek EPA's approval of it via a state SWMP, EPA cannot require it. The final rule therefore must establish oversight mechanisms that will function effectively even in the absence of a state regulatory authority.

Such notifications will also reduce the incentives for owners or operators to abuse the rule's self-implementing requirements, and can improve compliance. Indeed, the public disclosure of information is an increasingly common and important regulatory tool, as evidenced by the 2010 guidance issued by the Office of Management and Budget (OMB), with principles to assist agencies in using information disclosure to achieve regulatory objectives.

Thus, even if the commenters were correct that there exists a general "presumption" that information held by private entities need not be made publically available, that presumption can be, and has been, effectively rebutted by the facts at hand.

None of the alternatives offered by the commenters would fulfill these same objectives. For example, simply making the certification of the qualified professional engineer available on the Web site without the underlying support information fails to provide the same incentives because no one could evaluate the accuracy of that certification. This alternative could also present the same concerns raised in comments on other sections of the rule, *i.e.,* that such a requirement could place the engineer at great risk of being subject to lawsuits. Requiring persons with "legitimate interests in reviewing these data" to request the data from the owner or operator also fails to provide an effective guarantee, as facilities that have failed to comply will have a strong incentive to withhold information documenting their non-compliance, however "legitimate" the request. And as noted, the absence of a guaranteed state permitting program means that requiring citizens to request information from such entities is also not a viable alternative. Given the absence of a guaranteed regulatory authority, EPA also disagrees that posting such information on a company internet site is necessarily duplicative, particularly in those states that have no regulatory program for controlling CCR. In addition, state requirements, whether pursuant to permits or other regulatory mechanisms, may not necessarily correspond to the requirements of this rule.

EPA acknowledges that parties may be suspicious of information self-reported by regulated entities. However, it is important to remember that facilities that provide information in compliance with these regulation remain subject to the penalties for providing false information under 18 U.S.C. 1001, even though the information will not be submitted to EPA. For example, the Tenth Circuit has held that federal jurisdiction lies under 18 U.S.C. 1001 when a defendant has submitted false information to a state delegated to enforce a federal environmental statute. *United States* v. *Wright,* 988 F.2d 1036 (10th Cir. 1993) (defendant submitted false monitoring reports required by the Safe Drinking Water Act to Oklahoma officials). This is consistent with rulings in other areas that the false statement need not be made directly to the federal government. *United States* v. *Uni Oil Co.,* 646 F.2d 946, 954–55 (9th Cir. 1981); *see also United States* v. *Patullo,* 709 F.2d 1178, 1180 (7th Cir. 1983); *United States* v. *Ross,* 77 F.3d 1525, 1544 (7th Cir. 1996) ("This court has repeatedly found the submission of a fraudulent statement to a private (or non-federal government) entity to be within the jurisdiction of a federal agency where the agency has given funding to the entity and fraudulent statements cause the entity to utilize the funds improperly."). As commenters recognized, the potential for criminal penalties under 18 U.S.C. 1001 provides a significant guarantee, as well as a strong incentive for compliance.

EPA also disagrees with the comments raising concern about the homeland security implications of posting information on a CCR surface impoundment's construction, as it relates to structural stability. Much of the information relevant to an impoundment's structural stability is currently available through Google Earth or through EPA's Web site. For example, EPA's Web site currently provides access to all of the information from the responses to EPA's original 104(e) information requires and the information obtained through the CCR Assessment Program. This information can be accessed at the following pages: *http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys/index.htm, http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/index.htm,* and *http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccrs-fs/index.htm.* Moreover, the Department of Homeland Security has cleared both the internet posting of all of the information currently on EPA's Web site, as well as, in general, information on the design, hydraulic parameters, volume of contained liquids and solids, and hazard rating of all major CCR surface impoundments across the U.S.

## VI. Development of the Final Rule—Technical Requirements

### *A. Applicability*

EPA proposed general provisions to identify those solid waste disposal units subject to the proposed RCRA subpart D requirements (*i.e.,* CCR landfills and CCR surface impoundments as defined under proposed § 257.40(b)). The applicability section also identified three of the existing subpart A criteria that would continue to apply to these facilities: § 257.3–1 *Floodplains,* § 257.3–2 *Endangered Species,* and § 257.3–3 *Surface Water.* Consistent with RCRA section 4004(c), EPA specified an effective date of 180 days after publication of the final rule.

The Agency received numerous comments on this part of the rule. In

general, commenters were concerned with three specific areas. First, commenters requested additional clarification as to the specific sources of CCR that would be subject to the requirements of the rule, *i.e.,* CCR generated by the electric utilities and independent power producers. Second, commenters requested clarification on the applicability of the proposed regulations to MSWLFs disposing of CCR and third, the definition and status of "uniquely associated wastes." Uniquely associated wastes are addressed in Unit XIII of this preamble. EPA also received numerous comments regarding the proposal to apply the rule to "inactive" CCR surface impoundments that had not completed closure prior to the effective date of the rule.

EPA is finalizing minimum national criteria that apply to owners and operators of new and existing CCR landfills and CCR surface impoundments, including any lateral expansions of these units that dispose, or otherwise conduct solid waste management of CCR generated from the combustion of coal at electric utilities and independent power producers. The rule applies only to CCR units at "active" electric utilities and independent power producers, *i.e.,* those that generate electricity, regardless of the fuel currently used to produce electricity. However, disposal units at facilities that are "closed"—*i.e.,* the entire facility has been permanently taken out of service and no longer produces electricity—are outside of the scope of this rule.

Unless otherwise provided, the rule applies to CCR units located both on-site and off-site of the electric utility or independent power producer.

1. CCR Generated by Non-Utility Boilers

The requirements of this rule do not apply to wastes, including fly ash, bottom ash, boiler slag, and FGD materials generated at facilities that are not part of the electric power sector or an independent power producer and that use coal as the fuel in non-utility boilers, such as manufacturing facilities, universities, and hospitals. Industries that primarily burn coal to generate power for their own purposes (*i.e.,* non-utilities), also known as combined heat and power (CHP) plants, are primarily engaged in business activities, such as agriculture, mining, manufacturing, transportation, and education. The electricity that they generate is mainly for their own use, but any excess may be sold in the wholesale market. According to the Energy Information Administration (EIA), CHPs produced less than one percent of the total electricity generated from coal combustion in 2013 and, similarly, burned less than one percent of the total coal consumed for electricity generation or less than 5 million tons (*http://www.eia.gov/electricity/data.cfm*).

EPA never proposed to include these wastes in the rule because EPA lacked critical data from these facilities that would allow us to address key Bevill criteria (see 75 FR 35165). These other industries, and the manufacturing industries in particular, generate other types of wastes which are likely to be mixed or co-managed with the CCR at least at some facilities. As a result, the chemical compositions of the co-managed wastes are likely to be fundamentally different from the chemical composition of CCR generated by electric utilities or independent power producers. In addition, EPA noted that insufficient information was available on non-utility boilers burning coal to determine whether a regulatory flexibility analysis would be required under the Regulatory Flexibility Act, and to conduct one if it is necessary. Without such data, we were unable to fully assess CCR wastes from non-utility operations and indicated that we would decide on an appropriate course of action for these wastes after completing this rulemaking (see 75 FR 35129).

Several commenters stated that EPA's decision to propose limiting the scope of the rule only to CCR generated by the electric power sector (electric utilities and independent power producers) was arbitrary. These commenters claimed that CCR generated by the electric power sector and CCR generated by non-utilities are generally comparable in physical and chemical composition and are typically managed similarly. As a result, these commenters suggested that EPA amend the applicability of the rule to subject all facilities that generate CCR to the same disposal requirements. EPA also received comments maintaining that important differences exist between CCR generated by electric power sector facilities and non-utility facilities, and that supported EPA's proposed decision to exclude CCR generated by non-utilities from the rule. Differences identified by the commenters included waste management issues (*e.g.,* mixing and subsequent co-management of non-utility CCR and other industrial wastes generated by non-utilities), CCR generation rates, CCR management unit design, and CCR management unit operation. In response to our request for additional information, a few commenters provided either waste characterization data for non-utility CCR or information on alleged damage cases involving non-utility CCR.

Based on the proposed rule, EPA cannot include these facilities in this final rule, even if the Agency had concluded that it had received the necessary information from commenters. EPA specifically stated its intention to exclude them, and clearly stated that it had not assessed the operations. (See 75 FR 35166.) The Agency provided no indication of any intention to include such facilities, and did not solicit comment on such an option. Moreover, under the Administrative Procedure Act, the public must be given the opportunity to comment on not only the information that would support such an action, but also EPA's evaluation of that information, and the reasoning behind the Agency's decision. And with respect to this subset of facilities, no such opportunity has been presented. EPA will consider the information provided by commenters at a future point, and will determine whether the information is sufficient to address key Bevill criteria and to decide on the appropriate regulatory scheme for disposal of CCR generated by non-utilities. Accordingly, this rule does not apply to owners and operators of landfills and surface impoundments in which CCR are disposed that were generated by non-utility boilers burning coal.

2. CCR Generated Primarily From the Combustion of Fuels Other Than Coal

These requirements also do not apply to fly ash, bottom ash, boiler slag, and flue gas desulfurization materials, generated primarily from the combustion of fuels (including other fossil fuels) other than coal, for the purpose of generating electricity unless the coal comprises more than fifty percent (50%) of the fuel burned on a total heat input or mass input basis, whichever results in the greater mass feed rate of coal (see § 266.112). Fuel mixtures that contain less than 50% coal are not considered to be CCR, but other fossil fuel wastes. Other fossil fuels that are typically co-combusted with coal are oil and natural gas. In the May 22, 2000 Regulatory Determination, EPA determined that it is not appropriate to establish national regulations applicable to oil combustion wastes (OCW) because: (1) We found in most cases that OCW, whether managed alone or co-managed, are rarely characteristically hazardous; (2) we have not identified any beneficial uses that are likely to present significant risks to human health or the environment; (3) we identified no significant ecological risks posed by

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land disposal of OCW; (4) we identified only one documented damage case involving OCW in combination with coal combustion wastes, and it did not affect human receptors; and (5) except for two unlined surface impoundments, we have not identified any significant risks to human health and the environment associated with any waste management practices. Similarly, EPA determined that regulating natural gas combustion wastes is not warranted because the burning of natural gas produces virtually no solid waste. Therefore, the Agency has determined that regulations for wastes generated primarily from the combustion of fuels (including other fossil fuels) other than coal are not warranted unless the fuel mixture consists primarily of coal.

3. Placement of CCR in Minefilling Operations

Consistent with the approach in the proposed rule, this rule does not apply to CCR placed in active or abandoned underground or surface coal mines. The U. S. Department of Interior (DOI) and EPA will address the management of CCR in minefills in a separate regulatory action(s). EPA will work with the OSM to develop effective federal regulations to ensure that the placement of coal combustion residuals in minefill operations is adequately controlled. In doing so, EPA and OSM will consider the recommendations of the National Research Council (NRC), which, at the direction of Congress, studied the health, safety, and environmental risks associated with the placement of CCR in active and abandoned coal mines in all major U.S. coal basins. The NRC published its findings on March 1, 2006, in a report entitled "Managing Coal Combustion Residues (CCR) in Mines," which is available at *http://books.nap.edu/openbook.php?isbn=0309100496.*

The report concluded that the "placement of CCR in mines as part of coal mine reclamation may be an appropriate option for the disposal of this material. In such situations, however, an integrated process of CCR characterization, site characterization, management and engineering design of placement activities, and design and implementation of monitoring is required to reduce the risk of contamination moving from the mine site to the ambient environment." The NRC report recommended that enforceable federal standards be established for the disposal of CCR in minefills to ensure that states have specific authority and that states implement adequate safeguards. The NRC Committee on Mine Placement of Coal Combustion Wastes also stated that OSM and its SMCRA state partners should take the lead in developing new national standards for CCR use in mines because the framework is in place to deal with mine-related issues. Consistent with the recommendations of the National Academy of Sciences, EPA anticipates that the U.S. Department of the Interior (DOI) will take the lead in developing these regulations. EPA will work closely with DOI throughout that process.

4. Municipal Solid Waste Landfills

The issue receiving the majority of comment in this section focused on the applicability of the rule to MSWLFs accepting CCR. The vast majority of commenters on this issue requested that EPA clarify that permitted MSWLFs, receiving CCR as daily cover or for disposal were not covered by the rule.

While most CCR is currently disposed of at electric utility owned CCR landfills or surface impoundments, there is no prohibition against disposing of CCR in state-permitted MSWLFs. However, many commenters interpreted the proposed CCR subtitle D regulations to apply to a state permitted MSWLF disposing of CCR, which as a consequence would be subject to the additional burden of posting documentation to a Web site, having a professional engineer review certification, etc. (See 75 FR 35210, where the preamble states that under a subtitle D regulation, regulated CCR wastes shipped off-site for disposal would have to be sent to facilities that meet the standards above.) Commenters argued that since MSWLFs were never mentioned in the proposed rule, that it should be made clear that the rule did not apply to these facilities. Commenters further contended that since the requirements for CCR landfills were directly modeled from the MSWLF requirements found at 40 CFR part 258, disposal in MSWLFs would be protective of human health and the environment. Commenters also contended that a benefit of MSWLFs would be their ability to provide additional capacity for the disposal of CCR as utilities seek to close, upgrade, or develop their own compliant CCR disposal sites.

EPA recognizes that there are MSWLFs that either accept CCR for disposal, use CCR for as daily cover, or both. Since the proposed and final RCRA subtitle D standards for CCR landfills are modeled after the standards for MSWLFs found at 40 CFR part 258, EPA has concluded that disposal of CCR in MSWLFs is as protective as disposal in a CCR landfill and that permitted MSWLFs are not subject to the requirements of this rule. Like the MSWLF requirements, the CCR technical criteria require new units to have composite liners or their equivalent, and all units are subject to location restrictions, run-on and run-off controls, fugitive dust controls, groundwater monitoring and corrective action, closure and post-closure care requirements.[38]

While the MSWLF fugitive dust criteria (air criteria) are not as specific as those in this rule, § 258.4(a) states that owners or operators of all MSWLFs must ensure that the units not violate any applicable requirements developed under a State Implementation Plan (SIP) approved or promulgated by the Administrator pursuant to section 110 of the Clean Air Act, as amended. It is expected that states will impose additional requirements to address fugitive dusts, of the sort codified in Illinois' 415 ILCS 5/9(a)(2012)[39] and enforced by the state (see *People of the State of Illinois* v. *KCBX Terminals Company,* Injunction no. 2013CH24788 in the Circuit Court of Cook County, Illinois. Moreover, if used as a daily cover, § 258.21 requires that the alternative cover (*i.e.,* CCR) control disease, vectors, odors, blowing litter, and scavenging without presenting a threat to human health and the environment.

The Agency is not requiring MSWLFs that receive CCR for disposal or for use as daily cover to modify their groundwater monitoring programs to comply with the rule; however the Agency expects that State Directors will require MSWLFs to modify their MSWLF permits to address the addition of CCR to the unit as it relates to groundwater monitoring and corrective action. Section 258.54(a)(2) allows for the Director of an approved state to establish an alternative list of inorganic indicator parameters for a MSWLF unit if the alternative parameters provide a reliable indication of inorganic releases

[38] One significant difference however is that MSWLFs are required to have financial assurance, a requirement not applicable to CCR under the subtitle D requirements.

[39] "No person shall (a) Cause or threaten or allow the discharge or emission of any contaminant into the environment in any state so as to cause or tend to cause air pollution in Illinois, either alone or in combination with contaminants from other sources, or so as to violate regulations or standards adopted by the Board under this Act; (b) Construct, install or operate any equipment, facility, vehicle, vessel, or aircraft capable of causing or contributing to air pollution or designed to prevent air pollution, of any typed designated by Board regulations, (1) without a permit granted by the Agency unless otherwise exempt by this Act or Board regulations; or (2) in violation of any conditions imposed by such permit."

from the MSWLF unit to the groundwater (*i.e.,* as would be the case if CCR was disposed in the MSWLF unit). In determining alternative parameters, the Director shall consider, among other things: (1) The types, quantities, and concentrations in wastes managed at the MSWLF unit; (2) the mobility, stability, and persistence of waste constituents or their reaction products in the unsaturated zone beneath the MSWLF unit; and (3) the detectability of indicator parameters, waste constituents, and reaction products in the groundwater. In situations where the MSWLF unit is receiving CCR for disposal and/or daily cover, EPA expects the controlled management of CCR in these units. Specifically, EPA expects State Directors to utilize the provisions in § 258.54(a)(2) to revise the detection monitoring constituents to include those constituents being promulgated in this rule under § 257.90. These detection monitoring constituents or inorganic indicator parameters are: boron, calcium, chloride, fluoride, pH, sulfate and total dissolved solids (TDS). These inorganic indicator parameters are known to be leading indicators of releases of contaminants associated with CCR and the Agency strongly recommends that State Directors add these constituents to the list of indicator parameters to be monitored during detection monitoring of groundwater if and when a MSWLF decides to accept CCR.

The Agency has concluded that CCR can readily be handled in permitted MSWLFs provided that they are evaluated for waste compatibility and placement as required under the part 258 requirements. Furthermore, consistent with the recordkeeping requirements in § 258.29, the Agency further expects State Directors to encourage MSWLF units receiving CCR after the effective date of this rule to do so pursuant to a "CCR acceptance plan" that is maintained in the facility operating record. This plan would assure that the MSWLF facility is aware of the physical and chemical characteristics of the waste received (*i.e.,* CCR) and handles it with the additional precautions necessary to avoid dust, maintain structural integrity, and avoid compromising the gas and leachate collection systems of the landfill so that human health and the environment are protected. While the Agency sees no need to impose duplicative requirements for MSWLFs that receive CCR for disposal or daily cover; development of these acceptance plans as well as a revised list of groundwater detection monitoring constituents will help ensure that CCR is being managed in the most protective manner consistent with the Part 258 requirements.

5. Inactive CCR Surface Impoundments

The final rule also applies to "inactive" CCR surface impoundments at any active electric utilities or independent power producers, regardless of the fuel currently being used to produce electricity; *i.e.,* surface impoundments at any active electric utility or independent power producer that have ceased receiving CCR or otherwise actively managing CCR. While it is true that EPA exempted inactive units from the part 258 requirements in 1990, the original subtitle D regulations at 40 CFR part 257 (which are currently applicable to CCR wastes) applied to "all solid waste disposal facilities and practices" except for eleven specifically enumerated exemptions (none of which are relevant). 40 CFR 257.1(c). See also, 40 CFR 257.1(a)(1)–(2). And as discussed in greater detail below, subtitle D of RCRA does not limit EPA's authority to active units—that is, units that receive or otherwise manage wastes after the effective date of the regulations. EPA has documented several damage cases that have occurred due to inactive CCR surface impoundments, including the release of CCR and wastewater from an inactive CCR surface impoundment into the Dan River which occurred since publication of the CCR proposed rule. As discussed in the proposal, the risks associated with inactive CCR surface impoundments do not differ significantly from the risks associated with active CCR surface impoundments; much of the risk from these units is driven by the hydraulic head imposed by impounded units. These conditions remain present in both active and inactive units, which continue to impound liquid along with CCR. For all these reasons, the Agency has concluded that inactive CCR surface impoundments require regulatory oversight.

The sole exception is for "inactive" CCR surface impoundments that have completed dewatering and capping operations (in accordance with the capping requirements finalized in this rule) within three years of the publication of this rule. EPA considers these units to be analogous to inactive CCR landfills, which are not subject to the final rule. As noted, EPA's risk assessment shows that the highest risks are associated with CCR surface impoundments due to the hydraulic head imposed by impounded water. Dewatered CCR surface impoundments will no longer be subjected to hydraulic head so the risk of releases, including the risk that the unit will leach into the groundwater, would be no greater than those from CCR landfills. Similarly, the requirements of this rule do not apply to inactive CCR landfills—which are CCR landfills that do not accept waste after the effective date of the regulations. The Agency is not aware of any damage cases associated with inactive CCR landfills, and as noted, the risks of release from such units are significantly lower than CCR surface impoundments or active CCR landfills. In the absence of this type of evidence, and consistent with the proposal, the Agency has decided not to cover these units in this final rule.

Under both the subtitle C and subtitle D options, EPA proposed to regulate "inactive" CCR surface impoundments that had not completed closure prior to the effective date of the rule. EPA proposed that if any inactive CCR surface impoundment had not met the interim status closure requirements (*i.e.,* dewatered and capped) by the effective date of the rule, the unit would be subject to all of the requirements applicable to CCR surface impoundments. Under the subtitle C option, those requirements would have included compliance with the interim status and permitting regulations. Under subtitle D, such units would have been required to comply with all of the criteria applicable to CCR surface impoundments that continued to receive wastes, including groundwater monitoring, corrective action, and closure.

EPA acknowledged that this represented a departure from the Agency's long-standing implementation of the regulatory program under subtitle C. While the statutory definition of "disposal" has been broadly interpreted to include passive leaking, historically EPA has construed the definition of "disposal" more narrowly for the purposes of implementing the subtitle C regulatory requirements. For examples see 43 FR 58984 (Dec. 18, 1978); and 45 FR 33074 (May 1980). Although in some situations, post-placement management has been considered to be disposal triggering RCRA subtitle C regulatory requirements, *e.g.,* dredging of impoundments or management of leachate, EPA has generally interpreted the statute to require a permit only if a facility treats, stores, or actively disposes of the waste after the effective date of its designation as a hazardous waste. EPA explained that relying on a broader interpretation was appropriate in this instance given that the

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substantial risks associated with currently operating CCR surface impoundments, *i.e.,* the potential for leachate and other releases to contaminate groundwater and the potential for catastrophic releases from structural failures, were not measurably different than the risks associated with "inactive" CCR surface impoundments that continued to impound liquid, even though the facility had ceased to place additional wastes in the unit. EPA noted as well that the risks are primarily driven by the older existing units, which are generally unlined.

In the section of the preamble discussing the subtitle D option, EPA did not expressly highlight the application of the rule to inactive CCR surface impoundments, but generally explained that EPA's approach to developing the proposed subtitle D requirements for surface impoundments (which are not addressed by the part 258 regulations that served as the model for the proposed landfill requirements) was to seek to be consistent with the technical requirements developed under the subtitle C option. (See 75 FR 35193.) ("In addition, EPA considered that many of the technical requirements that EPA developed to specifically address the risks from the disposal of CCR as part of the subtitle C alternative would be equally justified under a RCRA subtitle D regime . . . The factual record—*i.e.,* the risk analysis and the damage cases—supporting such requirements is the same, irrespective of the statutory authority under which the Agency is operating . . . Thus several of the provisions EPA is proposing under RCRA subtitle D either correspond to the provisions EPA is proposing to establish for RCRA subtitle C requirement. These provisions include the following regulatory provisions specific to CCR that EPA is proposing to establish: *Scope and applicability (i.e., who will be subject to the rule criteria/ requirements*) . . .") (emphasis added).

EPA received numerous comments on this aspect of the proposal. On the whole, the comments were focused on EPA's legal authority under subtitle C to regulate inactive and closed units, as well as inactive and closed facilities. One group of commenters, however, specifically criticized the proposed subtitle D regulation on the grounds that it failed to address the risks from inactive CCR surface impoundments. The majority of commenters, however, argued that RCRA does not authorize EPA to regulate inactive or closed surface impoundments. These commenters focused on two primary arguments: first, that RCRA's definition of "disposal" cannot be interpreted to include "passive migration" based on the plain language of the statute, and second, that such an interpretation conflicted with court decisions in several circuits, holding that under CERCLA "disposal" does not include passive leaking or the migration of contaminants.

In support of their first argument, commenters argued that the plain language of RCRA demonstrates that the requirements are "prospective in nature" and thus cannot be interpreted to apply to past activities, *i.e.,* the past disposals in inactive CCR units. They also argued that the absence of the word "leaching" from the definition of "disposal" clearly indicates that Congress did not intend to cover passive leaking or migration from CCR units. The commenters also selectively quoted portions of past EPA statements, claiming that these demonstrated that EPA had conclusively interpreted RCRA to preclude jurisdiction over inactive units and facilities. In particular, they pointed to EPA's decision in 1980 not to require permits for closed or inactive facilities.

Commenters cited several cases to support their second claim. These include *Carson Harbor Vill.* v. *Unocal Corp.,* 270 F.3d 863 (9th Cir. 2001); *United States* v. *150 Acres of Land,* 204 F.3d 698, 706 (2000); *ABB Industrial Systems* v. *Prime Technology,* 120 F.3d 351, 358 (2d Cir. 1997); *United States* v. *CMDG Realty Co.,* 96 F.3d 706, 711 (3rd Cir. 1996); *Joslyn Mfg. Co.* v. *Koppers Co.,* 40 F.3d 750, 762 (5th Cir. 1994); *Delaney* v. *Town of Carmel,* 55 F. Supp. 2d 237, 256 (S.D.N.Y. 1999); *see also Interfaith Cmty. Org.* v. *Honey-Well Intl Inc.,* 263 F. Supp. 2d 796, 846 n.10 (D.N.J. 2003). The commenters acknowledged that these cases were all decided under CERCLA, but claim that the cases are all equally dispositive with respect to RCRA's definition of disposal because CERCLA specifically incorporates by reference RCRA's statutory definition of disposal.

As an initial matter, it is important to correct certain misunderstandings contained throughout a number of the comments. First, EPA did propose to include inactive units under the subtitle D alternative. EPA clearly signaled its intent to cover the same universe of units and facilities covered under the subtitle C proposal. EPA did not include a corresponding discussion in its explanation of the subtitle D alternative because application of the criteria to inactive units did not represent such a significant departure from EPA's past practice or interpretation. As discussed in more detail below, the original subtitle D regulations applied to all existing disposal units. See 40 CFR 257.1(a)(1)–(2), (c) and 43 FR 4942–4943, 4944.

Second, several commenters criticized EPA's purported proposal to cover both "closed" and "inactive" surface impoundments, using the terms interchangeably. These same commenters also refer to both "inactive facilities" and "inactive units." These are all different concepts, and EPA clearly distinguished between them.

EPA proposed to regulate only "inactive" surface impoundments that had not completed closure of the surface impoundment before the effective date. "Inactive" surface impoundments are those that contain both CCR and water, but no longer receive additional wastes. By contrast, a "closed" surface impoundment would no longer contain water, although it may continue to contain CCR (or other wastes), and would be capped or otherwise maintained. There is little difference between the potential risks of an active and inactive surface impoundment; both can leak into groundwater, and both are subject to structural failures that release the wastes into the environment, including catastrophic failures leading to massive releases that threaten both human health and the environment. This is clearly demonstrated by the recent spill in the Dan River in North Carolina, which occurred as the result of a structural failure at an inactive surface impoundment. Similarly, as demonstrated by the discovery of additional damage cases upon the recent installation of groundwater monitoring systems at existing CCR surface impoundments in Michigan and Illinois, many existing CCR surface impoundments are currently leaking, albeit currently undetected. These are the risks the disposal rule specifically seeks to address, and there is no logical basis for distinguishing between units that present the same risks.

EPA did not propose to require "closed" surface impoundments to "reclose." Nor did EPA intend, as the same commenters claim, that "literally hundreds of previously closed . . . surface impoundments—many of which were properly closed decades ago under state solid waste programs, have changed owners, and now have structures built on top of them—would be considered active CCR units." Accordingly, the final rule does not impose any requirements on any CCR surface impoundments that have in fact "closed" before the rule's effective date—*i.e.,* those that no longer contain water and can no longer impound liquid.

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Further, EPA never proposed that the rule would apply to inactive facilities. The proposal was clear that the regulations would apply to active facilities—*i.e.,* those that continue to generate electricity for distribution to the public, and those that continue to manage CCR. Consistent with that proposal, the final rule applies only to inactive surface impoundments at active electric utilities, *i.e.,* facilities that are actively generating electricity irrespective of the fuel used.

Finally, some comments focused on issues that were specific to the plain language of subtitle C provisions. While most of the issues the commenters raised relate equally to EPA's authority under both subtitles C and D, because the final rule establishes standards under subtitle D of RCRA, EPA has not addressed comments that are purely relevant or applicable to the extent of EPA's authority under subtitle C.

a. Plain Language of RCRA and EPA's Past Interpretations

Under both subtitle C and subtitle D, EPA's authority to regulate "inactive" units primarily stems from the agency's authority to regulate "disposal." The term is defined once in RCRA and applies to both subtitles C and D. Moreover, the definition explicitly includes "leaking" and "placing of any solid waste . . . into or on any land so that such [waste] or any constituent thereof may enter the environment . . . or be discharged into any waters, including groundwaters." 42 U.S.C. 6903(3).

Commenters focused on the past statements that EPA cited in the proposal in acknowledging that the Agency was proposing to revise its interpretation for this rulemaking. In general, the comments misconstrue the significance of these past statements. The cited passages merely explain that the *permitting requirements* in subtitle C were written to be "prospective in nature" and as a consequence, EPA has chosen to interpret "disposal" more narrowly *in that context.* Thus EPA's historic interpretation under subtitle C was not based on an interpretation that the plain language of RCRA's definition of "disposal" precluded reaching inactive units, but on a determination that a narrower interpretation would be reasonable in light of specific language in sections 3004 and 3005, and the practical consequences of applying *these* requirements to inactive facilities.[40]

None of EPA's past statements included any interpretation that "leaking" does not include leaking from an inactive disposal unit, or that the statutory definition of "disposal" cannot be interpreted to apply to the current consequences of past disposals. To the contrary, EPA was clear in the original 1978 proposed hazardous waste regulations that leaking from inactive disposal units constitutes "disposal" under RCRA.

Neither RCRA nor its legislative history discusses whether section 3004 standards for owners and operators of hazardous waste treatment, storage, or disposal facilities apply or were intended to apply to inactive facilities, *i.e.,* those facilities which have ceased receiving, treating, storing, and disposing of wastes prior to the effective date of the subtitle C regulations. "*This is an important issue, however, because some, and perhaps most, inactive facilities may still be "disposing of waste" within the meaning of that term in Section 1004(3) of RCRA.* 'Disposal' includes: the discharge, dumping, spilling, leaking, . . . of any solid waste or hazardous waste into or on any land or water so that such solid waste or hazardous waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including groundwaters. *Many inactive facilities may well be leaking solid or hazardous waste into groundwater and thus be "disposing" under RCRA.*" 43 FR 58984 (emphasis added).

Note as well that EPA declined to impose requirements on "inactive *facilities*" not "inactive *units* at active facilities," which are the entities covered in this final CCR rule. Further, the complications discussed in 1978 were specific to inactive or closed facilities: the concern that the present owner of the land on which an inactive site was located might have no connection (other than present ownership of the land) with the prior disposal activities. Id. These considerations are not relevant to inactive CCR surface impoundments at active electric utilities.

EPA further clarified this position in the 1980 final hazardous waste rule, explaining that, while the Agency did not generally intend to regulate those portions of facilities that had closed before the effective date, there were exceptions to this, and that in individual cases, inactive portions of a facility—or in other words, inactive units, might be regulated.

> [O]wners and operators which continue to operate after the effective date of the regulations must ensure that portions of facilities closed before the effective date of these rules do not interfere with the monitoring or control of active portions. This requirement regulates the facility which operates under the RCRA regulations, although it may require the owner or operator before he receives a permit, or, as a permit condition, to take certain measures on portions of his facility closed before the effective date of these regulations.

45 FR 33068. (See also 45 FR 33170.)

In other words, EPA was clear that its jurisdiction under RCRA extended to these portions of the facility but that the Agency had made a policy choice not to exert its regulatory jurisdiction as a general matter over inactive facilities, choosing instead to rely on section 7003 and CERCLA to address the risks and require clean-up of these sites. EPA has adopted a substantially similar approach here, requiring the current owner or operator of an active facility to address the risks associated with an inactive portion of the facility that could potentially interfere with the monitoring or control of the actively operating portion of the facility through leaking contaminants or other releases.

Similarly, in the 1980 final rules, EPA expressly declined to revise the regulatory definition of disposal to exclude accidental or unintentional releases. EPA noted that "[r]egardless of whether a discharge of hazardous waste is intentional or not, the human health and environmental effects are the same. Thus intentional and unintentional discharges are included in the definition of 'disposal.' " (See 45 FR 33068.) While EPA revised other provisions to clarify that a permit would not be required for accidental discharges, EPA was clear that such activities are properly considered to be "disposal."

By contrast, EPA's past implementation of subtitle D, following from the legislative history and the statutory language, consistently applied regulatory requirements equally to all facilities, without distinguishing between active and inactive or new and existing facilities.

Congress was clear that subtitle D was intended to specifically address the problem of abandoned leaking "open dumps" scattered across the country, "where frequently the use of the site for waste disposal is neither authorized nor supervised." H. Rep. No. 94–1491, p 37, 94th Cong., 2d Sess (1976). For example, the report described the consequences when "the City of Texarcana Arkansas/Texas, abandoned its six open dumps, in 1968" to support the need to require open dumps to upgrade or close.

[40] It is also clear that certain subtitle C requirements in fact do apply to inactive units, for example, section 3004(u) requires facilities to clean up releases from inactive units located on the facility site.

Similarly, in describing the need for the legislation, the House report stated:

> Disposal of solid wastes, including hazardous wastes, can have adverse environmental impacts in several ways. The following paragraphs discuss five different types of such impacts.
>
> (i) Perhaps the most pernicious effect is the contamination of groundwater by leachate from land disposal of waste. About half of the U.S. domestic water supply is from underground water, and thus is potentially subject to contamination. Such contamination is particularly vexing because often it is discovered after the damage is done and because the contamination is very long lasting. Thus leachate from a landfill or dump may not show up for years, *maybe not even until after the landfill is closed.*

Id. at 89 (emphasis added).

Consequently, subtitle D of RCRA provides clear authority to address inactive or abandoned disposal sites. The relevant provisions of RCRA subtitle D do not distinguish between "active" and "inactive" disposal units. Nor do any of the relevant provisions tie jurisdiction to the receipt or disposal of waste after a specific date.

RCRA section 1004(14) defines an "open dump" as "*any* facility or site where solid waste is disposed of which is not a sanitary landfill which meets the criteria promulgated under section [4004] of this chapter and which is not a facility for disposal of hazardous waste." 42 U.S.C. 6903(14) (emphasis added). Section 4004(a) delegates broad authority to EPA to determine the facilities that will be considered "open dumps," without any requirement that the units or facilities be in operation. "[T]he Administrator shall promulgate regulations containing criteria for determining which facilities shall be classified as sanitary landfills and which shall be classified open dumps within the meaning of this chapter." 42 U.S.C. 6944(a). Section 4005(a), which is titled, "Closing or upgrading of existing open dumps," is also not limited in scope: "Upon promulgation of criteria under [1008(a)(3)] of this title, *any* solid waste management practice of disposal of solid waste or hazardous waste which constitutes the open dumping of solid or hazardous waste is prohibited, . . ." 42 U.S.C. 6945(a) (emphasis added). See also, section 4003(a)(3), requiring state plans to provide for the closing or upgrading of "*all existing* open dumps"). 42 U.S.C. 6943(a)(3) (emphasis added).

Consistent with the statutory provisions, EPA's current subtitle D regulations at 40 CFR part 257 apply to "all solid waste disposal facilities and practices" whether active or inactive, and did not differentiate between new and existing facilities.[41] 40 CFR 257.1(c). See also, 40 CFR 257.1(a)(1)–(2). EPA was clear in both the proposed and final rules that the rules applied to all existing facilities: "These criteria for the classification of disposal facilities apply to all "solid waste" and "disposal" facilities, which are defined in the Act [in] (section 1004)." 43 FR 4942–4943, 4944. The final rule was equally clear: "These criteria apply to the full range of facilities and practices for "disposal" of "solid waste," as those terms are defined in the Act." 44 FR 53440. (See also 44 FR 53438.) The final rule describes eight categories of materials or activities that are excluded; inactive facilities or units are not among them. This stands in stark contrast to the hazardous waste regulations, which, as discussed, specifically exempted inactive facilities from the permitting and associated regulatory requirements.

b. Case Law on the Definition of Disposal

EPA also disagrees with the commenters' second claim that regulating inactive surface impoundments would be inconsistent with case law in six circuits. The commenters are correct that some courts have held that the subsequent passive migration of contamination left on-site is insufficient to support liability against a *third party* that merely owned the property *under CERCLA*. But the commenters misconstrue this case law and fundamentally overstate its significance to the issue at hand. Of greater significance, however, is that federal courts have almost universally reached different conclusions under RCRA, holding that the statutory definition of disposal does include the passive migration of contamination from previously disposed of wastes.

As an initial matter, the issue decided by the courts in the cited CERCLA cases was narrower than the commenters allege; these cases generally focused on whether current or past owners of land contaminated by the activities of *other owners* were liable for passive migration that occurred during their ownership of the land. This is very different than the situation at hand, in which regulatory requirements are being imposed to address the existing and future contamination caused by the past and current activities of the current owner.

In addition, these decisions were largely predicated on language that is unique to CERCLA, rather than on a definitive reading of RCRA's definition of disposal. *See, e.g., United States* v. *CMDG Realty Co.,* supra at 712–717. For example, in *CMDG Realty,* the court found that passive migration was not disposal because Congress had clearly distinguished between "releases," and "disposal," defining the two terms differently and imposing liability on different parties for the two activities. Id. *Accord, Carson Harbor Village, supra,* at 880–885; *ABB Industrial Systems* v. *Prime Technology,* supra at 358.

Moreover, even under CERCLA courts have not universally reached the same conclusions on whether "passive migration" can be considered "disposal." *See, e.g., Nurad, Inc.* v. *William E. Hooper & Sons Co.,* 966 F.2d 837, 844–46 (4th Cir. 1992) (concluding that because the definition of disposal includes "leaking," prior owners are liable if they acquired a site with leaking barrels or underground storage tanks even though the prior owner's actions are purely passive); *ABB Industrial Systems,* Id., n.3 (expressly declining to decide whether passive migration could ever be considered "disposal").

But in any event, courts have consistently interpreted RCRA to apply to passive migration. Two cases under RCRA are the most directly analogous to the current situation as they address the extent of EPA's authority to regulate based on the statutory definition of "disposal": *In re Consolidated Land Disposal Regulation Litigation,* 938 F.2d 1386 (D.C. Cir. 1991), and *United States* v. *Power Engineering Co.,* 10 F. Supp. 2d 1145 (D. Colo. 1998), *aff'd* 191 F.3d 1224 (10th Cir. 1999). In both cases, the court considered whether EPA could impose or enforce regulatory requirements to address passive migration under the interpretation that this constituted "disposal" under RCRA. And in both cases the court agreed that RCRA's definition encompassed such activities.

The issue in *Consolidated Land Disposal* was whether EPA could require closed hazardous waste facilities to obtain a "post-closure" permit. 938 F.2d at 1388–1389. EPA had relied on the definition of disposal to support the regulation, concluding that a facility "at which hazardous wastes have been disposed by placement in or on the land" remains subject to both permitting and regulation because "such hazardous wastes or constituents may continue 'leaking' or 'may enter the environment or be emitted . . . or discharged . . .'" into the environment." Id. Similar to the commenters' current arguments, the petitioners argued that under § 3005, a permit can only be required for "on-

[41] The regulations establish eleven specifically enumerated exemptions, none of which are relevant to the units at issue.

going activities"—the treatment, storage, or disposal of waste at such facilities—not for the facility itself post-closure. The petitioners argued that linguistically, "disposal . . . is not a continuing activity but occurs anew each time waste is placed into or on land." The D.C. Circuit summarily rejected the petitioners' interpretation, holding that this "may be one way in which the word is used in ordinary language, but is not necessarily how it is used in the statute; the equation of "disposal" with "leaking," which is a continuous phenomenon rather than a discrete event, is enough to blunt the sting of the petitioners' point." Id. This case is essentially dispositive of the issue, given the similarities between the requirement for a post-closure permit and the final requirements applicable to inactive CCR surface impoundments. Electric utilities retain ownership and control over these existing CCR units, just as hazardous waste facilities retain ownership and control over the closed units subject to post-closure permitting. In both situations, EPA requirements are designed to address both the existing and future risks of further "releases" or "leaking" from these units—*i.e.,* further disposal, as that term is defined in section 1004.

Similarly, in *Power Engineering* the court considered whether under section 3008 of RCRA, EPA could bring an action to compel the operator of a metal refinishing plant to comply with the state's RCRA regulations relating to financial assurance.[42] 10 F. Supp.2d at 1159. The defendants argued that since they were not currently disposing of waste, they were operating in compliance with state regulations and were exempt from financial assurance requirements. The court disagreed. It held that the use of the word "leaking" in the definition of "disposal" indicated that the leaching of hazardous waste into the groundwater constitutes the continuing disposal of hazardous waste. Id. at 1159–60 ("Because the definition of "disposal" includes the word "leaking," disposal occurs not only when a solid waste or a hazardous waste is first deposited onto ground or into water, but also when such wastes migrate from their initial disposal location.").

Courts in several circuits have also considered whether the passive migration of previously dumped waste constitutes a current or ongoing violation of RCRA, *i.e.,* illegal "disposal," under the citizen suit provisions of section 7002(a)(1)(A). Most have concluded that it does. *See, Scarlett & Associates* v. *Briarcliff Center Partners,* 2009 WL 3151089 (N.D. Ga 2009) (deciding to "follow the majority rule" and holding that "the continued presence of migrating waste constitutes a continuing violation under the RCRA"); *Marrero Hernandez* v. *Esso Standard Oil Co.,* 597 F. Supp. 2d 272, 283 (D.P.R. 2009) (holding that unremedied, migrating contamination is not a wholly past violation); *Cameron* v. *Peach County, GA,* No. 5:02–CV–41–1 (CAR), 2004 WL 5520003 (M.D. Ga. 2004) (holding that the continued presence of illegal contamination that remains remedial constitutes a continuing violation, even though the acts of unlawful disposal occurred in the past); *California* v. *M&P Investments,* 308 F. Supp. 2d 1137, 1146–1147 (E.D. CA 2003) (Allowing RCRA 7002 claim of continuing violation to proceed on evidence that wastes "continue to exist unremediated" as a result of improper discharge that had ceased over 20 years prior to filing of suit); *Aurora National Bank* v. *TriStar Marketing,* 990 F. Supp. 1020, 1025 (N.D. Ill. 1998) ("Although subsection (a)(1)(A) does not permit a citizen suit for wholly past violations of the statute, the continued presence of illegally dumped materials generally constitutes a 'continuing violation' of the RCRA, which is cognizable under § 6972(a)(1)(A)."') (internal citation omitted); *City of Toledo* v. *Beazer Materials & Servs., Inc.,* 833 F. Supp. 646, 656 (N.D. Ohio 1993) ("[T]he disposal of wastes can constitute a continuing violation so long as no proper disposal procedures are put into effect or as long as the waste has not been cleaned up and the environmental effects remain remediable."); *Gache* v. *Town of Harrison,* 813 F. Supp. 1037, 1041–42 (S.D.N.Y. 1993) ("The environmental harms do not stem from the act of dumping when waste materials slide off the dump truck but rather after they land and begin to seep into the ground, contaminating soil and water. So long as wastes remain in the landfill threatening to leach into the surrounding soil and water, a continuing violation sure may exist."); *Acme Printing Ink Co.* v. *Menard, Inc.,* 812 F. Supp. 1498, 1512 (E.D. Wisc. 1992) ("RCRA includes in its broad definition of 'disposal' the continuous leaking of hazardous substances. . . . Accordingly, leaking of hazardous substances may constitute a continuous or intermittent violation of RCRA."); *Fallowfield Dev. Corp.* v. *Strunk,* No. 89–8644, 1990 WL 52745 (E.D. Pa. 1990) ("If a person disposes of hazardous waste on a parcel of property, the hazardous waste remains in that property insidiously infecting the soil and groundwater aquifers. In other words, the violation continues until the proper disposal procedures are put into effect or the hazardous waste is cleaned up."). It is particularly notable that these cases were all decided under subsection (A); in contrast to subsection (B), section 7002(a)(1)(A) does not include any reference to liability for past actions or for prior owners. *Compare,* 42 U.S.C. 6972(a)(1)(A) and (B). In reaching their holdings, therefore, the courts necessarily relied [solely] on the reach of the statutory definition of "disposal," which is at the heart of EPA's authority to regulate inactive CCR surface impoundments.

Courts have also addressed the limits of RCRA's definition of "disposal" is in the context of an EPA action under RCRA section 7003. Section 7003 authorizes EPA to obtain injunctive relief for actions, including disposal that "may present an imminent and substantial endangerment to health or the environment." 42 U.S.C. 6973(a). Several courts have evaluated whether an inactive disposal site, where no affirmative acts of disposal are occurring, constitute an "imminent and substantial endangerment" under this provision. Once again, most courts accept a definition of disposal that encompasses leaking or contaminant migration from previously discarded wastes. *See United States* v. *Price,* 523 F. Supp. 1055, 1071 (D.N.J. 1981), *aff'd United States* v. *Price,* 688 F.2d 204 (3rd Cir. 1982) ("There is no doubt, however, that [section 70003] authorizes the cleanup of a site, even a dormant one, if that action is necessary to abate a present threat to the public health or the environment.") *citing* S. Rep. No. 96–848, 96th Cong., 2d Sess., at 11 (1980); H. R. Rep. 96–1016 (Part I), 96th Cong., 2nd Sess., at 21 reprinted in [1980] U.S. Code Cong. & Ad. News, 6119, 6124; *United States* v. *Waste Indus.,* 734 F.2d 159 (4th Cir. 1984) (Rejecting district court interpretation that disposal only includes "active human conduct" based on the inclusion of "leaking" in the definition of disposal, and interpreting the "movement of the waste after it has been placed in a state of repose [to be] encompassed in the broad definition of disposal"); *United States* v. *Diamond Shamrock Corp.,* 12 Envtl. L. Rep. 20819, 20821 (N.D. Ohio May 29, 1981) (noting that "a disposal clearly requires no active human conduct"); *United States* v. *Conservation Chemical Co.,*

[42] Under RCRA's financial assurance regulations, owners and operators of hazardous waste facilities must document that they have sufficient resources to close their facilities and pay third-party claims that may arise.

619 F. Supp. 162, 200 (D. Mo. 1985) (" 'disposal' occurs. . .when [wastes] migrate from their initial location"). See also S. Rep. 98–284, p 58 (98th Cong. 1st Sess.) ("The Environmental Protection Agency and the Department of Justice have used the equitable authority and [sic] granted in section 7003 to seek court orders directing those persons whose past or present acts have contributed to or are contributing to the existence of an imminent and substantial endangerment to abate such conditions. This has been an intended use of the section 7003 since 1976. . . . An [sic] evidenced by the definition of 'disposal' in section 1004(3), which includes the leaking of hazardous wastes, section 7003 has always provided the authority to require the abatement of present conditions of endangerment resulting from past disposal practices, whether intentional or unintentional.").

While EPA continues to maintain that the statutory definition of disposal does in fact authorize regulation of inactive CCR surface impoundments, this is not the sole basis for that authority. Under section 1008(a)(3), EPA is authorized to establish criteria governing solid waste management, which includes the "storage" of solid waste. 42 U.S.C. 6904(28) and 6908(a)(3). RCRA's definition of "storage" is limited to hazardous waste; under subtitle D, therefore, the definition Congress intended was the dictionary definition, which incontrovertibly covers the activities associated with continuing to maintain CCR in inactive surface impoundments. For example, Merriam Webster defines "storage" as "the state of being kept in a place when not being used" and "the act of putting something that is not being used in a place where it is available, where it can be kept safely, etc."

Finally, consistent with the proposed rule and the final Regulatory Determination in Unit IV.B of this document, the final rule does not apply to CCR that is beneficially used.

6. Beneficial Use

The proposed rule generally distinguished between the disposal of CCR and the beneficial use of CCR. Disposal activities would be subject to regulation under one of two alternative regulatory schemes. But under either alternative, beneficial use would remain Bevill exempt and would not be subject to regulation. The proposal identified specific criteria that would be used to distinguish between legitimate beneficial uses of CCR and the disposal of CCR. These criteria were largely drawn from the approach contained in the May 2000 Bevill Regulatory Determination. The criteria were:

—The material used must provide a functional benefit. For example, CCR in concrete increases the durability of concrete—and is more effective in combating degradation from salt water; synthetic gypsum serves exactly the same function in wallboard as mined gypsum, and meets all commercial specifications; CCR as a soil amendment adjusts the pH of soil to promote plant growth.

—The material substitutes for the use of a virgin material, conserving natural resources that would otherwise need to be obtained through practices, such as extraction. For example, the use of FGD gypsum in the manufacture of wallboard (drywall) decreases the need to mine natural gypsum, thereby conserving the natural resource and conserving energy that otherwise would be needed to mine natural gypsum; the use of fly ash in lieu of Portland cement reduces the need for cement. CCR used in road bed replace quarried aggregate or other industrial materials.

—Where relevant product specifications or regulatory standards are available, the materials meet those specifications, and where such specifications or standards have not been established, they are not being used in excess quantities. For example, when CCR is used as a commercial product, the amount of CCR used is controlled by product specifications, or the demands of the user. Fly ash used as a stabilized base course in highway construction is part of many engineering considerations, such as the ASTM C 593 test for compaction, the ASTM D 560 freezing and thawing test, and a seven day compressive strength above 2760 kPa (400 psi). If excessive volumes of CCR are used—*i.e.*, greater than were necessary for a specific project,—that could be grounds for a determination that the use is not beneficial, but rather is being disposed of. 75 FR 35162–35163.

EPA explained that in the case of agricultural uses, CCR would be expected to meet appropriate standards, constituent levels, prescribed total loads, application rates, etc. EPA has developed specific standards governing agricultural application of biosolids. While the management scenarios differ between biosludge application and the use of CCR as soil amendments, EPA stated that the Agency would consider application of CCR for agriculture uses not to be a legitimate beneficial use if they occurred at constituent levels or loading rates greater than EPA's biosolids regulations allow. (75 FR 35162–35163, June 21, 2010)

EPA proposed to codify these criteria in the term, "beneficial use of coal combustion products (CCPs)." This definition stated that the beneficial use of CCPs was the use of CCPs that provides a functional benefit; replaces the use of an alternative material, conserving natural resources that would otherwise need to be obtained through practices such as extraction; and meets relevant product specifications and regulatory standards (where these are available). CCPs that are used in excess quantities (*e.g.*, the field-applications of FGD gypsum in amounts that exceed scientifically-supported quantities required for enhancing soil properties and/or crop yields), placed as fill in sand and gravel pits, or used in large scale fill projects, such as restructuring the landscape, are excluded from this definition. (75 FR 35129–35130, June 21, 2010).

Commenters generally supported the criteria in the proposal but raised concern that the criteria lacked specificity; some commenters stated that the criteria were those that states already considered in doing their beneficial use determination. Commenters also suggested the use of a "no toxics" provision and others suggested that the criteria include a requirement that "environmental benefits" be achieved. A more general comment raised by several commenters was that the proposed criteria failed to establish any standard that ensured protection of human health and the environment. Finally, one commenter raised concern that EPA's approach to beneficial use, and particularly to large scale fill operations, inappropriately assumed that these operations constituted the disposal of solid waste, which, the commenter claimed was inconsistent with a series of judicial decisions.

There are generally three critical issues in determining whether a material is regulated under RCRA subtitle D: whether the material is a "solid waste," whether the activity constitutes "disposal," and whether regulation of the disposal is warranted. Although there can be some overlap between these issues in that the same facts may be relevant to each of them, understanding the distinction between them is critical to understanding the final approach to the beneficial use of CCR adopted in this rulemaking.

In order to be subject to RCRA, the material must be a solid waste. The statute defines a solid waste as "any garbage, refuse . . . and other discarded material. . . ." 42 U.S.C. 6903(27). As EPA noted in the proposed rule, for some beneficial uses, CCR is a raw

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material used as an ingredient in a manufacturing process that have never been "discarded," and thus, would not be considered solid wastes under the existing RCRA regulations. For example, synthetic gypsum is a product of the FGD process at coal-fired power plants. In this case, the utility designs and operates its air pollution control devices to produce an optimal product, including the oxidation of the FGD to produce synthetic gypsum. In this example, after its production, the utility treats FGD as a valuable input into a production process, *i.e.,* as a product, rather than as something that is intended to be discarded. Wallboard plants are sited in close proximity to power plants for access to raw material, with a considerable investment involved. Thus, FGD gypsum used for wallboard manufacture is a product rather than a waste or discarded material. This use and similar uses of CCR that meet product specifications would not be regulated under the final rule.

However, this does not describe the majority of CCR, which are unambiguously wastes; after generation in the boiler, they are placed into landfills or surface impoundments. While they may subsequently be dredged from these units and reused, placement in a landfill or surface impoundment presents prima facie evidence of discard. At the time the material is placed into the unit, the utility is not treating the material as a valuable product or otherwise seeking to protect the material for use. Although the material may subsequently be reused if a buyer is found, the material is originally placed in the unit with the intent to let it remain in place if no buyer is found. The waste designation does not change merely because a material in a surface impoundment or landfill may in the future be beneficially reused.

For those materials that are "wastes" the second issue becomes relevant: whether the activities involved with the material constitutes "disposal" or "solid waste management." The statute distinguishes between these activities and "use;" several activities are listed in the definitions of "disposal" and "solid waste management" and "use" is not among them. See 42 U.S.C. 6903(3) and (28). In general, commenters agreed that the three criteria in the proposal, and discussed above, would identify those activities that were properly considered to be legitimate beneficial uses rather than disposal. As several commenters noted, many state beneficial use programs rely on similar (or identical) criteria. And for encapsulated uses, EPA agrees that these three criteria are sufficient to distinguish between the activities that will be regulated as disposal under this final rule and those that will be considered beneficial use. Accordingly, EPA has adopted them in the final definition of "beneficial use."

But as EPA acknowledged in the proposal, the issues are more difficult with regard to unencapsulated uses. Because these uses involve the direct placement of CCR on the land, they are clearly more analogous to activities that have consistently been considered to be "disposal." RCRA defines disposal to specifically include the "placing of any solid waste or hazardous waste into or on any land or water so that such solid waste or hazardous waste or any constituent thereof may enter the environment . . ." 42 U.S.C. 6903(3). The issue is further complicated by the fact that there can be risks associated with placement of unencapsulated CCR on the land. As described in the proposal, CCR can leach toxic metals at levels of concern. The major risks associated with the placement of unencapsulated CCR on the land for beneficial use involved using large volumes of CCR to restructure the landscape, such as occurred at the Battlefield golf course, and placement in quarries and sand and gravel pits, such as occurred at the Gambrills, Maryland site. EPA acknowledged in the proposal that these types of operations would be subject to regulation as disposal, and so were not directly on point. However, because these damage cases involved the placement of unencapsulated CCR on the land, they raised questions regarding the safety of other uses of unencapsulated CCR that involved direct placement on the land. In addition, previous risk analyses do not address many of the use applications currently being implemented, and have not addressed the improved leachate characterization methods. EPA also noted that some scientific literature indicates that the uncontrolled (*i.e.,* excessive) application of CCR can lead to the potentially toxic accumulation of metals.[43]

As noted, several commenters raised concern that EPA's beneficial use criteria did not include any standard that ensured protection of human health and the environment. EPA agrees that a criterion that accounted for the potential risks of the land placement of unencapsulated CCR would be an appropriate element to include in differentiating between disposal and beneficial use. RCRA's definition of disposal includes some elements related to risk: specifically, the definition includes as a relevant concept that the waste or any constituent of concern "may enter the environment." In this regard it is also relevant that not all disposal activities are regulated by EPA under subtitle D; rather, EPA only regulates those that present risks that exceed the Agency's acceptable risk levels.

Building off of these concepts, the Agency has developed an additional criterion to address both the question of whether the activity is appropriately considered to be "disposal," and the question of whether that "disposal" warrants regulation. Because uses that fail to meet the beneficial use criteria will be considered disposal and would therefore be considered disposal subject to the final regulation, this fourth criterion was designed to exclude uses likely to present the same risks as the management practices regulated under other sections of the final rule. Thus, the final criterion directly correlates to the practices and the risks that the disposal regulations are designed to address: the risks associated with the placement of large quantities of CCR in a single concentrated location, such as a CCR landfill, as documented in the 2014 risk assessment and the damage cases.

As discussed in more detail below, to be considered a "beneficial use," prior to initiating an activity that involves placing unencapsulated CCR on the land in amounts greater than 12,400 tons, in non-roadway applications, the user must demonstrate that environmental releases to groundwater, surface water, soil and air are comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use.

EPA acknowledges that there may be risks associated with uses that are below this threshold, depending on the characteristics of the CCR, the amount of material and the manner in which it is placed, and (perhaps most important) the site conditions. Consequently, all unencapsulated uses, including use in road construction and agriculture, should be conducted with care, according to appropriate management

[43] See, for example, "Effects of coal fly ash amended soils on trace element uptake in plant," S.S. Brake, R.R. Jensen, and J.M. Mattox, Environmental Geology, November 7, 2003 available at *http://www.springerlink.com/content/3c5gaq2qrkr5unvp/fulltext.pdf*; See information regarding the Town of Pines Groundwater Plume at *http://www.epa.gov/region5superfund/npl/sas_sites/INN000508071.htm*. Also see additional information for this site at *http://www.epa.gov/region5/sites/pines/#updates*.

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practices, and with appropriate characterization of the material and the site where the material will be placed. However, as discussed in the previous section, because the amounts and, in some cases, the manner in which the CCR are used are very different from the land disposal modeled in the risk assessment, EPA cannot extrapolate from the risk assessment to reach conclusions regarding the risks these uses may pose. And in the absence of such information, EPA cannot establish criteria to regulate these uses.

a. Final Definition of the Term "Beneficial Use of CCR"

The final beneficial use criteria are as follows: (1) The CCR must provide a functional benefit; (2) The CCR must substitute for the use of a virgin material, conserving natural resources that would otherwise need to be obtained through practices such as extraction; (3) the use of CCR must meet relevant product specifications, regulatory standards, or design standards when available, and when such standards are not available, CCR are not used in excess quantities; and (4) when unencapsulated use of CCR involves placement on the land of 12,400 tons or more in non-roadway applications, the user must demonstrate and keep records, and provide such documentation upon request, that environmental releases to groundwater, surface water, soil and air are comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use. Any use that fails to comply with all of the relevant criteria will be considered to be disposal of CCR, subject to all of the requirements in the disposal regulations, and the user will be considered to be the owner or operator of a CCR disposal unit. Encapsulated uses need only comply with the first three criteria. Unencapsulated uses involving placement on the land of 12,400 tons or more in non-roadway applications that fail to meet all of the beneficial use criteria are considered a CCR unit. As previously noted, the first three criteria were discussed in the proposal and commenters generally supported these criteria, which establish flexible performance standards. As discussed above, the Agency has developed an additional criterion in response to comments, which generally reflects the issues discussed in the proposal. This additional criterion is designed to address the environmental and human health concerns associated with large-scale, unencapsulated uses that have features similar to landfills. These four criteria are discussed in greater detail in the sections below. Any user of CCR that, at a later time, believes that there could be a health or environmental issue associated with their beneficial use should work with their state agency to address any potential issue.

As noted above, encapsulated uses of CCR must only comply with the first three criteria. Encapsulated beneficial uses are those that bind the CCR into a solid matrix that minimizes their mobilization into the surrounding environment. Examples of encapsulated uses include, but are not limited to: (1) Filler or lightweight aggregate in concrete; (2) a replacement for, or raw material used in production of, cementitious components in concrete or bricks; (3) filler in plastics, rubber, and similar products; and (4) raw material in wallboard production.

Compliance with the first three criteria suffices because, as discussed in Unit IV of this document, the available information demonstrates that encapsulated uses of CCR raise minimal health or environmental concerns. The Agency did not receive any data to contradict this assessment during any of the comment periods. In addition, since publication of the proposal, the Agency conducted a study of FGD gypsum in wallboard and fly ash concrete, which further supports this conclusion. This study "*Coal Combustion Residual Beneficial Use Evaluation: Fly Ash Concrete and FGD Gypsum Wallboard*" (February 2014) concluded that "environmental releases of constituents of potential concern (COPCs) from CCR fly ash concrete and FGD gypsum wallboard during use by the consumer are comparable to or lower than those from analogous non-CCR products, or are at or below relevant regulatory and health-based benchmarks for human and ecological receptors."

*Criteria 1: CCR must provide a functional benefit.* This criterion is designed to ensure that the material performs a genuine function in the product or use; while it need not improve product performance when compared to the material for which it is substituting, CCR must genuinely be a necessary component of the product. In other words, there must be a legitimate reason for using CCR in the product other than the fact that it is an alternative to disposal of the material, *e.g.,* the material fulfils material specifications. For example, CCR provides a functional benefit when used as a replacement for cement in concrete because the CCR increases the durability of the concrete and is also more effective against degradation from salt water. FGD gypsum serves the same function in the production of wallboard as mined gypsum, and meets all product specification. Additionally, CCR can be used to adjust the pH of soils thereby increasing and promoting plant growth.

One commenter noted that many states already consider whether the material provides a functional benefit when making beneficial use determinations under their regulatory programs. The Agency agrees that this is an important criterion in determining whether a use is a "beneficial use." To the extent that a state regulatory program has determined that a particular use provides a functional benefit, this may serve as evidence that this criterion has been met.

*Criteria 2: CCR must substitute for the use of a virgin material, conserving natural resources that would otherwise need to be obtained through practices, such as extraction.* This criterion is intended to ensure that the use is truly "beneficial" from an environmental perspective. Examples of CCR used as a substitute for a virgin material include FGD gypsum for mined gypsum and the use of fly ash in lieu of Portland cement thereby reducing the need for cement. The use of FGD gypsum in the manufacture of wallboard reduces the need to use virgin gypsum, thereby conserving natural resources (virgin gypsum) while conserving valuable energy that would be needed to mine the virgin gypsum. Similarly, the use of CCR fly ash in lieu of Portland cement reduces the overall need for cement. CCR used in a road bed application substitutes for the use of quarried natural materials that provide structural support for the road surface.

One commenter again highlighted that many states consider this criterion in their current state beneficial use programs. The Agency agrees that this second criterion is appropriate, and that conserving natural resources is an important function that should be encouraged. Here as well, potential users of CCR materials may choose to rely on a state determination to provide evidence that this criterion has been met.

*Criteria 3: The use of CCR must meet relevant product specifications, regulatory standards, or design standards, when available, and where such specifications or standards have not been established, CCR may not be used in excess quantities.* This criterion was intended to address both the legitimacy of the use and the potential environmental and human health

consequences associated with the use of excess quantities of CCR, particularly unencapsulated CCR. If excessive volumes of CCR are used—*i.e.,* greater than necessary for a specific project—that calls into question whether the purpose of the application was in fact a sham to avoid compliance with the disposal regulations. In addition, the record demonstrates that the risks from use of CCR are more likely to be associated with large volumes, particularly for unencapsulated uses.

The Agency has modified this criterion slightly from the proposed rule. The proposed rule merely referenced "relevant product specifications or regulatory standards" and EPA was concerned that this was too narrow, and might not incorporate all of the relevant technical information currently available that provides guidance on what constitutes an excess amount. Consequently, in the final definition the Agency has added the phrase "design standards." Design standards are different from product specifications, because they include things other than "products." An example of a "design standard" would be technical guidance specifying that six inches of CCR is to be used in constructing a road.

EPA received several comments on this provision, several of which criticized the sole reliance on engineering performance standards. For example, one commenter questioned how the Agency would quantify acceptable amounts for each use if no specifications or standards were in place. One commenter stated that the Agency needs to rely on more than the existence of engineering performance standards or comparisons to typical application rates of mined materials as coal combustion wastes are unique materials and comparisons to typical rates of application of natural gypsum or other soil amendments are inappropriate. Another commenter suggested a provision that would require users to follow a plan to only use what is necessary to reach the desired effect, in lieu of product specifications.

EPA purposely did not attempt to establish product specifications for each potential beneficial use application. The potential products are too varied, and in many instances EPA lacks the necessary expertise (*e.g.,* to develop manufacturing specifications for individual products.). Nor is such an approach necessary. When CCR substitutes for other materials, the amount used is typically controlled by product specifications, particularly for encapsulated uses. Product specifications currently exist for many, if not most, of the significant uses of CCR and can be found in a variety of sources. For example, as previously described, fly ash used as a stabilized base course in highway construction is subject to both regulatory standards under DOT/FHWA, and engineering specifications, such as the ASTM C 593 test for compaction, the ASTM D 560 freezing and thawing test, and a seven-day compressive strength above 2760 kPa (400 psi).

Similarly, in an agricultural setting, EPA expects all appropriate standards, constituent levels, prescribed total loads, and application rates to be met. For example, EPA has developed specific standards governing the agricultural application of biosolids. While the management scenarios differ between biosludge application and the use of CCR as soil amendments, EPA would consider application of CCR for agriculture uses not to be a legitimate beneficial use if they occurred at constituent levels or loading rates greater than EPA's biosolids regulations. Several commenters also noted that agronomic rates currently exist for certain items such as peanuts, cotton, tomatoes, corn and soybeans.[44] EPA would generally consider application of CCR above these rates, or any other rate that has been scientifically justified, to constitute disposal rather than beneficial use.

Many other sources of technical reports and documents exist for other uses. ASTM Standard E2277–03 provides standard guidance and a methodology for using CCR in a structural fill and includes a consideration of engineering properties and behaviors, testing procedures, and design considerations relevant to constructing a structural fill project using CCR. Industry guidance, such as USWAG's "*Engineering and Environmental Guidance on the Beneficial Use of Coal Combustion Products in Engineered Structural Fill Projects*" may also provide information relevant to this issue. Further, some states, such as Wisconsin and Virginia, have developed environmental guidance for evaluating the suitability of a site prior to construction of a CCR structural fill.

While many of these documents do not establish binding requirements, nor is EPA seeking to make them binding on users, they provide evidence of the design and construction practices, including the amounts that are typically used throughout the industry, and provide a basis on which to evaluate whether excessive quantities have been used in a particular application. These types of documents are also relevant in making judgments on the larger question—whether the activity is legitimate reuse or merely sham disposal. In essence, product specifications serve the same function as the requirement suggested by a commenter for a plan to only use what is necessary to reach the desired effect.

Commenters were also concerned that the proposed standards, and particularly this criterion, did not include any provision that would ensure that CCR reuse was protective of human health and the environment. One commenter stated that product specifications and engineering standards do not speak to environmental risk or consumer exposure. This same commenter was concerned that the proposed criteria used circular logic by stating that excess materials were not to be used in cases where specifications or standards have not been established. Another commenter criticized this criterion because it did not include threshold levels that protect public health from the range of toxicants routinely found in coal ash.

EPA generally disagrees that the requirement to ensure that excessive volumes have not been used is unrelated to environmental and safety concerns. Minimizing the amount of material used in a product or released to the environment decreases potential exposures to the material. EPA agrees, however, that an additional criterion that more directly addresses the potential health and environmental risks is appropriate for unencapsulated uses, which present the greater potential for exposures of concern. As discussed in more detail below, the Agency has added a criterion to specifically require users of unencapsulated CCR to demonstrate that environmental and health related standards have been met. The criterion is a general performance standard that is equally applicable to all sites and uses and will account for a wide variety of potential exposures. By contrast, in order to establish toxicant "threshold levels," EPA would need to develop risk assessments that account for the wide variety of potential uses and exposures. This is neither practical nor feasible, given the site specific nature of the potential risks and the myriad of potential uses. In addition, EPA disagrees that this is necessary, as the performance standard laid out in the fourth criterion will appropriately address the risks documented in the current record for these uses.

[44] Commenters argued that, at least in agronomic settings, there is no incentive to use excess amounts because it simply increases the grower's cost.

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Furthermore, as the Agency has previously stated in the May 2000 Regulatory Determination and the 2010 proposal, leaving the Bevill determination in place for beneficial use does not conflict with EPA's view that certain beneficial uses, *e.g.,* use in road construction and agriculture, should be conducted with care, according to appropriate management practices, and with appropriate characterization of the material and the site where the materials will be placed. EPA has concluded that the potential risks of these uses do not warrant federal regulation, but can be addressed, if necessary, in other ways.

State programs exist and have the expertise to address beneficial use applications. In addition, the Agency is currently developing a framework to address the risks associated with the beneficial use of unencapsulated materials. This framework is expected to be finalized in 2015; the framework will be available to assist in the implementation of issues associated with the unencapsulated uses of CCR. The Agency has also been working with the U.S. Department of Agriculture to address the risks associated with the agricultural use of CCR. In conclusion, the Agency believes that sufficient tools are available (or will soon be available) to address the site-specific risks associated with the beneficial use of CCR.

*Criteria 4: When unencapsulated use of CCR involving placement on the land of 12,400 tons or more in non-roadway applications, the user must demonstrate and keep records, and provide such documentation upon request, that environmental releases to groundwater, surface water, soil and air are comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use.* The Agency has established an environmental criterion to protect human health and the environment in response to numerous comments received on the proposal raising concern that additional provisions were necessary to ensure that unencapsulated uses of CCR needed to be conducted in an environmentally protective manner. The Agency discussed in the proposed rule the ways in which the use of CCR in an unencapsulated manner could affect groundwater, surface water, air and be associated with dust emissions. This fourth "environmental" criterion requires potential users to addresses potential risks from all of these pathways in order to avoid compliance with the final disposal requirements. Existing sources of guidance and standards (*e.g.,* ASTM E2277–03 and USWAG's "*Engineering and Environmental Guidance on the Beneficial Use of Coal Combustion Products in Engineered Structural Fill Projects,*" to name just two that are currently available), are available and may provide useful assistance for determining if the use of CCR are comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use. Information (*e.g.,* modeling results, proposed designs, risk assessments, etc.) that have been proposed or developed to comply with state standards that explicitly address the environmental impacts of unencapsulated uses may also be relevant to this determination.

*i. Source of the 12,400 Ton Threshold and Fill Operations.*

As discussed earlier in this section, the fourth criterion was designed to address whether the activity is appropriately considered to be "disposal" and whether that "disposal" warrants regulation. Thus, the final criterion correlates to the practices and the risks at issue: The placement of large quantities of CCR in a single concentrated location, as documented by the 2014 risk assessment and the damage cases.

In the proposed rule, EPA explained that the risks of greatest concern from unencapsulated beneficial uses were associated with the placement of CCR in quarries and sand and gravel pits, and with large scale fill operations used to re-grade the landscape. EPA generally proposed to define these operations as "disposal" rather than "beneficial use." As discussed below, EPA has retained that approach with respect to the placement in sand and gravel pits and quarries; consequently the fourth criterion need not account for these uses. By contrast, EPA has not definitively concluded that "large scale fill operations," per se, constitute the disposal of CCR. This is because EPA agrees with commenters that, if constructed correctly, large scale fill operations can meet all of the criteria for a beneficial use. But EPA also agrees that these applications can present risks to human health and the environment, and therefore has drafted the fourth criterion to specifically address the risks presented by these operations. The fourth criterion is thus tied to the Agency's general approach to large scale fill.

The Agency acknowledged in the proposal that additional guidance was warranted on what would constitute a large scale fill operation, and received numerous comments on this issue in response to the proposal. EPA requested comments again on the topic of large scale fills in a Notice of Data Availability (NODA). 78 FR 46940 (August 2, 2013). The NODA discussed the fact that many commenters on the proposed CCR rule stated that EPA should have developed a size criterion to define large scale fill operations. One commenter suggested 5,000 cubic yards as a size criterion for a CCR landfill, but did not provide a basis for this. Other commenters suggested size criteria but for different reasons than defining disposal criteria; for example, Wisconsin has a standard where all CCR used for unconfined and confined "fill projects exceeding 5,000 cubic yards require concurrence by the State prior to commencement of the project." Similarly, West Virginia stated that "unencapsulated use of CCR as structural fills not exceeding 10,000 cubic yards are approvable on a case-by-case basis."

In the NODA, EPA identified three different types of data sets that could provide information relevant to developing appropriate criteria or to otherwise defining what constitutes a "large scale" fill operation. EPA solicited comment on the adequacy of the data sets and whether EPA should consider them for the purpose of creating criteria or a definition. The three data sets were: (1) The size of the structural fills that have resulted in damage cases; (2) the distribution of landfill sizes, derived either from an EPA Office of Water's questionnaire or from the landfill size distribution used in the proposed rule; and (3) the size distribution for large scale fills that have been constructed in North Carolina. Many commenters argued that it was entirely inappropriate for EPA to specify in the rule when a project constitutes beneficial use simply by volume or amount of structural fill necessary to construct a stable base for a building. Commenters argued that a large scale fill operation, if designed appropriately, constituted a legitimate beneficial use. In fact, industry commenters universally claimed that they were not aware of any damage cases or adverse environmental impacts associated with structural fills that had adhered to industry guidance (*e.g.,* ASTM standard E2277–03 for structural fills and the USWAG *Engineering and Environmental Guidance on the Beneficial Use of CCPs*

*in Engineered Structural Fill Projects*), and argued that the history of well-designed and implemented engineered structural fills demonstrate that CCR can serve as a valuable resource in avoiding disturbing native ground to secure borrow soils where fill materials are needed to establish a final grade for a project site that meets the need of the proposed final use. To this end, the commenters also acknowledged that site characterization and characterization of the CCR are fundamental to the construction of fills across the U.S. Similarly, other commenters stated that size should not be the only criterion used to define large scale fill operations and highlighted that the site conditions, including such features as the hydraulic conductivity of the area, should also be an important criterion to consider. Still other commenters stated that CCR landfills cannot include large scale fill CCR beneficial use projects because such operations do not involve disposal of a solid waste. Rather, industry commenters argue that the determination as to what is disposal as opposed to beneficial use should be a determination that rests solely with state agencies. These commenters suggested that the determination as to whether a particular fill project constituted disposal, rather than beneficial use should be based on a series of factors, and not simply a size-cut-off. Finally, other commenters argued that the Agency incorrectly presumed that only large scale fill operations could cause environmental damage, and suggested that rather than regulating large scale fill operations solely on the basis of the volume or the amount of CCR involved, the information available to EPA from damage cases and monitoring data suggests that an additional, if not primary criteria for regulating fill operations, including those involved in highway construction, should include the prevention of CCR coming into contact with water. Focusing on the risks of concern—that large scale fills were effectively operating as landfills—the Agency reviewed the database of landfills used in the 2014 risk assessment and has established a threshold limit that corresponds to the smallest size landfill in the risk assessment database. EPA selected this threshold as the trigger for requiring an affirmative demonstration by the user that there will be no releases of concern as a consequence of the land application, because the available evidence in the record (*i.e.,* the 2014 risk assessment) demonstrates that at these volumes the potential risks are of such significance to warrant regulation. Based on this evidence, the burden then shifts to the potential user to demonstrate that these potential risks do not exist at the particular site or have been adequately mitigated. Under this approach, unencapsulated beneficial use applications greater than or equal to 12,400 tons can still be conducted without becoming subject to the disposal regulations by using engineering principles, such as a liner system, and demonstrating that environmental releases to groundwater, surface water, soil and air are comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors. EPA agrees that the volume of CCR involved should not be the sole basis for determining whether an operation constitutes disposal. As such, the Agency is requiring the use of the fourth criterion in order to address any potential risks associated with unencapsulated uses of CCR that are in excess of 12,400 tons. Users will be required to make an affirmative demonstration relating to the potential environmental releases and the potential risks of the application (in addition to requiring compliance with the other three criteria). Specifically, users will be required to demonstrate that environmental releases to groundwater, surface water, soil and air are comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use. EPA expects such determinations to take into account a wide variety of factors, including the hydraulic conductivity of the area, proximity of the material to water, and the likelihood of contact with water. EPA also expects that such determinations would take into account, as many commenters acknowledged to be appropriate and necessary, the need for site characterization and characterization of the CCR. The fourth criterion was adopted in part, to address commenters' concern that the EPA should include a criterion that prevents the placement of CCR in water sources. These are legitimate concerns; existing damage cases show that the placement of CCR in sand and gravel pits was almost always associated with CCR being placed in contact with water. The fourth criterion will require the user to demonstrate that environmental releases to groundwater, surface water, soil and air are comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use. As a consequence of this requirement, EPA expects that significant changes may need to be made in order to proceed with a proposed use; for example, conducting the required assessment, may demonstrate that the only way to achieve the performance standard is to install engineering features, such a liner, as part of the proposed project.

Application of unencapsulated CCR to the land in volumes less than the 12,400 tons will not require an affirmative demonstration to be considered a beneficial use. While the Agency has sufficient information to document that unencapsulated uses can present a hazard, based on the current rulemaking record, EPA lacks the information necessary to demonstrate that unencapsulated uses in smaller amounts are likely to present a risk.[45] In other words, the evidence relating to these uses is not sufficient to shift the burden to the potential user to affirmatively demonstrate the safety of the proposed use. Nevertheless, the Agency expects potential users of unencapsulated CCR below this threshold to work with the states to determine the potential risks of the proposed use at the site and to adopt the appropriate controls necessary to address the risks. In this regard, EPA notes that the composition and leaching behavior of CCR being beneficially used may change over time due to upgrades in air pollution controls devices at coal-fired power plants. Further, initial determinations for existing beneficial use (BU) applications may have relied on single-point pH test methods (*e.g.,* TCLP, SPLP) that, depending on actual field conditions in which the applications are occurring, can under- or over-estimate leachate concentrations. Scientific advancements

[45] In November 2014, EPA received reports alleging that extensive groundwater monitoring data collected by the Wisconsin Department of Natural Resources demonstrated a correlation between beneficial uses of unencapsulated CCR below these thresholds and contaminated drinking water wells in southeastern Wisconsin. Insufficient time was available to allow EPA to evaluate these reports as part of this rulemaking. However, EPA will continue to evaluate the issues associated with unencapsulated uses of CCR, and to the extent available data demonstrate the need for revisions to these criteria, EPA will initiate the necessary rulemaking procedures.

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in leach test protocols have found that the degree of leaching can vary by several orders of magnitude. Accordingly, states overseeing CCR BU programs are encouraged to closely evaluate existing BU applications in light of ongoing scientific advances in tools and technologies to ensure these applications remain protective of human health and the environment. In addition, the Agency is working to provide assistance to states and potential users; this includes the release of the Agency's *Industrial Waste Evaluation Model* (IWEM), and the development of a framework for systematically assessing unencapsulated BU applications to aid in assessing whether there are environmental risks associated with site specific structural fills.

*ii. Exclusion of Roadway Applications from the 4th Criterion.* In the 2010 proposal, the Agency stated that the placement of unencapsulated CCR on the land, such as in road embankments, presented concerns, but that the amount and the manner in which they are used—subject to engineering specifications and material requirements rather than landfilling techniques—are very different from land disposal. The Agency highlighted the 2005 guidance that was developed by EPA, FHWA, DOE, ACAA, and USWAG, addressing the appropriate methodologies and engineering requirements for the use of coal ash in highway construction. Lastly, the Agency noted the difference in terms of volume; the difference between the amounts of CCR that could be disposed of in a landfill vs. the amount of CCR used in the construction of a roadbase (typically on the order of six to twelve inches thick).

EPA received a number of comments requesting that the definition of a CCR landfill exclude CCR used in highway and road construction projects and similar beneficial use projects authorized by an appropriate state agency. These commenters reasoned that the "arbitrary cutoff' discussed in the NODA would inappropriately capture such uses.

The Agency has excluded roadways and associated embankments from the fourth criterion because the methods of application are sufficiently different from CCR landfills that EPA cannot extrapolate from the available risk information to determine whether these activities present similar risks. Roadways are subject to engineering specifications that generally specify CCR to be placed in a thin layer (*e.g.,* six to 12 inches) under a road. The placement under the surface of the road limits the degree to which rainwater can influence the leaching of the CCR.

There are also significant differences between the manner in which roadways and landfills can potentially impact groundwater. These include the nature of mixing in the media, the leaching patterns, and how input infiltration rates are generated. First, CCR landfills are typically a homogenously mixed system, and as a result, there are no spatial variations of the chemical and physical properties of the media (for example, bulk density, hydraulic conductivity and contaminant concentration). By contrast, roadways are generally constructed of several layers with different material properties (heterogeneity). This difference affects the hydraulic conductivity of a mass of CCR in a landfill, as compared to CCR placed in an embankment. Any potential leaching will tend to spread over the length of the embankment, as opposed to the leaching in a downward motion that would occur in a homogenously filled landfill.

Finally, (and perhaps most critically) the construction of roads and associated embankments are supervised and approved by State and/or Federal Department of Transportation (DOT) engineers who ensure compliance with engineering specifications

While EPA is exempting roadbed applications of 12,400 tons or larger from the fourth criterion, EPA is mindful of situations where large quantities of CCR have been used without appropriate engineering controls or where placement on the land has apparently far exceeded those necessary for the engineering use of the materials. One such situation occurred in Puerto Rico with CCR generated by the AES Coal Fired Power Plant in Guayama. As discussed in Unit IV.B of this document, CCR and an aggregate created from them ("AGREMAX") were being used as fill in housing developments and in road projects. Over two million tons of this material was used between 2004 and 2012. When made aware of the situation, EPA raised concerns over the use of CCR and AGREMAX based on the fact that the Environmental Quality Board had not imposed engineering controls, specified appropriate uses, or otherwise limited the use of AGREMAX by the end users. Inspections of some of the sites where the material had been placed showed use in residential areas, areas close to wetlands and surface waters and/or over shallow sole source drinking water aquifers. In addition, in some cases the volumes appeared to be in excess of what was necessary for engineering uses and some sites appeared to be abandoned. This kind of situation will be directly addressed by the new beneficial use criteria promulgated in the final rule. To qualify as a beneficial use, the use of AGREMAX would need to meet all four of the criteria—that is, it must provide a functional benefit, substitute for a virgin material, meet product specifications, and in this case, the user would be required to make the environmental demonstration for the non-roadbed applications.

*iii. Kinds of unencapsulated uses of CCR required to comply with the fourth criterion.*

Unencapsulated uses of CCR are numerous and range, in total use, from hundreds of thousands of tons to millions of tons per year. These applications include, as examples, the following: (1) Flowable fill; (2) structural fills; (3) soil modification/stabilization; (4) waste stabilization/solidification; (5) use in agriculture as a soil amendment; and (6) aggregate.

Many of these unencapsulated uses, other than structural fills, are not generally expected to be used in amounts that would require an environmental demonstration under the fourth criterion. And for several of these applications, which can be structurally very different from landfills, EPA expects that even if these applications are used in amounts greater than 12,400 tons, potential users will be easily able to meet the performance standard. For example, the use of CCR for soil modification or stabilization, agriculture, waste stabilization/solidification, aggregate or flowable fill applications, is generally not similar to the mounding that occurs in a landfill situation. These differences can have a tremendous bearing on the leaching potential of the CCR materials.

Structural fills, however, can be larger applications and so may be required to demonstrate compliance with the environmental standards in the fourth criterion more frequently. In addition, because structural fills can be similar to the landfills regulated in the final disposal rule, some proposed applications may need to install engineering features to meet the performance standard.

*iv. Demonstration that "environmental releases to groundwater, surface water, soil and air are comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use."*

The environmental fourth criterion requires a potential use of CCR to compare analogous products or to perform an environmental assessment evaluating whether releases to the environment are at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use. A demonstration should consider the development of a conceptual model to assist in the determination of whether the environmental criteria contained in the definition of the term "beneficial use of CCR" can be demonstrated. Numerous potential pathways exist and these should be evaluated as necessary depending on the potential application of the CCR. Potential exposure pathways include exposure to groundwater, surface water, air, and soils. Generation of dust, leaching to groundwater and surface water, inhalation of mercury, and plant uptake are areas that need to be evaluated. A complete evaluation of the types of releases, the types of exposure and the receptors that may be potentially affected by a potential application will need to be conducted. A screening comparison will need to be performed comparing the concentrations of individual constituents of potential concern to the following benchmarks: human soil ingestion, ecological soil, tap water ingestion, fish ingestion, surface water, sediment, and inhalation. As an example, a user could compare a mercury concentration to a human health screening benchmark with an inhalation value of 300 ng/m$^3$. Existing documents that can be used to gain an understanding of conceptual models, pathways and regulatory limits include: *Risk Assessment Guidance for Superfund, Exposure Factors Handbook, Volumes I, II and III, Risk Assessment Guidance for Superfund Volume I: Human Health Evaluation Manual Part A, Industrial Waste Management Model (IWEM) Technical Backgrounds Document, Exposure Factors Handbook, Human and Ecological Risk Assessment of Coal Combustion Wastes.* In addition, although it is not directly applicable, a potential user of unencapsulated CCR may find it useful to consult the previously mentioned "*Coal Combustion Residual Beneficial Use Evaluation: Fly Ash Concrete and FGD Gypsum Wallboard*" and the "*Methodology for Evaluating Encapsulated Beneficial Uses of Coal Combustion Residuals*" to assist in the determination of whether the unencapsulated CCR is comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use.

After the effective date of the final rule, any potential user of CCR that makes the demonstration in the fourth criterion must keep records and provide such documentation upon request.

b. Placement in Sand and Gravel Pits and Quarries

EPA proposed that, without exception, unencapsulated CCR placed in sand and gravel pits, and quarries should not constitute beneficial use, but disposal. The Agency highlighted a number of damage cases that involved the filling of old, unlined quarries or gravel pits with large quantities of unencapsulated CCR, under the guise of "beneficial use." Because of the damage cases and the concern that in such instances, sand and gravel pits and quarries were essentially operating as landfills, EPA proposed to define the placement of CCR in sand and gravel pits or quarries as land disposal that would be subject to regulation under either of the proposed regulatory options. The proposal specifically defined a *CCR landfill* as a disposal facility or part of a facility where CCR are placed in or on land and which is not a land treatment facility, a surface impoundment, an underground injection well, a salt dome formation, a salt bed formation, an underground mine, a cave, or a corrective action management unit. For purposes of this part, landfills also include piles, sand and gravel pits, quarries, and/or large scale fill operations. Sites that are excavated so that more coal ash can be used as fill are also considered CCR landfills.

Commenters stated that there were numerous examples of harm caused by the unencapsulated "reuse" in sand and gravel pits and quarries, which demonstrate that these unencapsulated uses were merely disposal in disguise, and must be regulated stringently under Subtitle C of RCRA to prevent the risks they pose of contaminating groundwater, surface water, and ecological systems with heavy metals and other harmful pollutants. In particular, they argue that "There have already been at least 13 damage cases caused by the disposal of coal ash in sand and gravel pits or former quarries that led to contamination of water sources and/or ecological damages." Some commenters also agreed that placement in sand and gravel pits and quarries should not be considered beneficial use. For example, one commenter agreed that CCR placement in sand and gravel pits and quarries is "disposal" and not beneficial use while another commenter wrote that it concurs that large-scale fills in quarries in poorly engineered applications can cause negative impacts. Other commenters highlighted that damage cases related to sand and gravel pits and quarries were old practices that no longer take place. These commenters argued that while sand and gravel quarries have been used to dispose of CCR, it is not correct to assume that with proper engineering and environmental standards that CCR cannot be used beneficially to reclaim quarries for uses such as recreational areas, commercial or industrial uses, or to aesthetically improve the characteristics of the land.

EPA is finalizing its proposal that placement of CCR in sand and gravel pits constitutes disposal, rather than beneficial use. The final definition of a CCR landfill explicitly includes placement of CCR in sand and gravel pits and quarries. EPA has adopted this approach because the practice has resulted in numerous damage cases as a result of the highly permeable strata typically present at such sites. Moreover, while the commenters may be correct that "with proper engineering measures, placement in sand and gravel pits and quarries can be conducted safely", they submitted no data to support this contention. The only engineering features the available information demonstrate would be protective are those that have been determined to be necessary for CCR landfills—*i.e.,* composite liners and groundwater monitoring. And in the absence of these features, any future placement in sand and gravel pits and quarries could not meet the performance standard in the fourth criterion: *i.e.,* that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use.

*B. Definitions*

EPA proposed definitions for a number of key terms used in the proposed subtitle D rule that the Agency determined were necessary for the proper interpretation of the proposed requirements, *e.g., coal combustion residuals, existing CCR landfill.* (See 75 FR 35196–97, June 21, 2010.) In addition, EPA also proposed definitions for terms that were specific to certain regulatory requirements, *e.g., seismic impact zone.*

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EPA is finalizing many of the regulatory definitions that were proposed, some with modifications. Several definitions that were proposed have been removed because they are no longer relevant to this rulemaking and a number of new definitions have been added. Specifically, definitions that have been removed from the final rule include: natural water table, probable maximum precipitation, surface water, systemic toxicants and upstream toe. New definitions are discussed in the technical section of the rule for which they apply. The majority of the regulatory definitions contained in the proposed rule have been retained in the final rule, as proposed or with minor clarifying changes. These definitions are codified in § 257.53 and include the following: *acre foot, active life, aquifer, area capacity curves, areas susceptible to mass movement, coal combustion residuals (CCR), displacement, facility, factor of safety, fault, freeboard, groundwater, hazard potential classification, high hazard potential surface impoundment, significant hazard potential surface impoundment, low hazard potential surface impoundment, holocene, hydraulic conductivity, karst terrain, lithified earth material, maximum horizontal acceleration in lithified earth material, new CCR landfill, new CCR surface impoundment, operator, owner, poor foundation conditions, recognized and generally accepted good engineering practices, representative sample, run-off, run-on, sand and gravel pit or quarry, seismic impact zone, state, structural components, unstable area, uppermost aquifer,* and *waste boundary.*

Several definitions received a significant number of comments and upon further evaluation by EPA have been modified to better explain their meaning or intent. This includes the definitions for the following terms: *CCR landfill or landfill, CCR surface impoundment or impoundment, existing CCR landfill* and *existing CCR surface impoundment.* These comments, along with the revisions made in response are discussed in more detail below. In addition, EPA has revised a number of definitions, or added new definitions, to be consistent with revisions made in the corresponding technical requirements. These are discussed in the various sections of the preamble that address the specific technical requirement. For example, as discussed in Unit V of this document, EPA has revised the definition of "independent registered professional engineer or hydrologist" to "qualified professional engineer" to address the concerns raised in comments.

1. Definition of *CCR Landfill*

EPA proposed to define a *CCR landfill* as a disposal facility or part of a facility where CCR is placed in or on land and which is not a land treatment facility, a surface impoundment, an underground injection well, a salt dome formation, a salt bed formation, an underground mine, a cave, or a corrective action management unit. For purposes of this subpart, landfills also include piles, sand and gravel pits, quarries, and/or large scale fill operations. Sites that are excavated so that more coal ash can be used as fill are also considered CCR landfills. (See 75 FR 35239.) The Agency received a significant number of comments on the proposed definition. These comments focused almost exclusively on the inclusion of "large-scale fill operations" and "piles" within the definition of CCR landfill. Regarding large-scale fills, commenters argued that one of the fundamental problems with the proposed definition was that it assumed all CCR placed in large scale fill operations constituted "disposal" of CCR (and that these operations therefore constitute CCR landfills) rather than beneficial use. Commenters further argued that CCR is often used in engineered fills, such as road base and road embankments and that these legitimate beneficial use operations should not be subject to the CCR landfill regulations.

Commenters also argued that "piles" should be omitted from the definition of a CCR landfill for a variety of reasons. Several commenters argued that including the word "pile" was overly broad and insufficiently prescriptive and would inappropriately capture on-going or short-term CCR management activities that did not constitute disposal, such as storage for beneficial use. These commenters also raised concern that including "piles" in the definition of CCR landfill without further clarification or specificity, *i.e.,* when used as part of a beneficial use operation, would negatively affect beneficial use activities. Other commenters raised concern that the term "piles" was too vague, and suggested that whether piles were treated as CCR landfills should be determined by the size of the piles, or the intent for which such piles exist. These commenters suggested the Agency should exclude small piles of CCR that are staged and/or consolidated prior to transport or placement for disposal. These commenters argued that subjecting all CCR piles to all of the landfill requirements was "illogical and inappropriate."

Certain commenters argued that piles should not be regulated under this rule because they do not present a significant risk to the environment, as evidenced by a lack of damage cases. Alternately, other commenters suggested that if EPA were to regulate piles, the Agency should consider a regulatory strategy other than regulation as a CCR landfill. One alternative regulatory strategy suggested was to include an option establishing a limit (*e.g.,* 180 days) on the amount of time that the CCR could be allowed to be maintained in a pile without regulation as a CCR landfill. Another option suggested was to develop a set of reasonable design and operating standards consistent with the uses and risks posed by piles. Such design standards could include the requirement for a low permeability underlayment or base such as asphalt, concrete or a high density polyethylene (HDPE) liner. Operating standards could include such provisions as labeling, and the requirement to remove at least 90 percent of the contents every 90 days, with a full cleanout annually.

EPA believes the suggested option to establish a time limit would be difficult to oversee and verify. States and citizens would have no way to determine when CCR is placed in a pile and when the CCR was subsequently removed. Therefore, EPA is rejecting this suggested option. The suggested option to develop appropriate design and operating standards is essentially the approach EPA has adopted, as discussed in more detail below. However, the final design and operating standards differ according to the management practices, and include measures to control fugitive dust, and for certain practices, require the installation of a composite liner and leachate collection system.

EPA discussed its final approach to large-scale fill operations in Unit V of this document; the definition of a CCR landfill has been revised to be consistent with the approach described in that section. As explained at length, EPA has adopted a final approach that distinguishes between beneficial use and the "disposal" of CCR. Activities that meet the definition of beneficial use are not subject to these regulations. Activities that do not meet all of the criteria in the definition of a beneficial use—and in particular, such activities that involve the placement of unencapsulated CCR on the land—are considered disposal and are subject to the requirements of this final rule. Consistent with this approach the final definition of a CCR landfill has been revised to clarify that it includes "the

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use of CCR that does not meet the definition of a beneficial use of CCR." Waste piles, including those used to temporarily store or manage CCR on-site prior to disposal in a CCR landfill or subsequent beneficial use, have been retained within the definition of a CCR landfill. In making this determination the Agency was strongly influenced by the similarities in the potential risks posed by both waste piles and CCR landfills to human health, groundwater resources, or the air if improperly managed. Both CCR piles and CCR landfills are subject to external factors such as rain and wind, which can adversely affect human health and the environment. For example, uncontrolled run-on and run-off can result in ponding of water in and around the unit resulting in increased leachate which has the potential to affect groundwater. Similarly, absent dust control measures, such as the conditioning of CCR, both CCR landfills and CCR piles have the potential to generate significant amount of fugitive dust. Indeed, CCR piles are generally more susceptible to the creation of fugitive dusts. And contrary to the commenters' contention about the absence of damage cases, the single most frequent issue presented during the public hearings was the allegation by individual citizens of damage caused by fugitive dusts from neighboring CCR facilities. Moreover, the same pollution control measures, such as liners, leachate collection systems, and groundwater monitoring, will address the potential adverse effects from both of these units. As such, the Agency sees no reason to treat piles and landfills differently.

EPA also disagrees that the inclusion of CCR piles would capture on-going or short-term CCR management activities that do not constitute disposal. Irrespective of whether the facility is using the pile as "temporary storage" or ultimately intends to direct the CCR to beneficial use, by placing the CCR on the land with no containment or other method of preventing environmental exposures, the facility is engaging in an activity that clearly falls within the statutory definition of disposal. See 42 U.S.C. 6903(3)("placing of solid waste . . . on any land, so that such solid waste . . . or any constituent thereof may enter the environment.") Moreover, even where the facility intends the pile to be "temporary," some amount of CCR inevitably remains in place. And if this was not the case, under section 1008(a)(3), EPA is authorized to establish criteria governing all aspects of solid waste management—which explicitly is defined to include "storage" as well as all of the other activities identified by the commenters—to ensure the protection of human health and the environment. See 42 U.S.C. 6903(28).

Nevertheless, EPA agrees that not every activity that involves the management of CCR must occur in a unit that meets all of the technical requirements of a CCR landfill (*e.g.,* groundwater monitoring). The key concern EPA is seeking to address with the inclusion of piles is the uncontrolled exposure from the extended, repeated, or indefinite placement of large amounts of unconsolidated CCR directly on the land. To the extent those exposures are controlled, whether through the use of tanks or some other kind of containment measures, the practice is neither considered to be a "pile" nor disposal in a landfill.

To clarify this, and in response to the concern that the term "piles" was too vague, EPA has adopted a definition of the term "CCR pile" to identify those "piles" that are subject to the disposal requirements in this regulation. The final regulation specifies that a CCR pile means any non-containerized accumulation of solid, non-flowing CCR that is placed on the land. This definition mirrors the existing definition of "waste pile or pile" from the part 257 regulations, (*i.e.,* the regulations that currently apply to CCR facilities), as well as the definition in part 260. The use of the phrase "non-containerized" is not intended to require that all activities occur within tanks or containment structures, but merely that specific measures have been adopted to control exposures to human health and the environment. This could include placement of the CCR on an impervious base such as asphalt, concrete, or a geomembrane; leachate and run-off collection; and walls or wind barriers. CCR managed in such a fashion would not be CCR piles and, therefore, not CCR landfills subject to this regulation. To further clarify how this relates to EPA's overall approach to beneficial use it is important to distinguish between CCR that is actually being used beneficially and CCR that may someday be used beneficially. CCR that is currently being used beneficially—for example, fly ash that has been transferred to a cement manufacturer and that is stored off-site in a "temporary pile," and that complies with all of the criteria in the definition to be considered a beneficial use including the fourth criterion relating to the placement of large quantities of unconsolidated CCR on the land—would not be subject to the regulations applicable to CCR disposal. Accordingly, the final regulation specifies that practices that meet the definition of beneficial use of CCR are not subject to the 'disposal" requirements of the rule.

By contrast, CCR located on-site that may someday be used beneficially but is not yet beneficially used remains subject to the disposal rule. Given that landfills and surface impoundments can be periodically dredged to provide material for beneficial use, any other approach would be impracticable, and would exclude from regulation many of the greatest sources of risk. An example of a "pile" that is not yet beneficially used is unconsolidated CCR placed on the land, that have been designated by the CCR facility to be transferred to another location for subsequent beneficial use (*e.g.,* use as road bed) in the near future.

Several commenters also suggested that the definition of a CCR landfill should explicitly exclude the use of CCR at surface coal mining and reclamation operations, to reflect the Agency's intention not to cover such activities. The Agency agrees and has revised the definition to explicitly provide that the term CCR landfill does not include the use of CCR at coal mining and reclamation operations.

Consequently, the Agency is finalizing a definition of "CCR landfill or landfill" that can be found in § 257.73. On a related matter, the definition of CCR landfill or landfill contains the terms "sand and gravel pits or quarries." EPA proposed a "sand and gravel pit and/or quarry" to mean an excavation for the commercial extraction of aggregate for use in construction projects. The Agency received comments on the definition of sand and gravel pit and/or quarry suggesting that the term "commercial extraction" was too narrow. Specifically commenters were concerned it would exclude non-commercial extraction, such as gravel pits operated by municipalities, and exclude metallic mineral mines, nonmetallic mining for other than sand and gravel, and coal mines. EPA agrees that the use of the term "commercial extraction" renders the proposed definition too narrow, as there is no basis for distinguishing between commercial and non-commercial extraction, either because of the risks these activities pose, or any other consideration relevant to this rulemaking. EPA is, therefore, revising "sand and gravel pit and/or quarry" to mean an excavation for the extraction of aggregate, minerals, or metals. The term sand and gravel pit and/or quarry does not include subsurface or surface coal mines.

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2. Definition of CCR Surface Impoundment

EPA proposed to define a CCR surface impoundment to mean a facility or part of a facility which is a natural topographic depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials) which is designed to hold an accumulation of CCR containing free liquids, and which is not an injection well. Examples of CCR surface impoundments are holding, storage, settling, and aeration pits, ponds and lagoons. CCR surface impoundments are used to receive CCR that have been sluiced (flushed or mixed with water to facilitate movement), or wastes from wet air pollution control devices, often in addition to other solid wastes.

The Agency received many comments on the proposed definition of CCR surface impoundment. The majority of commenters argued that the definition was overly broad and would inappropriately capture surface impoundments that are not designed to hold an accumulation of CCR. Commenters were concerned that the proposed definition could be interpreted to include downstream secondary and tertiary surface impoundments, such as polishing, cooling, wastewater and holding ponds that receive only de minimis amounts of CCR. Commenters reasoned that these types of units in no practical or technical sense could be described as units "used to receive CCR that has been sluiced."

Other commenters raised concern that the definition did not differentiate between temporary and permanent surface impoundments. Commenters stated that many facilities rely on short-term processing and storage before moving CCR off-site for beneficial use or permanent disposal and that these units should not be required to comply with all of the technical criteria required for more permanent disposal impoundments.

Upon further evaluation of the comments, the Agency has amended the definition of CCR surface impoundment to clarify the types of units that are covered by the rule. After reviewing the comments, EPA reviewed the risk assessment and the damage cases to determine the characteristics of the surface impoundments that are the source of the risks the rule seeks to address. Specifically, these are units that contain a large amount of CCR managed with water, under a hydraulic head that promotes the rapid leaching of contaminants. These risks do not differ materially according to the management activity (*i.e.,* whether it was "treatment," "storage" or "disposal") that occurred in the unit, or whether the facility someday intended to divert the CCR to beneficial use. However, EPA agrees with commenters that units containing only truly "de minimis" levels of CCR are unlikely to present the significant risks this rule is intended to address.

EPA has therefore revised the definition to provide that a CCR surface impoundment as defined in this rule must meet three criteria: (1) The unit is a natural topographic depression, man-made excavation or diked area; (2) the unit is designed to hold an accumulation of CCR and liquid; and (3) the unit treats, stores or disposes of CCR. These criteria correspond to the units that are the source of the significant risks covered by this rule, and are consistent with the proposed rule. EPA agrees with commenters that relying solely on the criterion from the proposed rule that the unit be designed to accumulate CCR could inadvertently capture units that present significantly lower risks, such as process water or cooling water ponds, because, although they will accumulate any trace amounts of CCR that are present, they will not contain the significant quantities that give rise to the risks modeled in EPA's assessment. By contrast, units that are designed to hold an accumulation of CCR and in which treatment, storage, or disposal occurs will contain substantial amounts of CCR and consequently are a potentially significant source of contaminants. However, EPA disagrees that impoundments used for "short-term processing and storage" should not be required to comply with all of the technical criteria applicable to CCR surface impoundments. By "short-term," the commenters mean that some portion of the CCR is removed from the unit; however, in EPA's experience these units are never completely dredged free of CCR. But however much is present at any given time, over the lifetime of these "temporary" units, large quantities of CCR impounded with water under a hydraulic head will be managed for extended periods of time. This gives rise to the conditions that both promote the leaching of contaminants from the CCR and are responsible for the static and dynamic loadings that create the potential for structural instability. These units therefore pose the same risks of releases due to structural instability and of leachate contaminating ground or surface water as the units in which CCR are "permanently" disposed.

The final definition makes extremely clear the impoundments that are covered by the rule, so an owner or operator will be able to easily discern whether a particular unit is a CCR surface impoundment. CCR surface impoundments do not include units generally referred to as cooling water ponds, process water ponds, wastewater treatment ponds, storm water holding ponds, or aeration ponds. These units are not designed to hold an accumulation of CCR, and in fact, do not generally contain significant amounts of CCR. Treatment, storage, or disposal of accumulated CCR also does not occur in these units. Conversely, a constructed primary settling pond that receives sluiced CCR directly from the electric utility would meet the definition of a CCR surface impoundment because it meets all three criteria of the definition: It is a man-made excavation and it is designed to hold an accumulation of CCR (*i.e.,* directly sluiced CCR). It also engages in the treatment of CCR through its settling operation. The CCR may be subsequently dredged for disposal or beneficial use elsewhere, or it may be permanently disposed within the unit. Similarly, secondary or tertiary impoundments that receive wet CCR or liquid with significant amounts of CCR from a preceding impoundment (*i.e.,* from a primary impoundment in the case of a secondary impoundment, or from a secondary impoundment in the case of a tertiary impoundment), even if they are ultimately dredged for land disposal elsewhere are also considered CCR surface impoundments and are covered by the rule. To illustrate further, consider a diked area in which wet CCR is accumulated for future transport to a CCR landfill or beneficial use. The unit is accumulating CCR, while allowing for the evaporation or removal of liquid (no free liquids) to facilitate transport to a CCR landfill or for beneficial use. In this instance, the unit again meets all three definition criteria, it is a diked area (*i.e.,* there is an embankment), it is accumulating CCR for ultimate disposal or beneficial use; and it is removing any free liquids, (*i.e.,* treatment). As such, this unit would meet the definition of CCR surface impoundment. In all of these examples significant quantities of CCR are impounded with water under a hydraulic head that will be managed for extended periods of time. This gives rise to the conditions that both promote the leaching of contaminants from the CCR and are responsible for the static and dynamic loadings that create the potential for structural instability. These units therefore all pose the same risks of

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releases due to structural instability and of leachate contaminating ground or surface water.

3. Definition of Existing CCR Landfill

EPA proposed to define an existing CCR landfill to mean a CCR landfill which was in operation on, or for which construction commenced prior to the effective date of the final rule. The proposed definition specified that a CCR landfill has commenced construction if the owner or operator has obtained the federal, state, and local approvals or permits necessary to begin physical construction; and either: (1) A continuous on-site, physical construction program has begun; or (2) the owner or operator has entered into contractual obligations—which cannot be cancelled or modified without substantial loss—for physical construction of the CCR landfill to be completed within a reasonable time.

In response to the proposed definition, the Agency received several comments arguing that the use of the phrase "was in operation on, or for which construction commenced prior to" would lead to confusion. Commenters contended that most units defined as CCR landfills at some point in time "were in operation" and had "commenced construction" prior to the effective date of the regulation. Commenters claimed that this definition would unnecessarily capture thousands of closed structural fill projects, including residential properties, commercial properties used by small businesses, and many recreational facilities. Furthermore, commenters doubted that EPA intended for the rule to cover all of these units and urged the Agency to clarify that closed units are excluded from the definition of existing CCR landfill.

Other commenters argued that the proposed definition of *existing CCR landfill* should be modified to include lateral expansions of operation units where such an expansion is within the site footprint of an area already approved and permitted by the state for the landfill. Commenters contended that while the proposed definition included undeveloped areas within the footprint of an approved permitted site, it also required that the construction be initiated at the site or that some type of binding contractual obligation be present. Commenters contended that the existence of a contractual obligation unfairly subjects undeveloped, yet approved permitted areas to design and operating standards for new CCR landfills based merely on the existence of a contract to commence construction. Commenters argued that such a distinction was arbitrary and capricious and provided no practical benefit. Other commenters questioned the usefulness of requiring a contractual obligation at all. As written, the commenters argued, that the definition was vague, unenforceable, and thus, not protective of human health and the environment. Commenters reasoned that there was no definitive or generally accepted meaning for the term "substantial loss" or the term "reasonable time" and an owner or operator, sensing that these proposed rules may be passed, could sign a contract now with minimum predetermined cancellation or modification penalties and a contract term of say five years or even longer to avoid the new unit requirements, *i.e.,* a composite liner.

The commenters are correct that EPA did not intend to cover inactive landfills under this rule. The Agency agrees that, as drafted, the proposed definition could cause confusion. EPA therefore deleted the phrase "was in operation on the effective date of the rule" and has substituted the phrase "that receives CCR both before and after [the effective date of the rule]." EPA also agrees that the phrase "commenced construction prior to the effective date of the rule" could similarly cause confusion. Therefore, the Agency has made a similar revision, by adding the phrase "and receives CCR on or after [the effective date of the rule]" after the phrase "for which construction commenced prior to [the effective date of the rule]." These revisions will clarify which units are covered by the technical requirement of the rule and alleviate any confusion. EPA is also making conforming modifications to the definition of *existing CCR surface impoundment.*

EPA disagrees that lateral expansions should be considered to be "existing" based solely on the fact that such an expansion is within the site footprint of an area already approved and permitted by the state. EPA has frequently distinguished between the types of requirements applicable to new and existing units, reasoning that in many instances, risk mitigation measures would be adequate such that existing units need not wholly retrofit to meet the new "state of the art." For new units, however, the balance is generally struck in favor of requiring a greater degree of risk prevention, rather than relying solely on risk mitigation measures. In determining whether a unit is "new" or "existing," EPA has historically considered that the equities lie in favor of considering a unit to be "existing" when there has been an irretrievable commitment of resources on the part of the facility. That has not occurred merely because permits have been obtained. While admittedly resources have been committed, at this stage modifications to the design and construction of the unit are still feasible. Specifically, the critical differences between the requirements applicable to new and existing CCR landfills are the type of liner that must be installed and the location restrictions that apply. Compliance with these requirements can be addressed through modifications to the design and construction of the unit, and are therefore readily feasible until construction has begun.

EPA agrees with those commenters who were concerned that the phrase, "the owner or operator has entered into contractual obligations—which cannot be cancelled or modified without substantial loss—for physical construction of the CCR landfill to be completed within a reasonable time," is vague and potentially subject to abuse. While this phrase has been included in other EPA regulations, those regulations operate within a regulatory program overseen by a regulatory authority. No similar guarantee exists under these regulations. EPA could not discover a definitive or generally accepted meaning for the terms "substantial loss" or "reasonable time," or develop sufficiently objective and determinate criteria for these concepts. Consequently, the Agency has decided to remove this provision from the definition of *existing CCR landfill.* EPA is retaining the two most important elements of the definition that will effectively determine whether the facility has irretrievably committed resources such that it would not reasonable to require compliance with all of the requirements applicable to new units. Accordingly, a unit will be considered to be existing if, first, the owner or operator has obtained the federal, state, and local approvals or permits necessary to begin physical construction; and second, that a continuous on-site, physical construction program has begun (*i.e.,* groundbreaking has occurred). Therefore, EPA is finalizing the definition of *existing CCR landfill* that can be found in § 257.53.

4. Definition of *Existing CCR Surface Impoundment*

EPA proposed to define an *existing CCR surface impoundment* to mean a surface impoundment which was in operation on, or for which construction commenced prior to the effective date of the final rule. The proposal also specified that a CCR surface impoundment has commenced

construction if the owner or operator has obtained the federal, state, and local approvals or permits necessary to begin physical construction; and either: (1) A continuous on-site, physical construction program has begun; or (2) the owner or operator has entered into contractual obligations—which cannot be cancelled or modified without substantial loss—for physical construction of the CCR landfill to be completed within a reasonable time.

EPA received many of the same comments on the definition of an existing CCR surface impoundment that were received on an existing CCR landfill. This included comments requesting clarification that the term did not include impoundments that had ceased receiving CCR before the effective date of the rule. Commenters also suggested that EPA modify the definition to include the phrase that the surface impoundment "was in operation and had not yet ceased receiving CCR prior to the effective date of the rule" to make clear that the definition did not encompass units that are no longer receiving CCR on the effective date of the rule, even though the unit may not have completed final closure prior to the rule's effective date. Commenters reasoned that units no longer receiving CCR on the effective date of the rule are not "in operation" and therefore should not be subject to the standards applicable to active units. Commenters also requested that EPA clarify that the definition of "existing CCR surface impoundment" include units that were in operation on the effective date of the rule and that periodically dredged out during the operating life of the impoundment. Commenters contended that while this may seem self-evident, EPA needed to clarify that these impoundments would not be characterized as "new CCR surface impoundments."

The Agency is generally conforming the definition of an existing CCR surface impoundment to the revised definition of an existing CCR landfill. Although inactive CCR surface impoundments are covered by the final rule (unlike inactive CCR landfills), EPA decided it would provide greater clarity to establish a section specific to inactive CCR surface impoundments rather than merely including such units within the definition of an existing CCR surface impoundment. As discussed in greater detail in Unit VI.A of this document, under § 257.100, any CCR surface impoundment that continues to impound CCR and water after the effective date of the rule, must either (1) breach, dewater, and place a cover on the unit within three years or (2) must comply with all of the requirements applicable to existing CCR surface impoundments. Without the need to account for inactive CCR surface impoundments within the definition, the definitions of "existing" landfills and surface impoundments should be the same.

Thus, the Agency has removed the term "in operation" from the definition and has instead focused on when the surface impoundment received or will receive CCR. EPA has also deleted the provision that would have allowed a unit to be considered to be "existing" based on the existence of a contract. Accordingly, for purposes of this rule, a CCR surface impoundment will be considered to be "existing" if the unit received CCR both before and after the effective date of the rule. For example, if a CCR surface impoundment received CCR prior to the effective date and was in the process of dredging on the effective date with the intent of receiving additional CCR after the effective date, the unit would still be considered to be an "existing" rather than a new unit. Conversely, if a unit received CCR prior to the effective date and was no longer receiving CCR, this unit would be considered "inactive," and would only be subject to the technical criteria applicable to "existing" CCR surface impoundments if they had not completed closure within three years. Similarly, if a CCR surface impoundment had commenced construction prior to the effective date with the intention of receiving CCR on or after the effective date of the rule, the unit would be considered an "existing" unit only if the physical construction program had begun (*e.g.,* groundbreaking had occurred) with the appropriate federal, state and local approvals or permits in place. But if prior to the effective date of the rule, the permits had been obtained but the physical construction of the unit had not begun (*e.g.,* groundbreaking had not occurred), the unit would be considered "new" and would be subject to all the applicable technical criteria for new CCR surface impoundments. Therefore, the Agency is finalizing the definition of *existing CCR surface impoundment* that can be found in § 257.53.

### *C. Location Restrictions and Individual Location Requirements*

In the proposed rule, EPA stated that any RCRA subtitle D regulation would need to ensure that CCR landfills, CCR surface impoundments and all lateral expansions were appropriately sited to ensure that no reasonable probability of adverse effects on health or the environment from the disposal of CCR would occur. Under the subtitle D option, EPA proposed location restrictions for CCR units which included requirements relating to the placement of CCR in five general locations: (1) Above the natural water table; (2) wetlands; (3) fault areas; (4) seismic impact zones; and (5) unstable areas. The proposed requirements relied in large measure, on the record EPA developed to support the 40 CFR part 258 requirements for MSWLFs and on EPA's Guide for Industrial Waste Management (EPA530–R–03–001, February 2003). EPA also chose to add one additional location restriction that would ban the placement of CCR units within two feet of the upper limit of the natural water table. This proposed requirement was originally included in the proposed rule, *Standards for the Management of Cement Kiln Dust* (64 FR 45631, August 20, 1999) because of the potential damage to groundwater caused by the management of cement kiln dust at sites located below the natural water table. While the proposed cement kiln dust rule has not yet been finalized, EPA extended this reasoning to CCR by applying the same location restriction to CCR units. The proposed applicability of these location requirements varied depending on whether the unit was an existing or new CCR landfill, an existing or new CCR surface impoundment, or a lateral expansion of such units. For example, for existing CCR landfills, the Agency proposed that only the location requirement for unstable areas would apply. By contrast, the proposed rule applied all of the location restrictions to new CCR landfills and all CCR surface impoundments, both existing and new—an approach consistent with RCRA subtitle C and Congressional distinctions between the risks presented by landfills and surface impoundments. (See 75 FR 35198–35199.) This meant that owners or operators would need to close existing CCR surface impoundments located less than two feet above the natural water table, or for existing CCR units in sensitive but not prohibited locations, make a technical demonstration that the unit met the requirements of a performance standard that serves as the alternative to the location restriction, retrofit the unit so that it could meet the performance standard, or close. For those CCR units that need to close (*i.e.,* owners or operators that could not make the necessary technical demonstrations), EPA proposed that the unit must close within five years of the effective date of the rule. If closure could not occur within the five year timeframe, the

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Agency proposed allowing for a case-by-case extension for up to two more years if the facility demonstrated that there was no alternative disposal capacity and no immediate threat to health or the environment.

EPA proposed not to impose all of the location requirements on existing CCR landfills based on the conclusion that CCR landfills pose less risk and are structurally less vulnerable than existing CCR surface impoundments. EPA also raised concern that a significant number of these CCR landfills could be located in areas subject to these requirements, (particularly wetlands), which could cause disposal capacity shortfalls in certain regions of the U.S., if existing CCR landfills in these locations were required to close. Disposal capacity shortfalls can pose significant environmental and public health concerns based on the potential for significant disruption of solid waste management state-wide from the closure of these units. EPA concluded that these risks would be greater than the potential risks from allowing existing CCR landfills to remain in these locations, given that these units would be subject to all of the design and operating requirements of the rule. To ensure the accuracy of its preliminary conclusions, the Agency requested commenters to provide any available information regarding the number of existing CCR landfills located in these sensitive areas. The Agency also sought information regarding the extent to which CCR landfill capacity would be affected by applying all of the location restrictions to existing CCR landfills, the extent to which facilities could comply with the proposed performance standards, and the costs that would be incurred to retrofit existing CCR landfills to meet these standards.

The Agency received numerous comments in response to the Agency's request for additional information regarding the extent to which landfill capacity would be affected by applying all the proposed subtitle D location restrictions to existing CCR landfills. Commenters generally agreed with the Agency that applying the other location restrictions to existing CCR landfills would cause a significant decrease in disposal capacity across the country, although they did not provide any data or information which would support this concern. Commenters noted, however, that if existing CCR landfills located in these areas were to close, it would greatly complicate operations at many utilities. Affected facilities would need to find additional disposal capacity, which would require utilities to procure new real estate on which to site a new CCR landfill (which may be a significant distance from a power plant), obtain a new disposal permit for the CCR landfill (which can take an extended period of time), and potentially transport significant volumes of CCR great distances to newly-permitted facilities. Commenters argued that there was simply no environmental basis for causing this level of disruption to utility CCR disposal practices.

EPA received no data or information in response to the Agency's request for the costs associated with retrofitting a CCR surface impoundment or CCR landfill to meet the demonstrations for existing units. Similarly, the Agency received little to no information in response to EPA's request for additional information on the location of these facilities. Some commenters acknowledged that specific states were located in some of these restricted areas but did not provide specific information on specific units.

Overwhelmingly, the issue receiving the most comment was EPA's intention to subject existing CCR surface impoundments to all of the new location criteria. Commenters contended that subjecting existing units to all of the location criteria was a radical departure from the location restriction provisions of the existing MSWLF rules on which the subtitle D option is based (*i.e.,* existing MSWLFs are only subject to the floodplains and unstable areas restrictions) without any justification for regulating CCR surface impoundments more stringently than existing CCR landfills. Commenters argued that EPA must demonstrate that there are increased risks posed by each CCR surface impoundments based on its location; otherwise, they claimed, there was no justification for EPA to subject CCR surface impoundments to more stringent location restrictions. Some commenters suggested that a more reasonable approach would be to limit the restrictions for existing CCR surface impoundments to unstable areas, consistent with the approach proposed for existing CCR landfills. Finally, commenters raised concern about the inconsistency between the preamble language and the corresponding regulatory text. Specifically, the preamble stated EPA's intention to apply all of the location criteria to all CCR surface impoundments (existing and new) while the proposed regulatory language applied all location criteria only to new CCR surface impoundments and lateral expansions.

1. Applicability of the Location Criteria to Existing CCR Surface Impoundments

EPA acknowledges the discrepancies between the preamble language and the regulatory text regarding the proposed regulatory language for the location restrictions as it applies to existing CCR surface impoundments. In the proposed rule, the regulatory language should have included, "all surface impoundments" as opposed to only "new surface impoundments."

EPA disagrees that in order to justify national minimum standards applicable to existing CCR surface impoundments, the Agency must demonstrate an adverse impact to human health and the environment from each individual unit, based on the specific risks posed at each location. As an initial matter, it is well established that an agency may regulate a class of similarly situated entities through rulemaking, rather than on the basis of an individualized assessment of every entity that will be subject to the rule. And indeed, Congress specifically directed EPA to proceed by rulemaking to establish minimum national standards under RCRA sections 1008(a) and 4004(a). Moreover, section 4004(a) does not require a demonstration of actual impacts, merely that these units present an unacceptable *risk* of harm. Thus, it is sufficient for EPA to establish a factual record demonstrating that the specific location restrictions in the final rule are necessary for CCR units (landfills and surface impoundments), as a class, to ensure that there will be no reasonable probability of adverse effects on health or the environment. As discussed in greater detail in the next section and in Unit X of the preamble, the factual record supports the need for all of the location standards for existing CCR surface impoundments imposed by this rule.

The Agency also rejects the suggestion that EPA establish the same location restrictions for both existing CCR landfills and CCR surface impoundments. As laid out in the proposal and elsewhere in this final rule in greater detail, the risks associated with CCR surface impoundments are substantially higher than the risks associated with CCR landfills, by approximately an order of magnitude. Surface impoundments are utilized by 45 percent of coal-fired power plants and in 2000 accounted for disposal of one-third of all CCR generated.[46] Unlike landfills, CCR surface impoundments

[46] Rowe, C.L., Hopkins, W.A., Congdon, J.D., 2002. Ecotoxicological Implications of Aquatic Disposal of Coal Combustion Residues in the United States: A Review. Environmental Monitoring and Assessment, Vol. 80, pp. 207–276.

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contain slurried residuals that remain in contact with ponded waters until closure. In a statewide investigation of impacts to groundwater quality from CCR disposal sites, the Wisconsin Department of Natural Resources reported that closed sites which originally contained sluiced coal-combustion residuals displayed extremely elevated mean arsenic levels (as high as 364 µg/l).[47] The highest contaminant concentrations in the study were associated with sluiced CCR residuals. In addition, releases of toxic contaminants to surface water and groundwater from mostly unlined CCR surface impoundments and ponds are a relevant factor in 34 of 40 cases of proven damage to the environment (as well as in several cases of "potential" damage to the environment) from mismanagement of CCR.[48] In many of these cases, effluent discharges from the surface impoundments caused significant ecological damage to aquatic life in nearby streams and wetlands. In one case, in 2002, the structural stability of a CCR surface impoundment was directly compromised by sinkhole development, leading to the release of 2.25 million gallons of CCR slurry. In another, an unusually weak foundation of ash and silt beneath a CCR surface impoundment (*i.e.,* man-made unstable ground) was identified as one of several likely factors contributing to the dike failure that in 2008 resulted in the largest CCR spill in United States history.

Unlike RCRA subtitle C, subtitle D does not explicitly authorize EPA to establish different standards for existing and new units, and Congress specifically intended subtitle D to address the risks from existing, abandoned "open dumps." In the proposed rule preamble, EPA explained the rationale for applying these provisions to existing CCR surface impoundments, and the commenters have submitted nothing to rebut that rationale. Thus, EPA maintains its determination that application of the location standards to existing CCR surface impoundments is necessary to achieve the standard in section 4004(a). Absent these location restrictions, the risk of impacts to human health and the environment from releases from CCR units, including from the rapid and catastrophic destruction of CCR surface impoundments, sited in these sensitive areas would exceed acceptable levels. Given that the risks associated with CCR surface impoundments are substantially higher than the risks posed by CCR landfills, this is the appropriate regulatory course for existing CCR surface impoundments.

In this rule, EPA is finalizing location restrictions that will ensure that CCR units are appropriately sited, that the structure of the CCR unit will not be adversely impacted by conditions at the site, and that overall there will be "no reasonable probability of harm to human health or the environment" due to the location of the CCR unit. EPA is finalizing different sets of location restrictions depending on whether the unit is a CCR landfill or CCR surface impoundment and whether it is an existing or new unit. Lateral expansions fall within the definitions of new units and are treated accordingly. These standards provide minimum national siting and performance criteria for all CCR units. The location restrictions under § 257.60 through § 257.64 include: (1) Placement above the uppermost aquifer; (2) wetlands; (3) fault areas; (4) seismic impact zones; and (5) unstable areas. Each of these locations is generally recognized as having the potential to impact the structure of any disposal unit negatively and as such, increase the risks to human health or the environment through structural failures or leaching of contaminants into the groundwater. Under the final rule and as proposed, new CCR landfills, existing and new CCR surface impoundments, and all lateral expansions will be required to comply with all of the location restrictions. Existing CCR landfills however, will be subject to only two of the location restrictions—floodplains, and unstable areas. As noted in the proposed rule, and restated here, existing landfills and surface impoundments are already subject to the location standards in subpart A of 40 CFR part 257 for floodplains, endangered species and surface waters. The final rule does not change this requirement, and so facilities should already be in compliance. The Agency is finalizing, as proposed, the unstable area location restriction for existing CCR landfills because the record clearly shows that failure of CCR units in these areas (*e.g.,* due to instabilities in Karst terrains) have and in all likelihood would continue, in the absence of the restrictions in the final rule, to result in damage caused by the release of CCR constituents, affecting both groundwater and surface waters. As the Agency stated in the proposed rule, the impacts resulting from the failure of CCR units from location instability are of far more concern than any disposal capacity concerns resulting from the closure of existing CCR units in unstable areas.

Conversely, and also consistent with the proposed rule, EPA is not applying the following location restrictions to existing CCR landfills: The requirement to construct a unit with a base located no less than 1.52 meters (five feet) above the upper limit of the uppermost aquifer, as well as the siting restrictions applicable to wetlands, fault areas, and seismic impact areas. Existing CCR landfills pose lower risks and are structurally less vulnerable than existing CCR surface impoundments. In addition, disposal capacity shortfalls, which could result if existing CCR landfills in these locations were required to close, raise greater environmental and public health concerns than the potential failure of the CCR landfills in these locales.

2. Placement Above the Uppermost Aquifer

Under § 257.60(a) EPA is requiring new CCR landfills, existing and new CCR surface impoundments and all lateral expansions to be constructed with a base that is located no less than 1.52 meters (five feet) above the uppermost aquifer, or to demonstrate that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the CCR unit and the uppermost aquifer due to normal fluctuations in groundwater elevations (including groundwater elevations during the wet season). Existing surface impoundments that fail to achieve this standard must close. New CCR landfills, new CCR surface impoundments and all lateral expansions of existing and new CCR landfills and CCR surface impoundments cannot be constructed unless they meet one of these two standards. In response to comment, the Agency has modified the criteria in two ways. First, EPA has replaced "a base that is located a minimum of two feet above the upper limit of the natural water table" with "a base no less than 1.52 meters (five feet) above the uppermost aquifer." EPA received comment explaining that fluctuations in groundwater levels in many geological settings can exceed ten feet over the course of the year, and alleging that the proposed two foot minimum buffer between the base of the unit and the top of the water table would therefore be insufficiently protective. The

[47] Zillmer, M. and Fauble, P., 2004. Groundwater Impacts from Coal Combustion Ash Disposal Sites in Wisconsin. Waste & Materials Management, Wisconsin Department of Natural Resources, PUB–WA 1174 2004.

[48] Cases of damage attributable to disposal of coal combustion residuals are summarized in the appendix to the preamble of the proposed rule, 75 FR 35230–35239, June 21, 2010, and can be found in the RCRA Docket.

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commenter recommended that the minimum vertical separation be at least three to five feet from the base of the liner components. After additional research, EPA is finalizing a minimum buffer of five feet instead of two feet. EPA's research confirmed the commenter's claims. In addition, EPA determined that several states consider five feet between the base of the surface impoundment and the top of the uppermost aquifer to be the minimum distance that is protective of human health and the environment. These are California, Michigan, Nebraska, New York, West Virginia, and Wisconsin. The Agency has concluded from geographic and climatic spacing of these states that the hydrogeologic conditions within them encompass the range of conditions found in the United States. Therefore, EPA is finalizing a minimum buffer of five feet instead of two feet.

EPA is also clarifying the definition of the natural water table. As some commenters noted, there are many factors (hydrologic and geologic settings, nearby pumping, etc.) that influence the location of the groundwater table making it difficult to determine the "natural" level. In addition, as noted, local site-specific hydrogeologic conditions within the aquifer may cause the natural groundwater table to exceed five feet and vary as much as ten feet. To account for the possibility of such large seasonal fluctuations, EPA is revising the definition of "uppermost aquifer" to specify that the measurement of the upper limit of the aquifer must be made at a point nearest to the natural ground surface to which the aquifer rises during the wet season. This definition of "uppermost aquifer" will encompass large seasonal variations, and is a more appropriate parameter than "seasonal high groundwater table" as suggested by several commenters and the proposed "natural water table" because it is more clearly defined.

In § 257.60(a) the term *uppermost aquifer* has the same definition as under the general provisions of § 257.40: The geologic formation nearest the natural ground surface that is an aquifer, as well as lower aquifers that are hydraulically interconnected with this aquifer within the facility's property boundary. This definition includes a shallow, deep, perched, confined or unconfined aquifer, provided it yields usable water. Although EPA originally proposed that all CCR surface impoundments be located ". . . above the upper limit of the natural water table", the Agency is amending this requirement and replacing "water table" with "uppermost aquifer" to make it consistent with the way natural underground water sources are described elsewhere in the rule. EPA made a second revision to the criteria that were originally proposed. As an alternative to requiring that the CCR units described in this section be constructed with a base that is located no less than five feet above the uppermost aquifer, owners and operators may instead demonstrate that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the CCR unit and the uppermost aquifer due to normal fluctuations in groundwater elevations (including groundwater elevations during the wet season).

This alternative standard was developed in response to concerns from commenters that a single depth to the aquifer failed to account for the wide variations in the level of water table fluctuations in different regions of the country. For example, arid regions of the country, such as Arizona, under normal conditions generally do not experience the same degree of fluctuations in groundwater elevations as more temperate regions, such as Minnesota. Accordingly, EPA developed an alternative performance standard focused on the conditions identified in the damage cases and the risk assessment that this location criterion was designed to prevent: Specifically, where the groundwater elevation is high enough to intersect the base of the waste management unit. In such situations, this hydraulic connection can enhance the transport of contaminants of concern from the CCR unit into groundwater. By requiring owners and operators to ensure that these conditions do not occur, the alternative standard to allow owners and operators to account for situations where there are relatively small variations in groundwater levels and a buffer of five feet is not necessary. This will also ensure that a CCR unit need not address situations where an infrequent, unexpected event (*e.g.,* hurricane) could cause a brief, temporary condition where the uppermost aquifer rises to less than the prescribed five feet but which would not in and of itself constitute a long-term threat to the aquifer. However, where normal fluctuations in groundwater elevation (including, but not limited to, seasonal or temporal variations, groundwater withdrawal, mounding effects,[49] etc.) will result in the failure of the unit to meet the performance standard (*i.e.,* no intermittent, recurring, or sustained hydraulic connection between the base of the CCR unit and the uppermost aquifer), the unit must close.

In some recent damage cases, placement of large volumes of CCR into highly permeable strata in the disposal area promoted CCR-water interactions. For example, from 1995 to 2006 in Anne Arundel County, Maryland 4.6 million tons of CCR were placed directly in two sand and gravel quarries without a geomembrane liner or leachate collection system. Rainwater infiltration into exposed CCR coupled with groundwater-CCR interactions and the transmissivity characteristics of local strata contributed to rapid migration of heavy metals, including antimony, arsenic, cadmium, nickel, and thallium to residential drinking water wells located near the mine pits and significant deterioration of water quality as a result of placement of CCR. Similarly, from 1980 to 1997 in Lansing, Michigan, around 0.5 million tons of coal ash was dumped for disposal into a gravel pit with an elevated water table. A remedial investigation has established that groundwater mounding has immersed the CCR into the upper aquifer resulting in on-site exceedances of groundwater quality protection standards for sulfate, manganese, lead, selenium, lithium, and boron. Placement of CCR into un-engineered, unlined units in permeable strata has plainly led to adverse impacts to groundwater. The phrase "normal fluctuations" has been used to clarify that EPA does not intend for the facility to account for extraordinary or highly aberrant conditions (*e.g.,* one-in-a million or "freak" events). Normal fluctuation can include those resulting from natural as well as anthropogenic sources. Natural sources that could affect groundwater levels include, but are not limited to precipitation, run-off, and high river levels. Anthropogenic sources that could affect groundwater levels include groundwater withdrawal, pumping, well(s) abandonment, and groundwater mounding. In satisfying this location restriction, it may be necessary for a professional engineer to model these effects before he can make the necessary certifications.[50] EPA also

[49] A phenomenon usually created by the recharge of groundwater from a manmade structure, such as a surface impoundment, into a permeable geologic material, resulting in outward and upward expansion of the free water table. Mounding can alter groundwater flow rates and direction; however, the effects are usually localized and may be temporary, depending upon the frequency and duration of the surface recharge events.

[50] For example, evaluations can be done to estimate groundwater mounding such as *pubs.usgs.gov/sir/2010/5102/, www.groundwatersoftware.com/calculator_9_*

notes that this modeling may include the same considerations already evaluated under some state programs.[51] EPA expects that owners and operators will have sufficient information to determine whether their CCR unit meets either performance standard. Most, if not all, of this information would be information a facility would typically have as part of normal operations (*e.g.,* the depth of the CCR unit itself), or that will be developed as part of implementing other rule requirements. For example, through the groundwater monitoring system required under §§ 257.90–257.98, the facility can obtain water level measurements in a sufficient number of locations (*e.g.,* monitoring wells, piezometers) to use in determining whether they satisfy either performance standard. Similarly, under § 257.91 a thorough characterization of the geology and hydrogeology of the site must be conducted. Finally, EPA notes that available technology and guidance are available for using existing groundwater monitoring wells, like those required under this final rule, to measure groundwater levels.[52]

3. Wetlands

In § 257.61 of this rule, EPA is finalizing the regulatory text essentially as proposed. Specifically, EPA is adopting a prohibition on locating all CCR surface impoundments and new CCR landfills, as well as lateral expansions of existing CCR units, in wetlands as defined in 40 CFR 232.2, absent specific demonstrations made by the owner or operator that ensure the CCR unit will not degrade sensitive wetland ecosystems. These provisions place the burden of proof for these demonstrations directly on the owner or operator (the discharger). The owner or operator must make the results of these demonstrations available in the facility record. Failure to make any of the demonstrations will bar siting of the CCR unit in a wetland.

In 2003, disposal of CCR in natural or man-made aquatic basins accounted for nearly one-third of all CCR land disposal. Historically, aquatic disposal of CCR has been attractive economically to facilities because of its lower overall cost relative to dry management and the ease of handling of residuals. During aquatic disposal, CCR is commonly piped as a slurried mixture to surface impoundments designed to retain the solids in contact with water for the life of the unit. Particulate solids from the waste stream gravitationally settle while clarified waters ultimately discharge into nearby streams and wetlands.

The term 'wetlands' refers to those areas inundated or saturated by surface or groundwater at a frequency and over a duration sufficient to support a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands include marshes, swamps, bogs and similar areas that are commonly located between open water and dry land. Under the CWA, wetlands are considered 'special aquatic sites' deserving of special protection because of their ecologic significance. Wetlands are very important, fragile ecosystems that must be protected, and EPA has long identified wetlands protection as a high priority.

Undisturbed, natural wetlands provide many benefits to society by improving water quality, providing essential breeding, rearing, and feeding grounds for fish and wildlife, reducing shoreline erosion, and absorbing flooding waters and pollution. Wetlands are also commercial source areas of products for human use such as timber, fish, and shellfish. Recreational hunters harvest wetland-dependent waterfowl. Wetland environments, however, may be adversely impacted by releases of wastes from co-located industrial facilities. Wetland ecosystems can be degraded by accidental discharges that can change the habitat value for fish and wildlife by obstructing surface water circulation patterns, altering substrate elevation, dewatering, or permanent flooding.

In support of the provisions finalized in this rule, EPA is citing several damage cases, including 30 cases of "proven" damage to the environment that involve aquatic disposal of CCR, 14 of which involve impacts to wetlands from release of CCR. For example, at the Hyco Reservoir in Roxboro, North Carolina from 1966 to 1990 the lake received contaminated effluent from coal ash disposal basins that were authorized by National Pollutant Discharge Elimination System (NPDES) permits under the CWA. High levels of the trace element selenium bioaccumulated in aquatic food chains (phytoplankton), poisoning invertebrates and fish in the lake, particularly species of sport fish (bluegill, largemouth bass), causing reproductive failure and severe declines in fish populations in the late 1970's and early 1980's. Consequently, from 1988–2001 the North Carolina Department of Health and Human Services (NCDHHS) issued a consumption restriction advisory for selenium contamination in fish from the reservoir. In 1990, a dry ash handling system was implemented resulting in lower selenium discharge and reduced mean selenium concentration in reservoir waters. As of 2005, concentrations of selenium in fish tissues remained above a toxic threshold even with reduced influx of selenium, due to migration of the element from contaminated sediments to benthic food chains. The total monetized value of damage can be divided among ecologic factors (*e.g.,* major impacts on fish), recreational factors (*e.g.,* fishing trips not taken), depreciated real estate values, aesthetic factors, and human health damages (*e.g.,* losses due to stress and anxiety from knowing ecosystem is poisoned) and is estimated at $877 million.[53]

Although this consideration is not relevant for purposes of establishing the minimum national criteria under RCRA sections 1008(a) and 4004(a), the rulemaking record demonstrates that the monetary cost of environmental damage from releases of CCR at surface impoundments could be considerable. A report on the environmental damage caused by releases of CCR at 22 sites estimates the total cost of poisoned fish and wildlife at the surface impoundment sites at $2.32 billion. At twelve of these sites the releases were legally permitted under the CWA. Five of the 22 cases were caused by structural failures, two resulted from an unpermitted discharge, and one was from a landfill.[54] Effluent contaminated with coal combustion residues is directly linked with high loadings of toxic metals in the discharge areas of aquatic basins, where some metals (primarily arsenic, cadmium, chromium, copper, lead, and selenium) have accumulated in aquatic food chains.[55] In a research overview (literature synthesis) on the environmental effects of disposal of CCR, Rowe et al. (2002) listed adverse biological responses, including histopathological, behavioral, and physiological (reproductive, energetic, and endocrinological) effects, that have been observed in some vertebrates and invertebrates following exposure to and bioaccumulation of CCR-related contaminants.

Under the criteria finalized in this rule, in order to locate a CCR unit or

*hantush_mounding.htm*, and *www.ndwrcdp.org/documents/wu-ht-02-45/wuht0245_electronic.pdf.*

[51] See, *e.g., dnr.wi.gov/topic/stormwater/standards/gw_mounding.html.*

[52] See, *e.g.,* U.S. EPA (Environmental Protection Agency). 2013. Groundwater Level and Well Depth Measurement. SESDPROC–105–R2. Region 4. Athens, GA. Available online at: *www.epa.gov/region4/sesd/fbqstp/Groundwater-Level-Measurement.pdf.*

[53] Lemly, A.D. 2010. Op.cit.

[54] Lemly, A.D.2010. Op. cit.

[55] Rowe, C.L. et. al. 2002. Op. cit.

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lateral expansion in a wetland, the owner or operator must: (1) Successfully rebut the presumption that an alternative site (*i.e.,* one that does not involve a wetland) is reasonably available for the CCR unit or lateral expansion; (2) show that the construction or operation of the unit will not cause or contribute to violations of any applicable state water quality standard, violate any applicable toxic effluent standard or prohibition, jeopardize the continued existence of endangered or threatened species or critical habitats, or violate any requirement for protection of a marine sanctuary; (3) show that the CCR unit or lateral expansion will not cause or contribute to significant degradation of wetlands; and (4) demonstrate that steps have been taken to attempt to achieve no net loss of wetlands.

In addition to these requirements, other federal laws may be applicable in siting a CCR unit in a wetland. These include: Sections 401, 402, and 404 of the CWA; the Rivers and Harbors Act of 1989; the National Environmental Policy Act; the Migratory Bird Conservation Act; the Fish and Wildlife Coordination Act; the Coastal Zone Management Act; the Wild and Scenic Rivers Act; and the National Historic Preservation Act. In addition, the use of a wetlands location for a CCR unit may require a permit from the U.S. Army Corps of Engineers. To the extent these are applicable, compliance with these RCRA criteria does not alleviate the need to comply with these other federal requirements, and the owner or operator of the facility remains responsible for ensuring compliance with all applicable federal and state requirements.

The rule adopts a regulatory presumption that a less damaging alternative to locating a disposal unit in a wetland exists, unless the owner or operator can demonstrate otherwise. Thus, when proposing to locate a new facility or lateral expansion in a wetland, owners and operators must be able to demonstrate that alternative sites are not available and that the impact to wetlands is unavoidable. If this presumption is not clearly rebutted, then the CCR unit may not be sited in a wetland location. Such an analysis necessarily includes a review of reasonable alternatives to locating or laterally expanding CCR units in wetlands. As part of the evaluation of reasonable (that is, available and feasible) alternatives the owner or operator must show, and a qualified professional engineer must verify, that operation or construction of the CCR unit will not: (1) Violate any applicable state water quality standards; (2) cause or contribute to the violation of any applicable toxic effluent standard or prohibition; (3) cause or contribute to violation of any requirement for the protection of a marine sanctuary; and jeopardize the continued existence of endangered or threatened species or critical habitats.

When evaluating the impacts of a CCR unit on a wetland, the owner or operator must ensure that the unit cannot cause or contribute to significant wetland degradation. Therefore, the owner or operator and the qualified professional engineer must: (1) Verify the integrity of the CCR unit, and its ability to protect ecological resources by addressing the erosion, stability, and migration potential of native wetland soils, and dredged and fill materials used to support the unit; (2) verify that the design and operation of the CCR unit minimizes impacts on fish, wildlife, and other aquatic resources and their habitat(s) from any release of coal combustion residuals; (3) evaluate the effects of catastrophic release of CCR to the wetland and the resulting impacts on the environment; and (4) verify that ecological resources in the wetland are sufficiently protected, including consideration of the volume and chemistry of the CCR managed in the unit; and any additional factors, as necessary.

When a wetland functions properly, it provides water quality protection, fish and wildlife habitat, natural floodwater storage, and reduction in the erosive potential of surface water. A degraded wetland is less able to effectively perform these functions. For this reason, wetland degradation is as big a problem as outright wetland loss, though often more difficult to identify and quantify. Any change in hydrology can significantly alter the soil chemistry and plant and animal communities. The common hydrologic alterations that can lead to significant degradation in wetland areas include: (1) Deposition of fill material, including CCR; (2) drainage for development; (3) dredging and stream channelization for development; (4) diking and damming to form ponds or impoundments; (5) diversion of CCR-bearing waters or other flows to or from wetlands; (6) addition of impervious surfaces in the watershed, thereby increasing water and CCR-bearing run-off into wetlands. These activities can mobilize CCR-bearing sediment; and once the sediment is discharged into the environment, toxic metals in CCR can become available to organisms within the wetland. Consequently, while the mere presence of one or more of these activities does not necessarily demonstrate that the CCR unit causes or contributes to significant degradation, the fact that they may do so means these activities need to be carefully evaluated.

In determining what constitutes "significant" degradation, it is important to understand that although wetlands are capable of absorbing pollutants from the surface water, there is a limit to their capacity to do so. For the purposes of this rule, the primary pollutants of concern are CCR-bearing sediment and toxic metals. Although the risk assessment did not assess the exposure and hazard to wetlands, these can originate from uncontrolled run-off from the facility, fugitive dust from uncovered CCR landfills and piles, and uncontrolled discharge from CCR units (landfills, waste piles, surface impoundments). A clear example of biologically significant degradation in wetlands is when these toxic metals accumulate in benthic and aquatic food chains as a result of uncontrolled runoff. Another is obrution (smothering) of benthic organisms from discharge(s) of CCR to surface water, thereby jeopardizing the continued existence of organisms or critical habitats within the wetland. EPA notes that there are other requirements established under this rule that can also be relevant in this context, as they have the potential to reduce the likelihood that facility operations will cause or contribute to significant wetland degradation. EPA anticipates that as the facility begins to implement all of the requirements under this rule, the facility will consider how modifications to facility operations to address one requirement can affect compliance with other requirements.

After consideration of these factors, if an existing CCR unit cannot meet all of the requirements in paragraphs (1)–(3) (*i.e.,* if it causes or contributes to significant degradation, or if no reasonable alternative to locating a new CCR unit in wetlands is available), the facility can comply with the location criterion by compensatory steps that must be taken to achieve no net loss of wetlands (as defined by acreage and function). Owners or operators must first take measures to avoid impacts to wetlands. If potential impacts cannot be avoided, all reasonable steps are to be taken to minimize such impacts to the extent feasible. Appropriate measures (for example, engineered containment systems to control discharge of leachate or surface water run-off to wetlands) will likely be site-specific and should be incorporated into the design and operation of the CCR unit. Any remaining unavoidable impacts must be offset, or compensated for through all appropriate and feasible compensatory mitigation actions. This compensatory

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mitigation may take the form of restoration (re-establishment or rehabilitation of a wetland), establishment (creation of a man-made wetland where one did not previously exist), enhancement (improving one or more wetland functions), and preservation (permanent protection of important wetlands through implementation of appropriate legal and physical mechanisms). The functions and values of a wetland will vary based on any number of site specific characteristics, including location, wetland type, hydrology, degradation, and whether it is natural or constructed to treat waste. Strictly limited to the application of the wetlands location requirements under this rule, any assessment of the nature and extent of mitigation required under the CCR rule shall consider these kinds of characteristics, including wetlands designed for the treatment of CCR. The Agency recognizes that the function and value of a particular man-made wetland constructed to perform a wastewater treatment function may present a unique situation that may affect both the determination of whether the wetland is significantly degraded, and the nature and extent of any required compensatory mitigation. This discussion refers only to the wetlands-related requirements of this rule and does not affect any requirements or obligations under the Federal Water Pollution Control Act (33 U.S.C. 1251, *et seq.*) and its implementing regulations.

Although EPA is not finalizing an outright ban on siting of existing or new CCR units in wetlands, the Agency continues to believe that discharges to wetlands of pollutants that can be reasonably avoided should be avoided. Therefore, the amount and quality of compensatory mitigation may not substitute for avoiding and minimizing impacts. For purposes of this rule, EPA assumes CCR units that are designed to avoid discharge of CCR into wetlands have less adverse impact to the aquatic environment than CCR units that ultimately discharge such residuals in wetlands.

4. Fault Areas

In § 257.62 of this rule, EPA is banning the location of new CCR landfills, existing and new CCR surface impoundments, and all new lateral expansions within 60 meters (200 feet) of a fault that has had displacement in Holocene time, unless the owner or operator demonstrates that an alternative setback distance of less than 60 meters (200 feet) will prevent damage to the structural integrity of the unit. For existing surface impoundments, the demonstration is required only if the unit is located closer than 60 meters (200 feet) to an active Holocene fault. If a demonstration cannot be made, the existing surface impoundment must close. These requirements have been adopted with only minor changes from the proposal, and will minimize the risks associated with CCR units located in fault areas.

Stresses produced during earthquake motion can cause serious damage to landfill integrity via seismically induced ground failure and associated rupture of liner systems and subsequent damage to leachate collection systems. Or if the unit is unlined, seismic motion could disrupt landfill caps and foundation soils that impede migration of percolating water. Potential damage to CCR units resulting from structures located across a fault include surface breakage, cracks and fissures between fill and confining slopes, slope failure via landslides, liquefaction-induced lateral spreading and settlement of the pile, disruption of surface water and drainage control systems, and rupture of leachate collection systems. In impoundments, for example, interior dike failure and leakage, and rupture of multilayer liner systems would also be of concern. Failure of the leachate collection system may prevent removal of generated leachate, allowing it to pond on the liner. If the liner system is ruptured, this may create a pathway for leachate to migrate into and contaminate the uppermost aquifer. In addition to the potential damage to leachate collection and liner systems, the integrity of the landfill slopes could also be impaired by fault rupture, potentially exposing coal combustion residuals to surface run-off.

The best protection is to avoid locating new CCR landfills and all CCR surface impoundments across faults and fault zones subject to displacement. For new units or lateral expansions there is no need to construct units in these areas. For existing surface impoundments, the Agency has been unable to find any way to retrofit or engineer the unit to be protective. A setback distance of 60 meters (200 feet) from the outermost damage zone of a Holocene fault will provide an adequate margin of safety to protect the facility from displacements due to surface faulting and any associated damage because 60 meters typically covers the zone of deformation where the ground may be bent or warped as a consequence of fault movement. By including this as a siting requirement for new units the risk of rupture of the unit, including any liner and leachate collection systems, due to surface faulting will be minimized.

Observations of engineered landfill response during earthquake motion come primarily from California where field data have been reported from MSWLFs (including some meeting the current part 258 standards) affected by strong shaking from six major nearby earthquakes. In these large magnitude events ($M \geq 6.7$), bedrock peak horizontal ground accelerations, an index of the intensity of earthquake motion, endured by the landfills were in excess of 0.3g. Engineered dry MSWLFs in California are reported to have performed well after strong earthquake motion (no documented incidence of an earthquake-induced release of contaminants harmful to human health or to the environment). Minor cracking of cover soils and breaking of vertical wells and headers were among the most common types of damage reported at MSWLFs subject to strong ground shaking. In the 1994 Northridge earthquake, only one landfill compliant with RCRA Part 258 standards experienced tears in a liner (a geomembrane liquid barrier): One tear 23 meters in length. However, there is little data on seismic stability and performance from industrial solid waste landfills with geosynthetic liners or units with water-saturated CCR waste. The Agency, therefore, remains concerned over the potential instability of engineered disposal units, and particularly CCR surface impoundments, under seismic loadings. Accordingly, EPA is prohibiting new CCR landfills, CCR surface impoundments, and any new extensions from sites located within an active fault zone, unless the owner or operator makes a demonstration, certified by a qualified professional engineer, that an alternative setback distance of less than 60 meters will prevent damage to the structural integrity of the unit.

EPA is clarifying its definition of fault to incorporate updated technical information.[56] Although a fault can be thought of as a simple planar surface across which there has been measurable displacement of one side relative to the other, field-based observations show fault architecture to often be complex. In the geologic literature faults developed in the upper crust are characterized as zones of brittle deformation composed of linked fault segments, with each segment composed of one or more subparallel, curved, or anastomosing fault cores nested within

[56] Sibson, R.H. 2003. Thickness of the Seismic Slip Zone. Bulletin of the Seismological Society of America, Vol. 93, No. 3, pp. 1169–1178.

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a damage zone. Some fault zones may contain broad deformational features such as pressure ridges and sags rather than clearly defined fault scarps or shear zones.[57] Fault cores are regions of high strain slip that have accommodated most of the displacement and are marked by mylonites, cataclastites, and gouge, whereas the damage zone is characterized by low strain structures mechanically related to the growth of the fault zone such as small faults, fractures, veins and folds. To avoid displacement that would damage unit integrity, it is best to restrict new CCR landfills and surface impoundments, and all new extensions, to locations no less than 60 meters from the outermost damage zone created by an active fault. Fault zones can range from one meter to several kilometers in width.

For purposes of this section, a fault is considered active if it has moved during Holocene time. Holocene time is defined as the geological epoch which began at the end of the Pleistocene, at 11,700 years BP (before present), and continues to the present. In the field, evidence for Holocene activity may be hard to obtain. Therefore, the Agency cautions that faults which show no evidence for Holocene activity may not necessarily be inactive.

To investigate active faults, EPA expects owners and operators of CCR units to follow standard engineering and geologic practices. Technical considerations include: (1) A geologic reconnaissance of the site to determine the location of active faults. Such a reconnaissance would include utilizing the seismic analysis maps and tools (Quaternary fault maps, earthquake probability maps) of the United States Geological Survey (USGS) Earthquake Hazards Program (*http://earthquake.usgs.gov/hazards/apps/*); and (2) a site fault characterization within 1000 meters of a site to determine whether it is within 60 meters of an active fault. Such characterizations would include subsurface exploration, including drilling or trenching, to locate any fault zones and evidence of faulting, trenching perpendicular to any faults or lineaments found within 60 meters of the site, and determination of the age of any displacements. Based on this information, the qualified professional engineer would prepare a report that delineates the location of any active (Holocene) fault, including any damage zones, and the associated 60 meter setback. To take advantage of an alternative setback distance of less than 60 meters, the owner or operator must make a demonstration, certified by a qualified professional engineer, that the CCR landfill, surface impoundment, or lateral expansion has a foundation or base capable of providing support for the structure, and capable of withstanding hydraulic pressure gradients to prevent failure due to settlement, compression, or uplift, and all effects of ground motions resulting from at least the maximum surface acceleration expected from a probable earthquake.

5. Seismic Impact Zones

In § 257.63, EPA is adopting the provisions applicable to seismic impact zones, as proposed. The rule prohibits new CCR landfills, existing and new CCR surface impoundments and all lateral extensions from being located in seismic impact zones unless the owner or operator makes a demonstration, certified by a qualified professional engineer, that all containment structures, including liners, leachate collection systems, and surface water control systems, are designed to resist the maximum horizontal acceleration in lithified earth material from a probable earthquake. A *Seismic impact zone* means an area having a 2% or greater probability that the maximum expected horizontal acceleration, expressed as a percentage of the earth's gravitational pull (g), will exceed 0.10 g in 50 years. Seismic zones, which represent areas of the United States with the greatest seismic risk, are mapped by the U.S. Geological Survey and readily available for all the U.S. (*http://earthquake.usgs.gov/hazards/apps/*).

*Maximum Horizontal Acceleration in lithified earth material* means the maximum expected horizontal acceleration at the ground surface as depicted on a seismic hazard map, with a 98% or greater probability that the acceleration will not be exceeded in 50 years, or the maximum expected horizontal acceleration based on a site-specific seismic risk assessment. This requirement translates to a 10% probability of exceeding the maximum horizontal acceleration in 250 years.

For units located in seismic impact zones, as part of any demonstration, owners and operators should include: (1) A determination of the expected peak ground acceleration from a maximum strength earthquake that could occur in the area; (2) a determination of the site-specific seismic hazards such as soil settlement; and (3) a facility design that is capable of withstanding the peak ground acceleration. Seismic designs broadly should include a response analysis to quantify the demands of earthquake motion on facility structures (*i.e.,* landfills, surface impoundments, liners, covers, leachate collection systems, surface water handling systems), liquefaction analyses of both waste and foundation soils to evaluate stability under seismic loading, and a slope stability and deformation analyses. Design modifications to accommodate seismic risks should include use of conservative design factors, use of ductile materials, built-in redundancy for critical system components, and other measures capable of mitigating the potential for seismic upset.[58]

Following trends in earthquake engineering, seismic design criteria for new CCR landfills, new CCR surface impoundment and all lateral expansions should be based on a "withstand without discharge" standard.[59] EPA interprets the performance standard in this criterion ("designed to resist the maximum horizontal acceleration in lithified earth material from a probable earthquake") to require any new CCR unit located in a seismic impact zone to be designed to withstand seismic motion from a credible earthquake without damage to the foundation or to the structures that control leachate, surface drainage, or erosion. In other words, the CCR unit must be able to withstand an expected earthquake without discharging waste or contaminants. The owner or operator must make a demonstration, certified by a qualified professional engineer, that the CCR unit has a foundation or base capable of providing support for the structure, and capable of withstanding hydraulic pressure gradients to prevent failure due to settlement, compression, or uplift and all effects of ground motions resulting from at least the maximum surface acceleration expected from a probable earthquake. In practice, the Agency recognizes that the CCR unit may sustain some limited damage during an earthquake, but ultimately, the CCR unit design must remain

[57] Bryant, W.A. and Hart, E.W., 2007. Fault-Rupture Zones in California. Special Publication 42 (Interim Revision), California Division of Mines and Geology, Sacramento, California.

[58] The *seismic location standard* requires a demonstration that a CCR disposal unit can withstand the stresses imposed by peak ground acceleration during earthquake motion. The *seismic factor of safety* is a unitless measure of strength calculated for fill material assuming earthquake conditions. It is the ratio of material shear strength relative to the magnitude of shear forces acting on the material. For a CCR disposal unit, the *seismic location demonstration* could be composed of numerous *factor of safety* calculations showing that the structural components of the unit have factors of safety greater than or equal to 1.00.

[59] Kavazanjian, E., 1999. Seismic Design of Solid Waste Containment Facilities. Proceedings of the Eight Canadian Conference on Earthquake Engineering Vancouver, BC, pp. 51–89.

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capable of preventing harmful release of CCR, leachate, and contaminants both during and after the seismic event.

6. Unstable Areas

EPA laid out its rationale for these requirements in the proposal at 75 FR 35201. No significant comments were received on either this rationale or the specific regulatory provisions. Consequently, EPA is adopting the regulatory text as proposed. Specifically, under § 257.64(a) new and existing CCR landfills, new and existing CCR surface impoundments and all lateral expansions are prohibited from sites classified as unstable areas unless the owner or operator makes a demonstration, certified by a qualified professional engineer, that engineering measures have been incorporated into the CCR unit's design to ensure that the structural components will not be disrupted. EPA considers a structural component to include any component used in the construction and operation of CCR landfill or CCR surface impoundment that is necessary to ensure the integrity of the unit and to ensure that the contents will not be released to the environment, including liners, leachate collection system, embankments, spillways, outlets, final covers, inflow design flood controls systems. Liners and leachate collection systems require a firm, secure foundation to maintain their integrity, and may be disrupted as a result of uneven settlement induced by hydrocompaction. Similarly, sudden differential movement resulting from CCR placement and the consequent exceedance of the weight-bearing strength of subsurface materials in unstable areas can destroy liners and damage the unit's structural integrity, resulting in catastrophic release of CCR. It is essential for the owner or operator of any CCR unit to extensively evaluate the adequacy of the subsurface foundation support for the structural components of the unit. Therefore, the Agency is making this demonstration mandatory for all CCR units; existing CCR units for which a demonstration cannot be made must be closed.

EPA has adopted the following definitions without material change from the proposal: *Unstable area* means a location that is susceptible to natural or human-induced events or forces capable of impairing the integrity of some or all of the structural components responsible for preventing releases from a CCR unit. Natural unstable areas include those areas that have poor soils for foundations, areas susceptible to mass movements, and karst terrains. *Structural components* mean liners, leachate collection systems, final covers, run-on/run-off systems, and any other component used in the construction and operation of a CCR unit. *Poor foundation conditions* means those areas where features exist which may result in inadequate foundation support for the structural components of a CCR unit. *Areas susceptible to mass movement* means those areas of influence (*i.e.,* areas characterized as having an active or substantial possibility of mass movement) where the movement of earth material at, beneath, or adjacent to the CCR unit, because of natural or man-induced events, results in the downslope transport of soil and rock material by means of gravitational influence. Areas of mass movement include, but are not limited to, landslides, avalanches, debris slides and flows, solifluction, block sliding, and rock fall. *Karst terrain* means an area where karst topography, with its characteristic erosional surface and subterranean features, is developed as the result of dissolution of limestone, dolomite, or other soluble rock. Characteristic physiographic features present in karst terrains include, but are not limited to, dolines (sinkholes), vertical shafts, sinking streams, caves, seeps, large springs, and blind valleys.

The owner or operator must consider at a minimum, the following factors when determining whether an area is unstable: (1) On-site or local soil conditions that may result in significant differential settling; (2) on-site or local geologic or geomorphologic features; and (3) on-site or local human-made features or events (both surface and subsurface). To evaluate subsurface conditions for purposes of § 257.64(c)(3), EPA considers it essential that the owner or operator conduct a geotechnical site investigation, certified by a qualified professional engineer, to identify any potential thick layers of soil that are soft and compressible (*e.g.,* loess, unconsolidated clays, wetland soils), which could cause a significant amount of post-construction differential settlement of foundation soils, adjacent embankments, and slopes unless improved. In addition, it is essential that the investigation identify on-site or local soil conditions that are conducive to downslope movement of soil, rock, and/or debris (alone or mixed with water) under the influence of gravity. Local topography, surface and subsurface soils, surface slope angles, surface drainage and run-off patterns, seepage patterns, rock mass orientations, joint patterns, fissures, and any other landscape factors that could influence downslope movement should be identified. Anthropogenic activities that could induce instability include mining, cut and fill activities during construction, excessive drawdown of groundwater, which may cause excessive settlement or bearing capacity failure of foundation soils, and use of an old landfill as the foundation for a new landfill without verification of complete settlement of the underlying wastes.

In designing a new CCR unit located in an unstable area, recognized and generally accepted good engineering practices dictate that a stability assessment should be conducted to prevent a destabilizing event from damaging the structural integrity of the component systems. For CCR units this involves three components: (1) An evaluation of subsurface conditions, (2) an analysis of slope stability, and (3) an examination of related design needs. In addition to explaining site constraints, identifying any soft soils, and recommending any appropriate ground improvement techniques, the assessment report should include a description of: The site, site geology; and investigative methodology; the results from all site investigations including subsurface exploration, field and laboratory tests, and test results; the subsurface profile, recommended foundation types, depths, and bearing capacities; the water content, grain-size distribution, shear strength, plasticity, and liquefaction potential of foundation soils and subsoils; and other foundation consolidation and settlement issues relevant to site development.

In addition to assessing the ability of soils and rocks to serve as a foundation, it is essential that the report also include a stability assessment of excavated sideslopes, aboveground embankments or dikes, and retaining structures. The slope stability analyses are performed as part of an evaluation of the design configuration under all potential hydraulic and loading conditions, including conditions that may exist during construction of a lateral or vertical expansion. As part of any demonstration, owners and operators should make an assessment, certified by a qualified professional engineer, that finalized site embankments and slopes are able to maintain a stable condition. In addition to evaluating the potential for post-construction differential settlement, the stability assessment should also consider seepage-induced saturation and softening of soils, particularly at CCR surface impoundments and CCR landfill sites that manage effluent.

Engineering considerations for CCR landfills and lateral expansions located in unstable areas are expected to be

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similar to those for MSWLFs, which can be found in EPA's 1993 Technical Manual on Solid Waste Disposal Facility Criteria (EPA530–R–93–017). For surface impoundments the relevant design criteria are found in the Agency's 1991 Technical Resource Document on Design, Construction and Operation of Hazardous and Non-Hazardous Waste Surface Impoundments (EPA/530/SW–91/054). Any stability assessment should consider the following: (1) The adequacy of the subsurface exploration program; (2) the liquefaction potential of the embankment, slopes and foundation soils; (3) the expected behavior of the embankment slopes, and foundation soils when they are subjected to seismic activity; (4) the potential for seepage-induced failure; and (5) the potential for differential settlement.

For facilities in areas of karst, to support the demonstration required under the regulations, the owner or operator would need to evaluate the subsurface conditions to ensure that the unit is located away from the influence of potential sinkholes. For areas where the solution-weathered limestone is close to the surface (*e.g.,* Florida) recognized and generally accepted good engineering practices dictate that there must be no conduits beneath the CCR unit that allow piping of groundwater into the karst aquifer, or shallow caves that could cause sudden collapse of the unit foundation. Where unconsolidated sediments cover underlying limestone, piping is commonly marked by paleosinks where sands and clays from the overburden have filled solution cavities in the underlying limestone.[60] Local hydraulic gradients in paleosinks typically point downward. EPA generally expects the potential for sinkhole development to be minimal at locations in karst areas where there are no paleosinks, or historical record of sinkhole development, and where there are no local hydraulic gradients that point downward.

In making a demonstration, it is important for owners and operators of CCR landfills and surface impoundments in karst areas to adequately characterize subsurface conditions. Karst hydrogeology is complex, since contaminant flows can occur along paths and networks that are discreet and tortuous, and groundwater monitoring wells must be capable of detecting any contaminants released from the CCR unit into the karst aquifer. Therefore, the owner or operator will need to ensure, with verification by a qualified professional engineer, that monitoring wells installed in accordance with § 257.91 will intercept these pathways. Verification will usually necessitate the use of tracers to track groundwater flow towards offsite seeps or springs from the uppermost aquifer beneath the facility.

Any engineered solution employed to mitigate weak ground strength in karst areas must be able to prevent the kind of foundation collapse and settlement that could lead to sudden release to the environment of CCR with its toxic constituents and associated leachate. Solution cavities present at the site should be filled with grout or other suitable stiff material to avoid further crumbling and erosion. Where necessary, CCR unit foundations could be reinforced with engineered ground supports such as concrete footings that bridge voids. Larger caverns could be filled with concrete to underpin the CCR unit foundation by transferring load to the cavern floor. However, such engineered solutions are complex and costly, and the best protection is not to site CCR landfills and surface impoundments in karst areas. Nevertheless, this rule does not ban the location of CCR landfills, surface impoundments, or lateral extensions in karst areas.

7. Closure of Existing CCR Landfills and Existing CCR Surface Impoundments

The final provisions of § 257.60 require owners or operators of an existing CCR surface impoundment to demonstrate that the unit meets the minimum requirements for placement above the uppermost aquifer (*i.e.,* constructed with a base located no less than 1.52 meters (five feet) above the upper limit of the uppermost aquifer) no later than 42 months after the date of publication of this rule in the **Federal Register**.

Owners and operators of existing CCR surface impoundments subject to §§ 257.61–257.64 of this rule and existing CCR landfills subject to § 257.64, must complete demonstrations by the date corresponding to 42 months from publication of this rule. The Agency is setting the compliance deadline at 42 months to allow owners and operators time to complete the requisite studies (*e.g.,* to adequately characterize seasonal variations in the elevation of the top of the uppermost aquifer) and to complete any engineering measures necessary to allow the CCR unit to meet the performance standards. If closure is warranted, it must be initiated no later than 48 months from publication of this rule. Closure and post-closure care must be done in accordance with §§ 257.100–103; which allow certain regulatory flexibilities provided specific conditions are met.

*D. Design Criteria—Liner Design*

EPA proposed that existing CCR landfills without a composite liner could continue to operate and receive CCR without violating the open dumping prohibition. Conversely, EPA proposed that existing CCR surface impoundments would be required to retrofit with a composite liner system, as defined in the proposed rule, within five years of the effective date of the rule or to close. EPA also proposed that all new CCR units must be constructed with a composite liner and leachate collection and removal system.

In the proposal, EPA defined a *composite liner* to mean a liner system consisting of two components; the upper component consisting of a minimum 30-mil flexible membrane liner (FML), and the lower component consisting of at least a two-foot layer of compacted soil with a hydraulic conductivity of no more than $1 \times 10^{-7}$ cm/sec.[61] FML components consisting of high density polyethylene (HDPE) were required to be at least 60-mil thick; and the FML component was required to be installed in direct and uniform contact with the compacted soil component.

EPA solicited comment on a number of issues, including: (1) Whether EPA should allow facilities to use an alternative design for new CCR units; (2) whether clay liners designed to meet a $1 \times 10^{-7}$ cm/sec hydraulic conductivity might perform differently in practice than modeled in the risk assessment, including a request for specific data on the hydraulic conductivity of clay liners associated with CCR units; and (3) whether the effectiveness of such additives as organosilanes, would allow the use of these additives in lieu of composite liners. (See 75 FR 35203 and 35222.)[62] With respect to the last two issues, the Agency received little comment. However, in response to the use of alternative liner designs in lieu of a composite liner (as defined in the rule), significant comment was received. Commenters advocated for a number of alternative composite liner designs, with a majority recommending that a

[60] For examples, see Garlanger, J.E., Foundation Design in Florida Karst. Online presentation by Ardaman & Associates. *http://www.ardaman.com/foundation_design.htm.*

[61] The definition of *hydraulic conductivity* is being promulgated as proposed, and will mean the rate at which water can move through a permeable medium (*i.e.,* the coefficient of permeability).

[62] The terms compacted soil and compacted clay are used interchangeably, *i.e.,* when referring to a compacted soil liner this is the same as referring to a compacted clay liner (CCL).

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geosynthetic clay liner (GCL) be allowed as an alternative to the lower component of the composite liner. Other commenters stated that GCLs alone should be allowed as an alternative to the proposed composite liner. Still others argued that alternative liner designs, such as an FML/FML [63] provided a level of performance similar to the proposed composite liner system and should be allowed. Conversely, there were also comments opposing the use of any alternative liners, claiming that alternatives have not been proven to be effective.

EPA also received significant comment on the actual design of the composite liner system proposed by the Agency as it pertained to CCR surface impoundments (see 75 FR 35202–35203).[64] Commenters argued that the proposed requirement for a leachate collection and removal system in a CCR surface impoundment was illogical since it would have to be constructed between the lower component (two feet of compacted soil) and upper component (flexible membrane liner) and the proposed rule specifically states that the flexible membrane liner component must be installed in direct and uniform contact with the compacted soil component. Commenters reasoned that the inclusion of a leachate collection and removal system between the upper and lower components precluded direct and uniform contact between the two components and that placing a leachate collection and removal system between the lower and upper components of a composite liner would compromise the integrity of the composite liner. With regard to this last point, the Agency has reviewed the requirements for a proposed composite liner system as it would pertain to CCR surface impoundments and agrees that the leachate collection and removal system requirements proposed for CCR surface impoundments would be counterproductive; EPA proposed this requirement in error. The integrity of the composite liner system is indeed dependent upon the direct and uniform contact of the upper GM component with the lower soil component. The proposed requirement for CCR surface impoundments to construct a leachate collection system between the FML and soil components would prevent the direct and uniform contact of the upper and lower components and, therefore, compromise the integrity of the composite liner. For this reason, EPA is not requiring a leachate collection and removal system for new surface impoundments or any lateral expansion of a CCR surface impoundment.

While EPA agrees with those commenters arguing that new CCR units should only be installed with a composite liner system of some kind, the Agency has concluded that not all alternative designs for a composite liner system should necessarily be rejected as insufficiently protective. Many commenters provided strong and compelling evidence that the specific composite liner system described in the proposed rule was not always feasible or necessary to protect groundwater resources and that alternate composite liner designs could be equally protective, and may be a necessity in many areas of the country where soil with the appropriate hydraulic conductivity may not be available (*e.g.*, Alaska).[65]

In re-evaluating the proposed requirement for a composite liner system, EPA was influenced by a number of factors.[66] First, the data provided by commenters showing the performance of a GM/GCL design. Second, EPA's own studies showing that a GM/GCL liner can be constructed to achieve hydraulic efficiencies in the range of 99 to 99.9% which meets or exceeds the hydraulic performance of a GM/compacted clay liner (CCL) design.[67] In addition, these high efficiencies demonstrate that the GCL component of a GM/GCL composite liner is at least as effective in impeding leakage through holes in the GM component of the composite liner system as a CCL with a hydraulic conductivity no more than $1 \times 10^{-7}$ cm/sec.[68] In fact, EPA has developed guidance for the selection and installation of various types of liners including a GM/GCL.[69] And third, EPA was influenced by the many comments arguing that a "one-size-fits all" approach to liner design stifles design innovation and regulatory flexibility in addressing site specific factors such as geologic or climatic conditions. These commenters reasoned that if EPA established some type of performance standard for composite liners, it would mitigate the negative impacts of a "one-size fits all" regulatory framework.

1. Development of Composite Liner Design Criteria

In this final rule EPA is requiring all new CCR units to be designed and constructed with a composite liner as specified in § 257.70. EPA is also providing the owner or operator with an option to install an alternative composite liner provided it meets the required performance standard and it is certified by a qualified professional engineer. EPA has concluded, consistent with many of the comments received and its own analysis, that an alternative composite liner for new CCR units is warranted if it can be shown to be equivalent to the performance of a composite liner and affords the same protections to groundwater resources as a composite liner. The Agency is promulgating this alternative option to provide flexibility in designing and constructing a protective composite liner system that addresses site specific conditions and situations. The Agency acknowledges that it was overly prescriptive by requiring one particular type of liner rather than relying on a performance standard to define the lower component of the composite liner. The overwhelming amount of data supporting the effectiveness of a GC/GCL liner has convinced the Agency that the final rule should allow for some flexibility in composite liner designs. As such, the Agency is allowing new CCR units to be designed and constructed

[63] Current terminology favors the use of geomembrane liner or GM when referring to flexible membrane liners or FMLs. Hereafter in the preamble, except when referring to specific comments or the proposed rule, and in the final rule, the Agency will use the term geomembrane liner or GM in place of flexible membrane liner or FML.

[64] See proposed § 257.71 which states that an existing CCR surface impoundment shall be constructed with a composite liner and a leachate collection system between the upper and lower components of the composite liner; where a composite liner means a system consisting of two components; the upper component consisting of a minimum 30-mil flexible membrane liner (FML) and a lower component consisting of at least a two-foot layer of compacted soil with a hydraulic conductivity of no more than $1 \times 10^{-7}$ cm/sec. The FML component would be required to be installed in direct and uniform contact with the compacted soil component (see 75 FR 35243).

[65] See for example comments from the states of Alaska (EPA–HQ–RCRA–2009–0640–06409); Florida (EPA–HQ–RCRA–2009–0640–06846); and North Carolina (EPA–HQ–RCRA–2009–0640–09282) available at *www.regulations.gov.*

[66] Geomembranes (GMs), which are flexible membrane liners (FMLs), are thin materials manufactured from polymers and reinforced with woven fabric or fibers which are used as hydraulic barriers. Resins used to manufacture geomembrane liners typically include high density polyethylene (HDPE), linear low density polyethylene (LLDPE), low density linear polyethlene (LDLPE), very low density polyethylene (VLDPE) and polyvinyl chloride (PVC). Geomembranes manufactured using HDPE are the least flexible of the geomembranes.

[67] USEPA, "Assessment and Recommendations for Improving the Performance of Waste Containment Systems," EPA 600/R–02/029, December 2002. *http://nepis.epa.gov/Adobe/PDF/P1001O83.pdf.*

[68] USEPA, "Assessment and Recommendations for Improving the Performance of Waste Containment Systems," EPA 600/R–02/029, December 2002.

[69] USEPA, "Guide for Industrial Waste Management," Chapter 7 (*http://www.epa.gov/osw/nonhaz/industrial/guide/pdf/chap7b.pdf*).

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with an alternative composite liner, as described below, provided the lower component of the composite liner meets a specified performance standard that ensures it functions in a manner equivalent to the composite liner system defined in the rule.

Composite liner systems installed in either a CCR landfill or CCR surface impoundment provide an effective hydraulic barrier by combining the complementary properties of the two different liner components. The geomembrane provides a highly impermeable layer that can maximize leachate collection and removal in a CCR landfill or minimize infiltration of leachate in a CCR surface impoundment, while the soil component (*e.g.,* CCL) serves as a backup in the event of any leakage/infiltration from the geomembrane occurs. Data indicate that alternatives to the lower component of the composite liner system (*e.g.,* GCLs) are available and can perform at a level equivalent to a compacted soil liner, based on a comparison of their flow rates with two feet of compacted soil with a hydraulic conductivity of no more than $1 \times 10^{-7}$ cm/sec.

2. Liner Designs That Would Not Meet the Requirements of a Composite Liner or Alternative Liner

Contrary to the arguments made by several commenters, EPA has concluded that a composite liner consisting of two 30-mil GMs (GM/GM) will not provide an equivalent degree of protection as a composite liner consisting of a GM and two feet of compacted soil, or an alternative composite liner such as a GM/GCL. While GMs have the advantages of extremely low rates of water permeation, the disadvantages of a composite liner consisting of two GMs include leakage through occasional GM imperfections and punctures, potential for slippage along the interface between the GMs, and GM embrittlement over time. Furthermore, a critical component of a composite liner is the compacted soil or GCL component beneath the GM layer that will impede the flow of liquid that may leak through a hole or defect in the GM. This added protection cannot be achieved using two GMs for the composite liner. Additionally, the potential exists for liquid transport through the GMs through holes caused by punctures, tears, flawed seams, etc. If a puncture occurs, the puncture could compromise both GMs and create a conduit for liquid flow to underlying permeable soil. Moreover, a liner system consisting of two GMs in contact with each other poses the risk of creating a slip plane that may compromise the stability of the disposal unit (although EPA acknowledges that using textured GMs would reduce or eliminate this particular risk). These data are documented in EPA research.[70]

Consistent with the previous determination, EPA has also determined that the double liner system set forth in Florida regulations (see Florida Rules 62–701.400(3)(c), F.A.C) also does not meet the level of performance achieved by EPA's composite liner system or the alternative liner system. While this double liner system provides the advantage of a leak detection system between the two GMLs, the lower composite liner, consisting of a 60-mil HDPE over six inches of soil with a saturated hydraulic conductivity of less than or equal to $1 \times 10^{-5}$ cm/sec, is not equivalent to a GM over two feet of compacted soil with a hydraulic conductivity of less than or equal to $1 \times 10^{-7}$ cm/sec. To be hydraulically equivalent, soil with a hydraulic conductivity of $1 \times 10^{-5}$ cm/sec would need to be on the order of 100 times thicker than soil with a hydraulic conductivity of less than or equal to $1 \times 10^{-7}$ cm/sec. Similarly, a lower composite liner consisting of a 60-mil HDPE over a GCL with a hydraulic conductivity not greater than $1 \times 10^{-7}$ cm/sec would require a GCL thickness of 24 inches to be equivalent to a GM over two feet of compacted soil with a hydraulic conductivity of less than or equal to $1 \times 10^{-7}$ cm/sec.

EPA has also examined the performance of GCLs approved for use as alternatives to composite liners in MSWLFs.[71] The EPA report titled "Assessment and Recommendations for Improving the Performance of Waste Containment Systems," [72] concluded that if a CCL or GCL is used alone, liquid migration can occur over the entire area of the liner that is subject to a hydraulic head. The report also concluded that in a composite liner, leakage will only occur at the location of the geomembrane penetration (*e.g.,* hole, tear), and will be much slower than flow through an orifice due to the hydraulic impedance provided by the CCL or GCL alone. The report also evaluated, among other characteristics, the hydraulic efficiencies of a GM/GCL composite liner system for 28 cells at seven landfills. Liner hydraulic efficiencies were reported between 97% and 100%. However, potential stability problems were reported with GCLs constructed on slopes greater than 10 H:1 V (5.7°), and GCLs may not be appropriate for the disposal of liquid wastes or sludges. The Agency is also concerned that GCLs, being much thinner than the two feet of compacted soil required for composite liners, may allow for the flow of liquids through the GCL at a faster rate than through two feet of compacted soil. Taking all of this information into account, the Agency remains unconvinced that a GCL alone is a viable alternative to a composite liner.

3. Design Requirements

a. Existing CCR Landfills

As proposed, the final rule allows existing CCR landfills as defined in § 257.54, to continue to operate without retrofitting with a composite liner and leachate collection and removal system. As previously discussed, given the volume of the material currently managed in CCR landfills, the potential for disruption in CCR disposal capacity if existing CCR landfills were required to retrofit would be significant. Significant disruptions in the state-wide solid waste management (and possibly power generation) are associated with significant risks to public health and the environment in their own right. EPA has concluded that these risks are greater than the risks associated with allowing unlined CCR landfills to continue to operate. Further, existing CCR landfills will be required to comply with the extensive groundwater monitoring and corrective action requirements, among others, to ensure that any groundwater releases from the CCR unit are identified and promptly remediated, which will significantly mitigate the risks from these existing units. By themselves, the risk assessment results and the risk migration from the other regulatory requirements in this rule would not support a decision to allow these CCR units to continue to operate on a national basis. But when the risks associated with the level of disruption EPA estimates to be possible from requiring existing CCR landfills to retrofit are also included, the totality of the evidence supports a determination that allowing these units to continue operating meets the section 4004(a) standard.

[70] "Assessment and Recommendations for Improving the Performance of Waste Containment Systems."

[71] "Geosynthetic Clay Liners Used in Municipal Solid Waste Landfills," *http://www.epa.gov/wastes/nonhaz/municipal/landfill/geosyn.pdf*; "Geosynthetic Clay Liners in Waste Containment," *http://www.epa.gov/superfund/remedytech/tsp/download/2001_meet/prez/carson.pdf*; and "Assessment and Recommendations for Improving the Performance of Waste Containment Systems," *http://nepis.epa.gov/Adobe/PDF/P1001O83.pdf*.

[72] "Assessment and Recommendations for Improving the Performance of Waste Containment Systems."

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b. Existing CCR Surface Impoundments

In a departure from the proposed rule and after considerable evaluation and analysis, the Agency is finalizing a provision to allow all existing CCR surface impoundments to remain in operation provided certain conditions are met.[73] Owners or operators of existing CCR surface impoundments are required, within one year of the effective date of the rule, to document, certified by a qualified professional engineer, whether the unit is constructed with any one of the three liner types: (1) A liner consisting of a minimum of two feet of compacted soil with a hydraulic conductivity of no more than $1 \times 10^{-7}$ cm/sec; (2) a composite liner that meets the requirements of § 257.70(b); or (3) an alternative liner that meets the requirements of § 257.70(c). In some instances, owners or operators may have information readily available to determine if an existing CCR surface impoundment is constructed with one of the three liner types listed above. On the other hand, this information may not be readily available and may require an owner or operator to conduct an engineering evaluation to determine if the unit was constructed with any of the three liner type. Factors such as the availability of engineering personnel and weather may impede the engineering evaluation. Therefore, EPA believes that 12 months from the effective date, or 18 months from publication of the rule, is a reasonable amount of time to make the determination of whether the existing CCR surface impoundment was constructed with one of the three liner types described above. Existing surface impoundments with liners that meet the criteria established for any of the three specified liner types are considered to be an "existing lined CCR surface impoundments." These existing lined surface impoundments can continue to operate until the owner or operator decides to initiate closure, provided the unit does not meet other requirements of the rule that independently mandate closure of the unit (*e.g.,* location criteria (§§ 257.60–257.64) or structural integrity factors of safety (§ 257.73)). Existing unlined CCR surface impoundments must also cease receiving CCR and initiate closure if an owner or operator determines, at any point in time, as part of its groundwater monitoring program that the concentrations of one or more constituents listed in appendix IV to part 257 are detected at a statistically significant level above the groundwater protection standard established for that unit. EPA agrees with the many commenters who argued that existing unlined CCR surface impoundments should not be required to close prematurely if they are operating as designed and are complying with all of the requirements of the rule, including all groundwater protection standards. Taking into account the additional protections required under this rule (*e.g.,* location restrictions, groundwater monitoring, corrective action, structural integrity criteria, inspections and fugitive dust controls), the Agency has concluded that the risks posed by unlined CCR surface impoundments that are not "leaking" (*i.e.,* exceeding any groundwater protection standard) are not sufficient to warrant requiring these units to close. However, once a groundwater protection standard is exceeded (*i.e.,* the unit is leaking), without any type of liner system in place, leachate will flow through the unit and into the environment unrestrained and the only corrective action strategy that EPA can determine will be effective at all sites nation-wide requires as its foundation the closure of the unit.

EPA acknowledges that it may be possible at certain sites to engineer an alternative to closure of the unit that would adequately control the source of the contamination and would otherwise protect human health and the environment. However, the efficacy of those engineering solutions will necessarily be determined by individual site conditions. As previously discussed, the regulatory structure under which this rule is issued effectively limits the Agency's ability to develop the type of requirements that can be individually tailored to accommodate particular site conditions. Under sections 1008(a) and 4004(a), EPA must establish national criteria that will operate effectively in the absence of any guaranteed regulatory oversight (*i.e.,* a permitting program), to achieve the statutory standard of "no reasonable probability of adverse effects on health or the environment" at all sites subject to the standards. EPA was unable to develop a performance standard that would allow for alternatives to closure, but would also be sufficiently objective and precise to minimize the potential for abuse. There are too many factors that determine whether a particular engineering solution will meet the section 4004(a) standard at a particular site. And the risks of these units are simply too high.

Conversely, existing lined surface impoundments that exceed their groundwater protection standard are in a better position to manage the leak because it is usually caused by some localized or specific defect in the liner system that can more readily be identified and corrected. Consequently, this rule is not requiring existing lined CCR surface impoundment to close if an exceedance of a groundwater protection standard is detected; rather the Agency is affording the owner or operator with the opportunity to rely on corrective action measures to bring the risks back to acceptable levels (*i.e.,* control the source of the release and remediate the contamination), without mandating closure of the unit.

c. New CCR Landfills and New CCR Surface Impoundments and All Lateral Expansions

Both the CCR damage case history and the risk assessment clearly show the need for and the effectiveness of appropriate liners in reducing the potential for groundwater contamination at CCR landfills and CCR surface impoundments. Accordingly, EPA is finalizing liner and leachate collection and removal system requirements for new CCR landfills and all lateral expansions of these units. Similarly, EPA is finalizing liner requirements for new CCR surface impoundments and all lateral expansions of these units.

Specifically, EPA is requiring new CCR landfills, new CCR surface impoundments, and all lateral expansions be constructed with a composite liner (see § 257.70). The composite liner must consist of two components; an upper component consisting of a minimum 30-mil geomembrane liner (GM), and a lower component consisting of at least a two-foot layer of compacted soil with a hydraulic conductivity of no more than $1 \times 10^{-7}$ centimeters per second (cm/sec). GM components consisting of high density polyethylene (HDPE) must be at least 60-mil thick and the GM or upper liner component must be installed in direct and uniform contact with the compacted soil or lower liner component

New CCR landfills or lateral expansions of these units are also required to be constructed with a leachate collection and removal system designed to maintain less than a 30-centimeter depth of leachate over the composite liner. A leachate collection and removal system is not required for new CCR surface impoundments

[73] Existing CCR surface impoundments will not be required, as was proposed, to retrofit to a composite liner or close within five years of the effective date of the rule (see 57 FR 35202).

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because, as previously discussed, a leachate collection system installed between a single composite liner system is not practicable and would compromise the integrity of the composite liner system.

In addition, in response to comments on the proposed rule, EPA is allowing alternatives to the lower component of the composite liner system provided the flow rate through the lower component is no greater than the flow rate through two feet of compacted soil with a hydraulic conductivity of $1 \times 10^{-7}$ cm/sec. The lower component must also be a recognized liner material; *e.g.,* soil, clay, or GCL. Alternative composite liners using compacted soil or clay as the lower component must be constructed with the upper component in intimate contact with the lower component; *i.e.,* the geomembrane must be installed to ensure good and uniform contact with the lower component. The hydraulic conductivity for the two feet of compacted soil used in the flow rate comparison must be no greater than $1 \times 10^{-7}$ cm/sec. The hydraulic conductivity of the lower component must be determined using recognized and generally accepted engineering methods, for example, ASTM D5084–10, "Standard Test Methods for Measurement of Hydraulic Conductivity of Saturated Porous Materials Using a Flexible Wall Permeameter," ASTM International, West Conshohocken, PA, 2012, DOI: 10.1520/D5084–10, *www.astm.org* for compacted soils or clays, or ASTM Standard D6766–12, "Standard Test Method for Evaluation of Hydraulic Properties of Geosynthetic Clay Liners Permeated with Potentially Incompatible Aqueous Solutions," ASTM International, West Conshohocken, PA, 2012, DOI: 10.1520/D6766–12, *www.astm.org* for GCLs. The flow rate comparison for the lower component must be made using Darcy's Law for gravity flow through porous media, which is an empirical law which states that the velocity of flow through porous media is directly proportional to the hydraulic gradient. The use of Darcy's Law to calculate fluid flow through porous media is a well-established and generally accepted engineering methodology, and is the foundation for EPA's Composite Model for Leachate Migration with Transformation Products (EPACMTP) and is generally recognized to evaluate steady state flow of liquids through soils and GCLs.[74] EPACMTP is a subsurface fate and transport model EPA uses to simulate the impact of the release of constituents present in waste that is managed in land disposal units. Accordingly, the flow rate comparison for the lower component of alternative composite liner must be made using the following equation which is derived from Darcy's Law.

$$\frac{Q}{A} = q = k\left(\frac{h}{t} + 1\right)$$

where:

Q = flow rate,
A = surface area of the liner,
q = flow rate per unit area,
k = hydraulic conductivity of the liner,
h = hydraulic head above the liner, and
t = thickness of the liner.

A qualified professional engineer must certify that the design and construction of either the composite liner or the alternative composite liner meets the requirements of §§ 257.70(b) or (c).

EPA has also supplemented the composite liner criteria for landfills with performance standards that provide more precise direction to the professional engineer regarding the "recognized and generally accepted good engineering practices" that need to be used in the design and construction of composite liner systems to ensure that the liner system will continue to perform as designed. These criteria, which have been codified at §§ 257.70(b) and 257.70(c), have been adopted in response to comments requesting that EPA provide the professional engineers that will be required to certify that CCR units meet the requirements of the rule, with more precise and objective criteria. These criteria reflect the engineering specifications necessary to prevent liner failures resulting from improper design and construction and to ensure that the liner will continue to perform correctly. These provisions will ensure not only that the liner is properly designed and constructed, but also that the system will continue to safely perform throughout the landfill's active life and through post closure care. The criteria have been adopted from the technical provisions proposed under the subtitle C provisions for CCR landfills, and are consistent with design requirements set forth for hazardous waste landfills regulated under part 265 of RCRA, as well as existing guidance and recognized good engineering practices for the design and construction of MSWLFs.[75]

Specifically, the Agency is modifying the composite and alternative liner design requirements by requiring the composite or alternative liner to be chemically compatible with the CCR and of adequate strength and thickness to prevent failure. The liner system must also provide appropriate shear strength between the two components to prevent sliding of the upper component. In addition, the Agency is requiring that liners be placed on an adequate foundation and installed to cover all areas that might come into contact with the CCR.

For new CCR landfills, which are required to have a leachate collection and removal system designed and operated to maintain less than a 30 centimeter depth of leachate, the Agency is also requiring, that the leachate collection and removal system be constructed of sufficient strength and thickness to prevent collapse from the pressure of the CCR and to minimize clogging during the active life and post closure care period.[76]

4. Vertical Expansions of New and Existing CCR Landfills and All Lateral Expansions

In the proposed rule, EPA stated that CCR landfills could vertically expand without retrofitting, in order to alleviate concerns with regard to CCR disposal capacity in the short term. In the few comments to the proposed rule which mentioned vertical expansions of landfills, commenters requested that the Agency clarify the design standards that vertical expansions would have to meet. Information collected to date, which is included in the docket supporting the final rule, leads the Agency to conclude there are no issues unique to vertical expansions of CCR landfills that warrant modifications to the technical standards

[74] See for example EPA's Composite Model for Leachate Migration with Transformation Products (EPACMTP) at *http://www.epa.gov/epawaste/nonhaz/industrial/tools/cmtp/*, "Assessment and Recommendations for Improving the Performance of Waste Containment Systems." Giroud, J.P., Badu-Tweneboah, K. and Soderman, K.L., 1997, "Comparison of Leachate Flow Through Compacted Clay Liners and Geosynthetic Clay Liners in Landfill Liner Systems," Geosynthetics International, Vol. 4, Nos. 3–4, pp. 391–431 (*http://www.geosyntheticssociety.org/Resources/Archive/GI/src/V4I34/GI-V4-N3&4-Paper7.pdf*), and "Design Considerations for Geosynthetic Clay Liners (GCLs) in Various Applications," Geosynthetic Research Institute, January 9, 2013 (*http://www.geosynthetic-institute.org/grispecs/gcl5.pdf*).

[75] "Technical Guidance Document: Quality Assurance and Quality Control for Waste Containment Systems." U.S. Environmental Protection Agency. Risk Reduction Engineering Laboratory, Office of Research and Development, Cincinnati, OH 45268. EPA/600/R–93/182. September 1993.

[76] Hardin, PE, Christopher D, and Perotta, PE Nick L. "Operations and Maintenance Guidelines for Coal Ash Landfills—Coal Ash Landfill are NOT the Same as Subtitle D Solid Waste Landfills". Presented at the 2011 World of Coal Ash Conference; May 9–12, 2011 in Denver, Colorado. *http://www.flyash.info/2011/127-Hardin-2011.pdf.*

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being promulgated in this rule. Therefore, vertical expansions of existing CCR landfills are not subject to the provisions governing new units, but are subject to all applicable requirements for existing CCR landfills. To be clear however, while the location requirements relating to the placement above the water table, wetlands, fault areas, and seismic impact zones do not apply to existing CCR landfills, all of these restrictions apply to lateral expansions of existing CCR units, as well as new CCR units. Consequently, under this rule, owners or operators of existing CCR landfills can continue to vertically expand their existing facilities in these locations, but must comply with the provisions governing new units if they wish to laterally expand.

5. Construction of New CCR Landfills or Any Lateral Expansion Over an Existing CCR Unit

On August 2, 2013, EPA published a NODA that among other things, solicited comment regarding a particular type of CCR management unit described by some commenters in the proposed rule as "overfills" (see 78 FR 46940). Overfills are CCR landfills constructed over a closed CCR surface impoundment. As discussed in the NODA, in developing the proposed rule, EPA was not aware that CCR was managed in this fashion and so did not either evaluate this specific management scenario or propose technical requirements specifically tailored to this type of unit. Under the proposed rule, these types of units would need to comply with both the requirements applicable to the closure of surface impoundments or landfills, and with all of the technical requirements applicable to new landfills. Information collected since the proposal confirmed that the practice of constructing overfills for the disposal of CCR is conducted with some regularity, and raised questions as to whether overfills would be effectively regulated under the proposed technical requirements of the rule. In the NODA, to aid in the development of final technical requirements, EPA solicited data and information that directly addressed existing engineering guidelines or practices applicable to this units, as well as any regulatory requirements governing the siting, design, construction, and long-term protectiveness of these units for the disposal of CCR.

The Agency received numerous comments on the NODA. The majority of commenters agreed that overfills are commonly employed to allow continuing use of CCR disposal sites and to avoid the need to develop CCR management units at other sites. Some commenters added that: (1) The engineering design of an overfill can increase the stability of the underlying surface impoundment or landfill; (2) the use of an overfill facility reduces the need for new infrastructure construction; and (3) an overfill avoids having to transport CCR significant distances for off-site disposal.

Other commenters mentioned that several states had experience with overfills and have applied requirements such as liner systems, monitoring wells, and stormwater modeling on a case-by-case basis using best engineering practices. They added that overfills pose unique construction and operational issues depending on the site and the characteristics of the underlying unit, and that the construction of these units will therefore vary to account for these conditions. Commenters identified several issues requiring additional attention during design and construction of overfills including seismic and static liquefaction, settlement, foundation improvement, partial overfills, groundwater upwelling, groundwater monitoring, and wastewater infrastructure.

Upon review of these comments and further evaluation, the Agency has concluded that while there may be technical issues relating to the design, construction, and maintenance of overfills, the technical standards for CCR landfills are sufficiently flexible that no modifications are necessary to accommodate such units. For example, while the design and construction of groundwater monitoring systems may be technically more challenging, the final standards already allow for the construction of a multi-unit system. The performance standards and technical specifications laid out in the technical criteria developed for this rule are equally as applicable to overfills (and as protective) as to other new units. In essence, EPA is retaining the approach from the proposal that overfills will need to comply with both the requirements applicable to the closure of surface impoundments or landfills, and with all of the technical requirements applicable to new landfills. Thus, overfills cannot be constructed unless the underlying foundation—*i.e.,* the existing CCR surface impoundment has first been dewatered, capped, and completely closed. And because overfills are considered to be "new CCR landfills," the design and construction of such units must comply with the technical requirements that address foundation settlement, overall and side slope stability, side slope and subgrade reinforcement, and leachate collection and groundwater monitoring system requirements, which will all need to be evaluated independent of the underlying CCR unit to ensure that the overfill design is environmentally protective. This evaluation must also be certified by a qualified professional engineer.

Under the location standards applicable to new CCR units, subgrade soils must be capable of providing stable structural support to the new liner system. A foundation composed of unconsolidated materials, such as CCR that is susceptible to slip-plane failure, is an unstable area (man-made) and, under provisions of this rule, is therefore a prohibited location for new CCR units. The TVA Kingston ash fill failure was at least partly attributable to slip-plane failure of saturated CCR that made up the subgrade and foundation beneath the unit.

Similarly, prudent and standard engineering practice for new CCR landfills requires that the base and side slopes of the overlying CCR landfill be able to maintain the structural integrity of the unit. If necessary, the subgrade should be reinforced with a geotextile fabric, or otherwise improved, to stabilize existing CCR in the underlying unit and to minimize tensile strain in the liner system. Slopes should be reinforced to prevent downhill sliding and to protect the leachate drainage system.

EPA is aware from comments that at least one facility is consolidating wet CCR in an active CCR surface impoundment through placement of dry ash over the wet CCR, and thereby converting the impoundment to a dry landfill, without stabilizing the CCR in the unit or capping the unit. This practice will no longer be permitted under the final rule criteria. Although no modifications were determined to be necessary to the individual technical criteria, EPA has added specific provisions that clarify the status of overfills, and clearly prohibit construction of a CCR landfill over a CCR surface impoundment unless the CCR in the underlying unit has first been dewatered and the unit is capped and completely closed. Dewatering, capping and closure of the underlying CCR unit prior to construction of the overlying CCR landfill renders the CCR overfill less susceptible to slip-plane failure. Conversion of an impoundment to a landfill without these measures involves a complex construction process that is highly site specific; EPA was unable to develop sufficiently objective performance standards that could be

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independently verified outside of a supervised permit program. Because this rule is self-implementing EPA is, therefore, prohibiting construction of new CCR landfills over operational CCR surface impoundments to prevent the creation of structurally unstable units that could lead to catastrophic failures.

*E. Design Criteria—Structural Integrity*

Under the design criteria requirements, EPA proposed to establish structural stability standards for existing and new CCR surface impoundments and lateral expansions of these units based on a combination of existing federal programs and requirements applicable to dam safety. The proposed rule was largely based on the requirements promulgated for coal slurry impoundments regulated by the MSHA at 30 CFR 77.216. (See 75 FR 35176.) EPA also developed aspects of the proposal based on the USACE and FEMA's dam safety programs. Consistent with the MSHA requirements, EPA proposed that existing and new CCR surface impoundments that could impound CCR to an elevation of five feet or more above the upstream toe of the structure and have a storage volume of 20 acre feet or more, or that impound CCR to an elevation of 20 feet or more above the upstream toe of the structure would be required to provide detailed information on the history of construction of the existing CCR surface impoundment and to meet certain performance standards. Specifically, facilities would need to (1) develop plans for the design, construction, and maintenance of existing impoundments, (2) conduct periodic inspections by trained personnel knowledgeable in impoundment design and safety, and (3) provide an annual certification by an independent registered professional engineer that all construction, operation, and maintenance of impoundments is in accordance with the approved plan.

EPA also proposed to require the facility to obtain certification from a professional engineer that the "design of the CCR surface impoundment is in accordance with current, prudent engineering practices for the maximum volume of CCR slurry and CCR wastewater which can be impounded therein and for the passage of run-off from the design storm which exceeds the capacity of the CCR surface impoundment. To support this performance standard, EPA proposed to require the facility to conduct specific analyses, and to provide information on critical structures. This includes the proposed requirements to compute the minimum factor of safety for slope stability of the retaining structures of the unit, including the methods and calculations used to determine each factor of safety, and to provide information on the physical and engineering properties of the foundations of the CCR surface impoundment, any foundation improvements, drainage provisions, spillways, diversion ditches, outlet instrument locations and slope protections, and area capacity curves. EPA proposed to require more extensive information from new CCR surface impoundments addressing the design, construction, and maintenance of the new CCR unit, recognizing that such information may not be available for existing units.[77] In addition, EPA proposed to require existing and new CCR surface impoundments of a specified size to calculate and report the hazard potential classification of the unit. Finally, EPA proposed that any CCR surface impoundments classified as having a high or significant hazard potential, as certified by an independent registered professional engineer, be required to develop and maintain an Emergency Action Plan defining the responsible persons and actions to be taken in the event of a dam safety emergency.

The Agency solicited comment on a number of issues relating to the proposed structural stability requirements. In particular, the Agency solicited comment on the scope of these requirements and whether they should apply to all CCR surface impoundments regardless of height and/or storage volume or whether EPA should adopt, as proposed and consistent with the MSHA requirements, the size cut-off described in the proposed rule; *i.e.,* impounding CCR to an elevation of five feet or more above the upstream toe of the structure and have a storage volume of 20 acre feet or more, or impounding CCR to an elevation of 20 feet or more above the upstream toe of the structure.

EPA also solicited comment on several alternative strategies for regulating the structural stability of CCR surface impoundments in lieu of regulation under RCRA subtitle D. The first alternative involved using NPDES permits rather than RCRA regulations to address dam safety and structural integrity. The second strategy would eliminate the structural integrity requirements from the RCRA subtitle D rule and, instead, have EPA establish and fund a program for conducting annual (or at some other frequency) structural stability assessments of CCR surface impoundments having a "high" or "significant" hazard potential rating as defined by criteria developed by the USACE for the NID. EPA would conduct these assessments and, using appropriate authorities already available under RCRA, CERCLA, and/or the Clean Water Act, would require facilities to respond to issues identified with their CCR surface impoundments. The rationale behind this suggested approach was that annual inspections would be far more cost effective than the phase-out of CCR surface impoundments—approximately $3.4 million annually for annual assessments, as compared to the $876 million annual cost of a rule that also phased out CCR. EPA also solicited comments on the effectiveness of this approach in ensuring the structural integrity of CCR surface impoundments. (See for example: 75 FR at 35176, 35223.)

On October 21, 2010, EPA published a NODA announcing that EPA intended to consider the information that had been developed through the Agency's Assessment Program as part of the CCR rulemaking. The NODA described the Assessment Program, and solicited comment on "the extent to which both the CCR surface impoundment information collection request responses and assessment materials on the structural integrity of these impoundments should be factored into EPA's final rule on the Disposal of Coal Combustion Residuals from Electric Utilities." (See 75 FR 35128.) This included the responses to information requests that EPA originally sent to electric utilities, as well as reports and materials related to the site assessments developed through the Assessment Program. At that time, EPA had completed the assessments and the final reports for 53 units. On August 2, 2013, EPA published another NODA soliciting public comment on the additional assessments that had been completed since the 2010 NODA. In all, this included draft and final reports for a total of 522 units and 209 facilities. EPA again solicited comment on the extent to which this information should be taken into account as part of this rulemaking.

EPA received numerous comments on the proposed structural stability requirements. Many of these fell within two general areas: (1) EPA's approach of

[77] In the proposed rule under proposed § 257.71—Design criteria for existing CCR surface impoundments, the Agency only required the hazard potential classification for which the facility is designed and a detailed explanation of the basis for the classification (§ 257.71(d)(1)) "as may be available" (§ 257.71(d)). Similarly the computed minimum factor of safety for slope stability of the CCR retaining structure(s) and the analyses used in the determination (§ 257.71(d)(11) "as may be available" (§ 257.71(d)).

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establishing the structural stability requirements, along with EPA's proposed reliance on MSHA's size thresholds to determine the applicability for the majority of structural stability requirements; and (2) the level of detail laid out in the technical criteria themselves.

With respect to the overall regulatory approach, the majority supported both the concept of structural stability requirements for existing and new CCR surface impoundments, and the adoption of the MSHA size threshold for complying with the majority of the structural stability requirements. EPA received comments from a number of state entities (the Association of State Dam Safety Officials (ASDSO) and the Association of State and Territorial Solid Waste Management Officials (ASTSWMO)) suggesting that EPA incorporate federal dam safety guidelines rather than rely solely on MSHA's dam safety guidelines. Commenters were concerned that the MSHA regulations "only exist to protect miners on mine property, and not the downstream public." They urged that any EPA regulation also include consideration of hazards to the downstream public. These commenters also requested that EPA "incorporate specific safety standards consistent with the Federal Guidelines for Dam Safety," referencing standards contained in FEMA documents 93, 333, 64, 94 and 65.

Little support was expressed for the alternative strategies presented in the proposal for addressing structural stability. Some comments were received suggesting additional alternatives. One commenter suggested that EPA consider limiting the volume of "primary containment ponds" to 10 acre-feet, reasoning that this provision would likely eliminate much of the concern regarding catastrophic failures, like TVA, and actually reduce the amount of slurry released in the event of a structural failure. Other commenters argued that EPA should limit the structural requirements to CCR surface impoundments both meeting the proposed size threshold and having a hazard potential classification of "high" or "significant" hazard potential rating based on FEMA's criteria for dam safety.[78] Commenters argued that a failure of a CCR surface impoundment with a "low hazard potential classification" posed only a low risk for on-site economic or environmental losses and would avoid the imposition of costly, arbitrary and unnecessary regulatory burdens on the owner or operator. In addition, commenters contended that this regulatory approach would be consistent with many state dam regulatory programs that apply dam integrity standards only to "high" or "significant" potential hazard facilities and would promote consistency with existing state controls.[79] Several commenters also suggested that EPA consider adding regulatory language or preamble discussion to assist owners or operators of CCR surface impoundments in interpreting the specific technical requirements in the regulation.

EPA disagrees with the suggestion that the Agency finalize a mandatory size limitation for operating CCR surface impoundments. While limiting the volume of CCR surface impoundments to ten acre-feet would limit the volume of CCR released in the event of a structural failure, limiting the size of CCR surface impoundments to 10 acre-feet may not always be practicable; nor does EPA believe that such a restriction is truly necessary to ensure that the section 4004(a) standard will be met. Many CCR surface impoundments are much larger than ten acre-feet and have been operating for many years without a structural failure. While EPA acknowledges that this fact in no way guarantees that a failure will not occur, the Agency is convinced that the implementation of all of the combined regulatory requirements in this rule (*e.g.,* location criteria, structural integrity, inflow design flood controls and inspection requirements) provides the necessary safeguards that will ensure that CCR surface impoundments are designed, constructed, operated, and maintained to minimize the risks associated with a catastrophic release of impounded CCR due to structural failure. While limiting the size of CCR surface impoundments will reduce risks because there will be a lower volume of waste in the unit, the Agency is not convinced that, in practice, such a requirement would meaningfully reduce the risks at many facilities. EPA expects that such a restriction would only cause facilities to construct either several small units or a multi-unit system. Failure of one unit can lead to progressive failure of other units in the system, and thus, ultimately this may not reduce the total volume of waste that could be released into the environment. EPA also disagrees that structural stability requirements should only apply to "high" or "significant" potential hazard facilities. Similarly, EPA disagrees with commenters that structural integrity requirements should only apply to owners or operators of CCR surface impoundments that both meet the specified size criteria and have either a high hazard or significant hazard potential classification. Even for CCR units with a low hazard potential classification, EPA is still concerned with the risk to human health and the environment from any structural failure of a CCR unit. As discussed previously in Unit VI.C of this document, the environmental effects of the failure of even a low hazard potential impoundment can still be significant, given the size of these units, the nature of the material in the unit, and the potential volumes that could be released. Contamination of surface waters and groundwater resources is still a significant threat when CCR units of this size fail, irrespective of the lower likelihood that a release will affect human health, as reflected in the low hazard potential classification. Consequently, one focus of this rule is preventing any release, catastrophic or otherwise, of CCR to the environment, and limiting all structural stability requirements commenters suggested would be inconsistent with this goal.

The Agency agrees that the final regulation should incorporate provisions that address the hazards to the downstream public. Accordingly, the final rule incorporates a number of provisions consistent with the FEMA Guidelines, including a requirement that owners and operators know each CCR unit's hazard potential classification, as this is part of owners and operators' responsibility to actively ensure the integrity of their CCR unit(s) and that their operations do not endanger human health or the environment. EPA also agrees that the requirements should be differentiated based on the potential severity of the consequence posed by the unit's failure, and therefore the hazard potential can be relevant in determining the stringency of particular requirements. However, the hazard potential is, at best, only an indicator of the potential damage that may be incurred from the

[78] See: *Federal Guidelines for Dam Safety: Hazard Potential Classification for Dams,* Federal Emergency Management Agency ("FEMA") (reprinted January 2004). Under the FEMA dam safety classification system, a "low hazard potential classification" means that failure or mis-operation of the impoundment "results in no probable loss of human life and low economic and/or environmental losses. Losses are principally limited to owner's property."

[79] See *e.g.,* New Mexico Rules and Regulations Governing Dam Design, Construction and Dam Safety (*e.g.,* requiring dam site security, an instrumentation plan for monitoring and evaluating dam performance, and an operation and maintenance manual and emergency action plan only for dams with a high or significant hazard potential); see also NMAC sections 19.25.12.11(G)–(J).

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structural failure of the unit, and so EPA has generally not relied on hazard potential as the sole basis for determining the structural integrity requirements that are necessary for a CCR unit.[80] Although the hazard potential classification can serve as a proxy for the amount of water and CCR that could potentially be released to the environment in the event of a CCR surface impoundment failure, the amount of water and CCR potentially released is more directly correlated to the actual height and storage volume of the CCR surface impoundment. In addition, it is widely recognized that the hazard potential classification of an individual unit can often fail to encompass the overall magnitude of a release on human health and the environment. CCR surface impoundments can frequently be part of a facility's run-off system that is responsible for routing surface waters to a drainage basin or watershed. As previously discussed, the failure of a CCR unit that is part of such a system has the potential to inundate downstream surface water units and water bodies, resulting in progressive failures of other units, including other CCR surface impoundments at the facility, which in turn can have a much greater environmental impact than the failure of just the one unit for which a hazard potential classification was made. Using a "height and/or volume" threshold to determine the applicability of the structural integrity criteria ensures that CCR units with the potential to cause these progressive failures in downstream surface water management units are appropriately overseen and regulated. CCR surface impoundments exceeding a specified height and/or capacity threshold also pose a higher degree of risk of release of CCR to the environment than other types of CCR surface impoundments (*e.g.,* incised or "small" CCR units). For all of these reasons, the size of the CCR unit, rather than the hazard potential classification, is the best indicator of potential severity of release of CCR to the environment and should therefore be the primary basis on which structural integrity criteria are applied. As such, EPA is promulgating, as proposed, a regulatory strategy that establishes some requirements for all CCR surface impoundments, but relies primarily on size as the basis for determining the majority of the specific technical criteria for minimizing risk from structural failure.

Regarding the second major issue presented in the comments, as noted previously, EPA received comments requesting the Agency to provide either more specific regulatory language or further guidance in the preamble, so that parties could certify that the CCR surface impoundment met the rule's overall performance standard. Commenters contended that guidance would be particularly critical if EPA did not establish more specific technical criteria, as owners or operators will be vulnerable to lawsuits for non-compliance. In addition, state officials requested that EPA adopt more specific standards consistent with those adopted under FEMA's Federal Guidelines for Dam Safety. As discussed throughout this section in more detail, EPA has adopted clarifications to the regulation, particularly in the sections on structural stability and safety factors, to more precisely lay out the specific technical standards that are considered to be the "generally accepted and recognized good engineering practices" that must be met. EPA relied extensively on existing MSHA requirements, FEMA's Federal Guidelines for Dam Safety, and guidance issued by the U.S. Army Corps of Engineers, as they were applied throughout EPA's Assessment Program, to supplement the technical detail originally contained in the proposed rule. EPA has also modified the criteria, where necessary, so they better reflect the information and experience developed through the Assessment Program, *e.g.,* the engineering criteria used to evaluate the CCR surface impoundments and to make recommendations to improve the structural stability of the units.

In this rule, the Agency is finalizing structural integrity criteria to ensure that CCR surface impoundments are designed, constructed, operated, and maintained in a manner that ensures the structural integrity of the CCR surface impoundment throughout its active life (*i.e.,* through closure of the CCR unit), detects actual or potential releases of CCR as early as practicable, and prevents catastrophic failures. Many of the requirements have been adopted without revision from the proposed rule for some requirements, however, as noted EPA has provided additional language to clarify the final regulation. These clarifications have been made in response to comments urging EPA to finalize regulatory requirements that were more precise or sufficiently objective (*i.e.,* a specific standard of performance) to allow a qualified professional engineer to reasonably certify that the requirements of the rule have been met. These specific regulatory clarifications are discussed throughout this section.

A further change is that the final rule requires facilities to periodically reassess several elements of the structural integrity performance standards (*i.e.,* re-assess every five years). Finally, in contrast to the programs established by MSHA and FEMA, the final rule establishes certain minimum requirements for all CCR surface impoundments. This is based on the fact that, unlike the dams regulated under other federal programs, the material in all CCR units is harmful, so even small releases can present environmental and human health concerns. But the majority of the structural integrity requirements vary depending on whether the CCR surface impoundment or lateral expansion exceeds particular size thresholds. The rulemaking record clearly demonstrates that these larger CCR surface impoundments present a greater risk of catastrophic failure, and therefore require a more robust set of regulatory requirements to ensure their continued structural integrity. The final rule's implementation of a size threshold for structural integrity requirements is consistent with the approach taken by the majority of dam safety programs and regulation.

These modifications are being made to better reflect the protections necessary to ensure that: (1) Structural integrity is maintained throughout the operational life of a CCR unit; and (2) the risk of catastrophic failure is minimized. The changes being made in this rule have been directly influenced by comments received, the observations and the conclusions drawn from EPA's Assessment Program, and the recommendations made by both MSHA and FEMA regarding dam safety. They are also generally consistent with the regulatory requirements of many other state and other federal agencies regulating dam safety.

1. Overview of Technical Criteria

Except for incised units, owners or operators of all existing and new CCR surface impoundments and any lateral expansion of these CCR units are required to: (1) Place a permanent identification marker on or immediately adjacent to the CCR units with the name associated with the CCR unit and the name of the owner or operator of the CCR unit; (2) conduct an initial hazard potential assessment to determine the current hazard potential classification of

[80] For example, EPA relied on hazard potential to trigger the requirement for an Emergency Action Plan, which will identify the actions necessary to minimize damage to life and property. As damage to life and property are the factors directly addressed in hazard potential classification, reliance on the classification is an appropriate determinant for this requirement.

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the CCR unit; (3) conduct periodic (*i.e.,* every five years) hazard potential re-assessments; (4) develop an Emergency Action Plan (EAP) if the hazard potential classification of the CCR unit is classified as either a high- or significant hazard potential; and (5) maintain the CCR unit with vegetated slopes or other forms of slope protection.

Owners or operators of CCR surface impoundments that either have a height of five feet or more and a storage volume of 20 acre feet or more, or a height of 20 feet or more are required to comply with the following additional structural integrity criteria: (1) Document the design and construction of the CCR surface impoundment; (2) conduct an initial structural stability assessment; (3) conduct an initial safety factor assessment; and (4) conduct periodic (not to exceed five years) structural stability and safety factor assessments.[81] Owners and operators of CCR units that fail to make the safety factor assessment or fail to meet the factors of safety specified in the rule must stop placing CCR in the unit and initiate closure.

The structural integrity requirements of the final rule require the compilation of construction history of the existing CCR surface impoundment within one year of the effective date of the rule.

Within two months of the effective date of the rule, the structural integrity requirements (§ 257.73) state that the owner or operator must install a permanent marker on the existing CCR surface impoundment. This timeframe is being promulgated as proposed, as EPA did not receive comments on the timeframe for installation of a permanent marker.

2. Structural Integrity Requirements Applicable to All CCR Surface Impoundments

a. Hazard Potential Classification Assessments

A hazard potential classification provides an indication of the potential for danger to life, development, or the environment in the event of a release of CCR from a surface impoundment. In this rule, an owner or operator of any existing or new CCR surface impoundment or any lateral expansion of a CCR surface impoundment must determine which of the following hazard potential classifications characterizes their particular CCR unit.[82] These classifications are: a high hazard potential CCR surface impoundment, a significant hazard potential CCR surface impoundment; and a low hazard potential CCR surface impoundment and are defined as follows:

- *High hazard potential CCR surface impoundment* means a diked surface impoundment where failure or mis-operation will probably cause loss of human life.
- *Significant hazard potential CCR surface impoundment* means a diked surface impoundment where failure or mis-operation results in no probable loss of human life, but can cause economic loss, environmental damage, disruption of lifeline facilities, or impact other concerns.
- *Low hazard potential CCR surface impoundment* means a diked surface impoundment where failure or mis-operation results in no probable loss of life and low economic and/or environmental losses. Losses are principally limited to the surface impoundment's owner's property.

Owners and operators of all CCR surface impoundments must determine each unit's hazard potential classification through a hazard potential classification assessment. Hazard potential classification assessments must be certified by a qualified professional engineer and documentation must be provided that supports the basis for the current hazard potential rating. An initial hazard potential assessment must be conducted within one year of the effective date of the rule for existing units and prior to the initial receipt of CCR in the unit for new units or lateral expansions. Hazard potential classifications, structural stability assessments, and safety factor assessments require significant planning and coordination, such as detailed site-work and investigations, modeling and analysis, design and construction planning and implementation, and post-construction investigation. Many of these efforts take several months to complete, compounded by the fact that much of the work cannot be completed in cold-weather or heavy-rain seasons.

As commenters noted, it is imperative that the owner or operator maintain a current assessment of a unit's hazard potential classification, rather than develop a single one-time classification "for which the facility was designed." (See proposed § 257.71(d)(10).) Moreover, FEMA recommends that a unit's hazard potential classification should be reviewed no less frequently than every five years in order to take into account changes in the factors that are the basis for which a hazard potential classification is made (*e.g.,* changed reservoir or downstream development).[83] Based on this information, EPA determined that a periodic reassessment of a CCR surface impoundment's hazard potential classification is a necessary component in maintaining the accuracy of the unit's hazard potential classification, as well as the overall safety of the unit. Consequently, EPA is requiring the owner or operator of a CCR surface impoundment to reassess the hazard potential classifications of their CCR unit and to have that classification, certified by a qualified professional engineer, at least every five years.

EPA has continued to rely on FEMA requirements as the basis for general CCR surface impoundment safety requirements, *e.g.,* inflow design flood selection, inspection criteria, earthquake analyses and design for several reasons: (1) Structural failure risks for CCR surface impoundments are similar to the risks from the larger dam universe for which FEMA intends its guidance; and (2) risks to downstream development from CCR surface impoundment failures are equal or similar to those presented by other types of dams' failures.

In this rule, hazard potential classifications define the consequences in the event of a failure of a CCR surface impoundment. The classification is separate from the structural stability of a CCR unit or the likelihood of the impoundment failing. A surface impoundment that meets or exceeds all of the structural stability criteria and safety factors of this rule would still be classified as "high hazard potential" if, in the event of failure, loss of life would be likely to occur.

[81] *Height* means the vertical measurement from the downstream toe of the CCR surface impoundment at its lowest point to the lowest elevation of the crest of the CCR surface impoundment.

[82] Incised CCR surface impoundments are not required to perform a hazard potential classification assessment because hazard potential classifications are based on the failure of a dam, diked surface impoundment, or other water-retaining structure and the adverse incremental impacts that may result from the failure. Because incised CCR surface impoundments, as defined in this rule, do not have a diked portion which may fail, the incised CCR surface impoundment cannot have a hazard potential classification. This final rule covers CCR surface impoundment failures and releases due to other potential failure modes (*i.e.,* which do not pose an immediate catastrophic threat to human health or the environment), such as a release through the liner of the unit or through failure of underlying structures, in the location restrictions, design criteria, and operating criteria of the rule.

[83] See: *Federal Guidelines for Dam Safety: Hazard Potential Classification for Dams,* Federal Emergency Management Agency ("FEMA") (reprinted January 2004). Under the FEMA dam safety classification system, a "low hazard potential classification" means that failure or mis-operation of the impoundment "results in no probable loss of human life and low economic and/or environmental losses. Losses are principally limited to owner's property."

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The hazard potential classification of the CCR surface impoundments is an essential element in determining how to properly design, construct, operate, and maintain a CCR surface impoundment. As such, the final rule bases the stringency of some technical requirements, in part, on the potential for adverse impacts on the failure of the CCR unit, as quantified by the hazard potential classification of this rule. Specifically, the requirements become more stringent as the potential for loss of life and/or property damage increases. This is reflected in both the criteria established under the structural stability assessments, *.e.g.,* where the combined capacity of all spillways must adequately manage flow during and following peak discharge from the specified inflow design flood based on the hazard potential classification of the unit—and in the hydrologic and hydraulic capacity requirements, which are similarly specified based on the hazard potential classification of the CCR unit (see §§ 257.73(d)(2)(v); 257.74(d)(2)(v) and 257.82 respectively).[84] Additionally, high and significant hazard potential CCR surface impoundments must develop a written Emergency Action Plan which establishes emergency action procedures in the event of a previously defined emergency.

b. Emergency Action Plan

An Emergency Action Plan (EAP) is a document that identifies potential emergency conditions at a CCR surface impoundment and specifies actions to be followed to minimize loss of life and property damage. Typically an EAP includes: (1) Actions the owner or operator will take to moderate or alleviate a problem at the CCR unit; (2) actions the owner or operator will take, in coordination with emergency management authorities, to respond to incidents or emergencies related to the CCR surface impoundment; (3) procedures owner or operators will follow to issue early warning and notification message to responsible downstream emergency management authorities; (4) inundation maps to allow owners and operators of the CCR unit and emergency management authorities to identify critical infrastructure and population-at-risk sites that may require protective measures, warning and evacuation planning; and (5) delineation of the responsibilities of all those involved in managing an incident or emergency and how the responsibilities should be coordinated and implemented.[85] As FEMA guidance suggests, and EPA reiterates here, the level of detail in the EAP should be commensurate with the potential impact of a surface impoundment failure or other operational incident (*e.g.,* its hazard potential classification). A surface impoundment with low potential hazard impact should not require an extensive evaluation or be subject to an extensive planning process, while high-hazard and significant hazard surface impoundments would typically require a much larger emergency planning effort. In addition, high hazard and significant hazard surface impoundments tend to involve more entities that must coordinate responsibilities and greater efforts would generally be necessary to effectively respond to an incident with such a surface impoundment than to a similar incident involving a low-hazard surface impoundment. As such, every EAP must be tailored to specific site conditions.

EPA is promulgating, as proposed, a provision that requires any CCR surface impoundment that is determined by the owner or operator, through the certification by a qualified professional engineer, to be either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment to prepare and maintain a written EAP. While EPA agrees that the level of detail contained in an EAP should be commensurate with its hazard potential rating, EPA has concluded that at a minimum, the EAP must: (1) Define responsible persons and the actions to be taken in the event of a CCR surface impoundment-safety emergency; (2) provide contact information for emergency responders, including a map which delineates the downstream area which would be affected in the event of a failure and a physical description of the CCR surface impoundment; (3) include provisions for an annual face-to-face meeting or exercise between representatives of the owner or operator of the CCR unit and the local emergency responders; and (4) define conditions that initiate implementation of the EAP and define emergency response actions which must be implemented upon the detection of these conditions, including all persons responsible for the implementation of the emergency response actions. The first three of these four requirements were proposed as part of the EAP and are being promulgated without revision. The fourth requirement, which requires facilities to explicitly define the conditions by which the EAP is activated, was inadvertently omitted from the proposal, and is being added to the final rule to ensure that the EAP includes at least the basic requirements necessary to function effectively.

The owner or operator must amend the written EAP whenever there is a change in conditions that would substantially affect the written EAP in effect, *e.g.,* change in personnel, change in emergency responder contact information, a change in the CCR surface impoundments' designation from a significant-hazard potential classification to a high-hazard potential classification, or the vertical expansion of the CCR unit (*i.e.,* increase in the amount of CCR that potentially could be released.) Consistent with the requirements for hazard potential classification reassessments, the Agency is requiring, at a minimum that the EAP be reassessed at least every five years. If an owner or operator determines that, as part of it periodic hazard potential re-assessment that the unit no longer is classified as a high-hazard or a significant-hazard potential classification, but is now classified as a low hazard potential CCR surface impoundment, then the owner or operator of the CCR unit is no longer subject to the requirement to prepare and maintain an EAP, effective when such documentation is placed into the facility's operating record. If, however, during the reassessment effort it is determined that an existing CCR unit classified as a low hazard potential has been re-classified as either a significant-hazard or high-hazard potential, the owner or operation must prepare an EAP for the CCR unit within six months of completing such a periodic hazard potential re-assessment.

Although the owner or operator is responsible for developing and maintaining the EAP, which must be certified by a qualified professional engineer, the plan should be developed and implemented in close coordination with all applicable emergency management authorities, including the appropriate local, state, and federal authorities. Generally, these coordination efforts, along with the EAP, provide emergency management authorities with the necessary information to facilitate the implementation of their responsibilities, and so, it is vital that the development of the EAP be coordinated with emergency responders and other entities, agencies, and jurisdictions, as

[84] A high-hazard potential impoundment, for example, must be designed with sufficient spillway capacity to manage flow from the probable maximum flood, whereas a low hazard potential unit need only account for a 100 year flood.

[85] See: "Federal Guidelines for Dam Safety: Emergency Action Planning for Dams," FEMA 64/ July 2013.A.

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appropriate. After the initial EAP has been developed and placed in the operating record and on the owner or operator's internet site, it should be periodically reviewed and updated on a regular basis, as it can become outdated and ineffective. While the Agency is only requiring the EAP to be re-assessed every five years, it is recommended that the EAP be reviewed at least annually for appropriateness, accuracy, and adequacy so as to remain current. EPA recommends that the EAP be promptly updated to address changes in personnel, contact information and/or significant changes to the facility or emergency procedures. Even if no revisions are necessary, the review should be documented.

The initial EAP must be prepared within 18 months from the effective date of the rule. In order to prepare an EAP, the owner or operator must accurately and comprehensively identify potential failure modes and at-risk development, and therefore completion of the emergency action plan needs to follow the completion of the initial hazard potential classification, structural stability assessment, and safety factor assessments, during which this information will be generated.

c. Vegetated Slopes of Dikes and Surrounding Areas

EPA proposed to require both new and existing CCR surface impoundments that exceed the MSHA size thresholds to document the slope protection measures that have been adopted and to compute the minimum factors of safety for slope stability, in order to support the certification from an independent professional engineer that the unit has been designed in accordance with "generally accepted engineering standards." EPA is promulgating the requirement that all CCR surface impoundments have adequate slope protection because EPA determined through the Assessment Program that slope protection is an essential element in preventing slope erosion and subsequent deterioration of CCR unit slopes. EPA is requiring slope protection for all units, not just units exceeding the size threshold of the final rule, because EPA has identified that slope protection on CCR units is a generally accepted good practice which reduces the occurrence of erosion, degradation of surface waters due to run-off from the CCR unit, enhances slope stability, and that vegetated cover is an easily accomplished practice in the vast majority of climates where CCR surface impoundments are located. In conducting the Assessment Program, the protective cover of slopes of the CCR surface impoundment was determined to be relevant to the overall condition rating of all units, irrespective of size. This is consistent with FEMA guidance, which also lays out specifications for the ideal vegetative cover for a dam. EPA has adopted this requirement to be consistent with its findings from the Assessment Program, and in response to comments, and has elaborated on the slope protection measures necessary to achieve the factors of safety. The final rule provides performance standards drawn primarily from FEMA guidance, as applied during the Assessment Program.

All CCR surface impoundments are required to be designed, constructed, operated, and maintained with adequate slope protection to protect against surface erosion at the site. Slope protection is necessary to ensure that dike or embankment erosion does not occur. Additionally, slope protection is required of all CCR surface impoundments to maintain the stability of the CCR surface impoundment slope under rapid drawdown events [86] and low pool conditions of water bodies that may abut the CCR surface impoundment and are outside the control of the owner or operator, *e.g.,* a natural river which the slopes of the CCR surface impoundment run down to and abut. The slope protection can act as a stabilizer in the slope of the embankment during rapid drawdown events. Adequate slope protection can be achieved in most climates through simple vegetation, typically a healthy, dense stand of low-growing grass, or other similar vegetative cover. In arid climates where the upkeep of vegetation is inhibited, alternate forms of slope protection, including rip-rap, or rock-armor is typically used. Additional slope protective measures are available and effective in certain circumstances, including but not limited to rock, wooden pile, or concrete revetments, vegetated wave berms, concrete facing, gabions, geotextiles, or fascines.

The owner or operator must ensure that the slopes of the CCR surface impoundment are protected from erosion by appropriate engineering slope protection measures. It is recommended throughout embankment technical literature that vegetative cover not be permitted to root too deeply, precipitating internal embankment issues. The rule requires a vegetative cover limit to prevent the establishment of rooted vegetation, such as a tree or a bush on the CCR surface impoundment slope. EPA has concluded that a vegetative cover of no more than six inches above the face of the embankment is adequate and is the uppermost limit for vegetative cover height for this final rule. In developing this requirement, EPA was strongly influenced by information contained in the FEMA document entitled, "Technical Manual for Dam Owners: Impacts of Plants on Earthen Dams" [87] in determining an appropriate vegetative cover height for CCR surface impoundments. Six inches represents a vegetative height which prevents any trees, bushes, or shrubbery from rooting deeply enough to warrant additional removal measures outside of simple mowing. Furthermore, the height prescribed by the final rule represents a maximum height of vegetative cover to allow for adequate observation of the slope of the CCR unit during inspection. Vegetative cover in excess of six inches above the slope of the dike would prevent the adequate observation of the slope of the CCR unit and detection of structural concerns such as animal burrows and minor sloughs, amongst others concerns. Consistent with FEMA guidance, as applied during the Assessment Program, other slope protection, such as rock armoring or vegetated berms, would also be considered adequate.[88]

3. Structural Integrity Criteria Applicable to CCR Surface Impoundments Exceeding a Specific Size Threshold

The structural integrity criteria discussed in this section of the preamble apply to existing and new CCR surface impoundments and any lateral expansion with: (1) A height of five feet or more and a storage volume of 20 acre-feet or more; or (2) a height of 20 feet or more. The rule defines *height* as the vertical measurement from the downstream toe of the CCR surface impoundment at its lowest point to the lowest elevation of the crest of the CCR surface impoundment. The *downstream toe* is defined as the junction of the downstream slope or face of the CCR surface impoundment with the ground surface. This final rule considers the lowest elevation of the crest of the CCR

[86] This rapid drawdown is not included in the rule's factors of safety assessments. The protection against rapid drawdown requirement of this provision is concerned with the rapid drawdown of adjacent water bodies acting upon the downstream slope of the CCR surface impoundment rather than the rapid drawdown of the impounded reservoir of the CCR surface impoundment acting upon the upstream slope of the CCR surface impoundment.

[87] *http://www.fema.gov/media-library-data/20130726-1446-20490-2338/fema-534.pdf.*

[88] *http://www.fema.gov/media-library-data/20130726-1446-20490-2338/fema-534.pdf.*

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surface impoundment to be the maximum storage elevation of the reservoir or pool of the CCR unit, *e.g.,* the invert of the lowest-elevation spillway. EPA is implementing this size threshold because it comports with thresholds established by other federal and state agencies regulating dam integrity and/or safety. Specifically, for the implementation of the size threshold of this final rule, EPA relied on the identical size parameters, *i.e.,* height of five feet and capacity of 20 acre-feet, which is promulgated in MSHA coal slurry impoundment regulations in 30 CFR 77.216.

In the proposed rule, EPA used the size cut-off promulgated by MSHA in their dam safety requirements for coal slurry impoundments at 30 CFR part 77. In proposing this cut-off, EPA reasoned that the MSHA requirements affecting coal slurry impoundments were directly applicable and relevant to CCR surface impoundments and provided a size threshold that, when applied to the rule's structural integrity criteria, would generally meet RCRA's mandate to ensure protection of human health and the environment by minimizing the potential for catastrophic failure. Specifically, EPA proposed that surface impoundments: (1) Impounding CCR to an elevation of five feet or more above the upstream toe of the structure and can have a storage volume of 20 acre-feet or more; or (2) impounding CCR to an elevation of 20 feet or more above the upstream toe of the structure would be subject to the structural stability criteria. EPA also proposed to define *upstream toe* as the junction of the upstream slope of the dam with the ground surface, with the height of the CCR unit measured from the upstream toe or water-borne toe of the CCR unit.

While little comment was received on adopting this size threshold or the accompanying definition of *upstream toe,* the Agency was concerned that the size threshold presented in the proposed rule did not reflect standard measuring protocols used by other federal agencies and the dam sector in determining the size of a dam or, in the case of this rule, surface impoundment. Of particular concern to the Agency was the fact that EPA's own Assessment Program was measuring the height of a CCR unit from the downstream toe rather than the upstream toe, which was specified in the MSHA regulatory requirement and the subsequent CCR proposed rule.

A review of MSHA, FEMA and the USACE regulations and guidance, as well as the guidance of several state agencies that oversee dam safety, revealed that dam or surface impoundment height is more appropriately measured from the downstream and not the upstream toe of the unit. EPA based this conclusion on the near-universal position of dam safety guidance that the downstream slope height of the dike is of primary concern in the design, construction, operation, and maintenance of the dam or surface impoundment. Virtually all of the dam safety regulations, including state and federal guidance and regulations, that EPA reviewed considered measured dam height to be taken from the downstream slope of the dike. Some of these guidance and regulations include FEMA "Federal Guidelines for Dam Safety," U.S. Army Corps "National Inventory of Dams," and MSHA Metal and Nonmetal Tailings and Water Impoundment Inspection requirements in 30 CFR part 56 and § 57.20010.[89] This information, coupled with the information on the methodology used in the Assessments Program, convinced the Agency that a revised description of the CCR surface impoundment size cutoff was necessary, specifically requiring the height of the CCR unit to be measured from the downstream toe.

a. Design and Construction Information

The first element of the structural integrity criteria applicable to CCR units exceeding the specified size threshold requires the owner or operator to compile and place in the operating record design and construction information pertaining to the CCR unit. Among other things, this provision requires the following documentation to be provided by the owner or operator: (1) The name of the owner or operator of the unit; (2) the name of the unit; and (3) any identification number assigned by the state. In addition, it requires that the owner or operator identify: (5) The location of the CCR unit on a U.S. Geological Survey Map or a topographic map of equivalent scale; (6) provide dimensional drawings of the CCR unit with pertinent engineering structures and appurtenances identified; (7) describe the purpose of the CCR unit; and (8) identify the name and size of the watershed affecting the CCR unit, if any. Detailed information is also required documenting: (9) The design and construction of the unit including dates and descriptions of each zone or stage constructed; (10) instrumentation used to monitor the operation of the CCR unit, (11) spillway and diversion design descriptions and construction specifications; and (12) provisions for surveillance, maintenance and repair of the CCR unit.

While these requirements apply to both existing and new CCR surface impoundments, existing CCR surface impoundments are required to compile this information only "to the extent available," within one year of the effective date of the rule. Conversely, new CCR surface impoundments or any lateral expansion must compile all of the information listed prior to the initial receipt of CCR. For existing CCR surface impoundments, EPA acknowledges that much of the construction history of the surface impoundment maybe unknown or lost. EPA's Assessment Program confirmed that many owners or operators of CCR units did not possess documentation on the construction history or operation of the CCR unit. Information regarding construction materials, expansions or contractions of units, operational history, and history of events was frequently difficult for the owners or operators to obtain. The Assessment Program also confirmed the Agency's initial assumption that this information, in many instances, will be difficult to compile. Therefore, in this rule, EPA is using the phrase "to the extent available" and clarifying that the term requires the owner or operator to provide information on the history of construction only to the extent that such information is reasonably and readily available. EPA intends facilities to provide relevant design and construction information only if factual documentation exists. EPA does not expect owners or operators to generate new information or provide anecdotal or speculative information regarding the CCR surface impoundment's design and construction history.

There are several other requirements under the design and construction criteria requiring clarification. First, the Agency is amending the requirement that all dimensional drawings of the CCR unit (see § 257.73(b)(vii) and § 257.74(b)(vii)) use a uniform scale of one inch equals 100 feet. After further consideration, EPA has deleted this requirement and has replaced the proposed scale of 1 inch equals 100 feet with the phrase "at a scale that details engineering structures and appurtenances relevant to the design, construction, operation, and maintenance of the CCR unit." EPA made this change in response to comments arguing that this level of detail was unnecessary. EPA agrees that, given the extremely large variety in the size of CCR units, a prescriptive scale for all drawings of all CCR units is not necessary in many cases; this level of detail would be excessive for most

[89] *http://www.msha.gov/regs/complian/PILS/2013/PIL13-IV-01.asp.*

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units. The Agency is also clarifying, (see § 257.73(b)(2) and § 257.74(b)(2)) that if an owner or operator determines that a significant change has occurred in the information/documentation previously compiled under this provision, the owner or operator must update the relevant information and place it in the operating record.

b. Types of Assessments

A second element of the structural integrity criteria is the requirement for specific technical assessments of the CCR unit. Consistent with the requirements outlined in the proposed rule, two technical assessments are required for all CCR units exceeding the specified size threshold: (1) A structural stability assessment; and (2) a safety factor assessment. The owner or operator of an existing CCR surface impoundment is required to conduct an initial assessment addressing both structural stability and safety factors within one year of the effective date of the rule. New CCR surface impoundments or any lateral expansion of a CCR unit are required to complete the initial assessment prior to placing CCR into the unit. Following the initial assessments, EPA is also requiring periodic re-assessments of both a CCR surface impoundment's structural stability and factors of safety. EPA proposed to require an annual recertification, but in a departure from the proposed rule, EPA is only requiring these re-assessments to be conducted on a regular basis, not to exceed once every five years. In making this regulatory change, the Agency has relied heavily on the dam safety guidance established by FEMA in the document titled, *Federal Guidelines for Dam Safety* that a formal inspection, including ". . . a review to determine if the structures (*i.e.,* CCR surface impoundments) meet current accepted design criteria and practices . . ." be taken at an interval not to exceed five years. EPA has interpreted this guidance to be applicable to both the structural stability assessment and the safety factor assessment.

A demonstration must be completed within the assessment period for the specific type of assessment. This means that, within this timeframe the owner or operator must demonstrate that the CCR unit meets all of the requirements of each type of assessment, as certified by a qualified professional engineer. It also means that the owner or operator must have taken all measures necessary to bring the unit into compliance with all of the requirements for assessments of this final rule within the assessment period. If the owner or operator cannot demonstrate that the unit meets these factors of safety (or otherwise fails to comply with the structural stability requirements) within the appropriate timeframe, the unit must initiate closure.

i. Periodic Structural Stability Assessments

In order to ensure the proper upkeep and operation of the CCR unit, the owner or operator must demonstrate that the CCR surface impoundment has been designed, constructed, operated and maintained to provide structural stability. Specifically, consistent with the proposal, the final rule requires the owner or operator to demonstrate that the design, construction, operation, and maintenance of the CCR surface impoundment is consistent with recognized and generally accepted good engineering practices for the maximum volume of CCR and water that can be impounded therein. As discussed previously, EPA has elaborated on this overall performance standard in response to comments from the engineers who would be required to make these certifications, urging EPA to specify more precisely the standards that must be met. Specifically the final rule focuses on the critical structural aspects of the CCR surface impoundment that EPA identified in the proposed rule, and identifies the minimum elements that a professional engineer must provide engineering details on or otherwise address. In certain cases, the final criteria identify specific engineering performance standards. EPA relied on existing MSHA requirements, FEMA dam safety guidance, and guidance issued by the USACE, as applied throughout EPA's Assessment Program to develop these criteria. Consistent with the proposal, these demonstrations must be certified by a qualified professional engineer. Each of these criteria is discussed in more detail below.

In addition to implementing adequate slope protection against erosion, which is a structural stability requirement applicable to all CCR units, the owner or operator of a CCR surface impoundment exceeding the specified size threshold must demonstrate that the unit, including any vertical and lateral expansions, is constructed with "stable foundations and abutments." A stable foundation is an essential element of surface impoundment construction and prevents differential settlement of the embankment which can result in adverse internal stresses with the embankment cross-section. Soils tend to consolidate when subjected to loadings for extended periods, which can lead to strain incompatibility, a phenomena which prevents the full development of peak strength of the foundation. The stability of foundations and abutments can be determined by engineering monitoring, representative soil sampling, and modeling. Similarly, cohesion between the abutments of the CCR surface impoundment and the embankment of the CCR surface impoundment is critical. Frequently, CCR surface impoundments are subject to cracking and excessive seepage and piping in the groins where the abutment and embankment meet. These adverse conditions may lead to further structural deficiencies which threaten the safety of the CCR surface impoundment.

Consistent with general engineering construction methodologies, the structural stability assessment also requires the owner or operator to determine whether the CCR surface impoundment has been mechanically compacted to a density sufficient to withstand the range of loading conditions in the CCR unit.[90] Compaction of a dike or embankment is considered essential, as the compaction of soils leads to an increase in density and subsequently strength. Soil mechanics theory has established that the density of a soil corresponds to the moisture content and strength of the soil. The rule requires the owner or operator make this determination for all dikes of a CCR surface impoundment.

EPA notes that a number of existing voluntary consensus standards are available that can be useful in making this determination. For example, ASTM D 698 establishes a performance standard of 95% of the maximum standard Proctor density. Similarly, ASTM D 1557 establishes a standard of 90% of the maximum modified Proctor density. Alternatively, in certain instances, such as soils consisting of more than 30% material retained on the ¾ in. sieve, Proctor testing is not appropriate and the relative density criteria can be met. In such cases, EPA recommends a 70% relative density. These specific soil compaction criteria are ubiquitous throughout engineering construction as sufficient to support engineered works based on the requirements. They are also consistent with the standards promulgated by the state of New Mexico's dam safety program in order to ensure proper compaction during construction of new CCR surface impoundments.

EPA recognizes that it would be highly difficult for owners or operators

[90] *http://www.publications.usace.army.mil/Portals/76/Publications/EngineerManuals/EM_1110-2-2300.pdf.*

of older units to certify with any certainty that the unit's construction meets the specific numeric compaction criteria found in the ASTM standards. New units, however, can easily meet these standards, and should therefore be designed and constructed to meet the numeric compaction criteria.

The owner or operator must also design, construct, operate, and maintain the CCR surface impoundment spillway or spillways with appropriate material so as to prevent the degradation of the spillway, as well as to ensure that the CCR surface impoundment has adequate spillway capacity to manage the outflow from a specific inflow design flood. In addition, a demonstration must be made that the CCR surface impoundment has been designed, constructed, operated, and maintained with inflow design flood controls and/or spillway capacity to manage peak discharge during and following inflow design floods. This demonstration is required to ensure the CCR surface impoundments will have adequate hydrologic and hydraulic capacity to prevent such failures as overtopping and excessive internal seepage and erosion. Spillways must be designed to withstand discharge from the inflow design flood without losing their structural form and leading to discharge issues, such as erosion or overtopping of the embankment. This requirement is covered in more detail in the hydrologic and hydraulic capacity requirements for CCR surface impoundments section of this rule.

EPA is not requiring a facility to include any demonstration relating to the potential for rapid, or sudden, drawdown loading condition. Rapid or sudden drawdown is a condition in earthen embankments in which the embankment becomes saturated through seepage in an extended high pool elevation in the reservoir. A threat to the embankment emerges when the reservoir pool is drawn down or lowered at a rate significantly higher than the excess poor water pressure within the embankment can diminish. Typically, rapid drawdown scenarios are considered for embankments with reservoirs used for water supply and management, emergency reservoirs, or agricultural supply, in which the reservoir is rapidly discharged from the structure. In these scenarios, a high pool elevation is maintained in the reservoir in storage months. Subsequently, the water supply is drawn on in months where there is a high demand for the reservoir's contents. This drawing down of the pool can affect the structural stability of the unit. However, the management of CCR surface impoundments differs from that of conventional water supply, emergency, and agricultural reservoirs. The only instance of a rapid drawdown of a CCR surface impoundment which EPA has identified is in the event of a massive release of the reservoir of the CCR surface impoundment due to a failure of the dike of the CCR surface impoundment. In this instance, a massive release has occurred or is occurring. A subsequent failure of the upstream or internal embankment due to this rapid drawdown would only precipitate further embankment failure and not any further release of the contents of the impoundment, as the contents of the surface impoundment would have already been released. In these instances, remediation of a failure in a rapidly drawn-down section would be necessary prior to filling of the unit, but is not a concern precipitating a release of impounded contents.

A second consideration regarding rapid drawdown, however, is the rapid drawdown of a water body adjacent to the slope of the CCR surface impoundment which may periodically inundate the slope. Many CCR surface impoundments are located in areas in which the downstream slope of the CCR surface impoundment runs down to a lake, stream, or river. In such instances, rapid drawdown must be considered for the stability of the downstream slope of the embankment in the event of a rapid drawdown in the lake, stream, or river pool elevation or stage. Because the water ponded against the downstream slope of the CCR surface impoundment provides a stabilizing load on the slope of the CCR surface impoundment, the rapid or gradual loss of this stabilizing force must be considered in the analysis of the CCR surface impoundment. The rule, therefore, requires that existing and new CCR surface impoundments and any lateral expansions of such units with a downstream slope that can be inundated by an adjacent water body, such as rivers, streams, or lakes, be constructed with downstream slopes that will maintain structural integrity in events of low pool or rapid drawdown of the adjacent water body. This ensures that the structural integrity of the downstream slope of the CCR surface impoundment will be maintained, even though the conditions of an adjacent surface water body may be outside the owner or operator's control.

ii. Periodic Safety Factor Assessments

As previously discussed, EPA received comment requesting the Agency to supplement the proposed technical criteria to assist owners or operators of CCR surface impoundments in interpreting the factor of safety determination required by proposed § 257.71(d)(12). EPA proposed that facilities compute "a minimum factor of safety for slope stability of the CCR retaining structure(s)," and to provide the methods and calculations used to determine each factor of safety. In reviewing the proposed requirement, the Agency agrees that further elaboration on the requirement is necessary to ensure that engineers can accurately assess a CCR unit's structural stability using factor of safety calculations, and would be valuable to ensure a consistent national standard. EPA has therefore revised the criteria to be consistent with the criteria developed and used to assess these impoundments as part of the Assessment Program.

Accordingly, the final rule requires demonstrations of structural integrity using accepted engineering methodologies under specific loading conditions. Owners or operators must conduct and have certified by a qualified professional engineer, an initial assessment, supported by the appropriate engineering calculations, documenting whether the CCR unit achieves the following minimum factors of safety: (1) The calculated static factor of safety under the long-term, maximum storage pool loading condition, which must equal or exceed 1.50; (2) the calculated static factor of safety under the maximum surcharge pool loading condition, which must equal or exceed 1.40; (3) the calculated seismic factor of safety, which must equal or exceed 1.00; and (4) the calculated liquefaction factor of safety, which must equal or exceed 1.20. In addition to the safety factors specified for existing CCR surface impoundments, new CCR surface impoundments and any lateral expansion must also comply with a fifth safety factor, the calculated static factor of safety under the end-of-construction loading condition, which must equal or exceed 1.30.

The minimum static factors of safety are adopted directly from the USACE's Engineer Manual EM 1110–2–1902 entitled, "Slope Stability." As discussed in more detail in Unit III of this document, EPA relied heavily on this manual and applied these specific factors of safety during its Assessment Program, and it is widely considered the benchmark in the dam engineering community for slope stability and methodology and analysis.

The seismic factor of safety is adopted from review of several dam safety guidance documents, including USACE guidance Engineer Circular 1110–2–6061: Safety of Dams-Policy and Procedures 2204, Engineer Circular

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1110–2–6000: Selection of Design Earthquakes and Associated Ground Motions 2008, and Engineer Circular 1110–2–6001: Dynamic Stability of Embankment Dams 2004. EPA also reviewed MSHA's 2009 Engineering and Design Manual for Coal Refuse Disposal Facilities, in particular Chapter 7, "Seismic Design: Stability and Deformation Analyses." These documents are viewed by ASDSO, FEMA and MSHA as generally accepted guidance on how to conduct seismic stability analyses. EPA chose the factor of safety of 1.00 because the 1.00 quantity represents the condition of the slope in which the strength of resistance to loading is equal to the anticipated loading stress acting upon the embankment, or the value which represents stability under the appropriate loading condition.

The liquefaction factor of safety is adopted from review of several dam safety guidance and liquefaction guidance, including "Soil Liquefaction During Earthquakes," Idriss and Boulanger, Earthquake Engineering Research Institute, 2008,[91] "Geotechnical and Stability Analyses for Ohio Waste Containment Facilities," Ohio EPA, Sept. 14, 2004, Chapter 5,[92] and *Federal Guidelines for Dam Safety: Earthquake Analyses and Design of Dams,* Document 65, FEMA May 2005.[93] EPA also reviewed several technical resources regarding soil liquefaction, including "Ground Motions and Soil Liquefaction During Earthquakes," Seed and Idriss, 1982,[94] "Liquefaction Resistance of Soils: Summary report from the 1996 and 1998 NCEER/NSF Workshops on Evaluation of Liquefaction Resistance of Soils," Youd and Idriss, 2001,[95] and *Seismic Design Guidance for Municipal Solid Waste Landfill Facilities,* US EPA, Office of Research and Development, 1995. EPA chose a liquefaction factor of safety of 1.20, identifying that consideration of liquefaction potential and post-liquefaction residual strength slope stability included several uncertainties in assumptions and analysis which must be accounted for in a factor of safety above unity (*i.e.,* 1.00). FEMA guidance explicitly states that "post-liquefaction factors of safety are generally required to be a minimum of 1.2 to 1.3."

In conjunction with this requirement, EPA continues to require periodic re-assessments of the safety factor calculations, but as discussed, has modified the frequency to be no less than once every five years for all affected CCR units. Periodic reassessments are necessary to account for factors that are subject to change and can adversely affect the structural stability of a CCR unit, *e.g.,* age, use, volume of material contained within, and to reflect the dynamic nature of a CCR surface impoundment and the loads to which the dikes of the CCR surface impoundment may reasonably be expected to become subject to both the requirement to periodically reassess safety factor calculations and the five-year timeframes are consistent with the guidance set forth by other federal agencies in assessing dam safety, including MSHA, FEMA, and the USACE. For example, FEMA's Federal *Guidelines for Dam Safety* explicitly recommends that a dam be formally reassessed at an interval not to exceed every five years, and EPA has adopted this minimum frequency of assessment in this final rule.

(a) General Safety Factor Assessment Considerations

Generally accepted engineering methodologies specify that the determination of the structural stability factors of safety specified above is to be calculated by the qualified professional engineer using conventional analysis procedures or, if necessary, special analysis procedures. Conventional analysis procedures include, but are not limited to, limit equilibrium methods of slope stability analysis, whereas, special analysis procedures include, but are not limited to, finite element methods, finite difference methods, three-dimensional methods, or probabilistic methods. Whichever methodology is used to determine the factors of safety of the CCR surface impoundment, the qualified professional engineer must document the methodology used, as well as the basis for using that methodology, and the analysis must be supported by appropriate engineering calculations.

Limit equilibrium methods compare forces, moments, and stresses which cause instability of the mass of the embankment to those which resist that instability. The principle of the limit equilibrium method is to assume that if the slope under consideration were about to fail, or at the structural limit of failure, then one must determine the resulting shear stresses along the expected failure surface. These determined shear stresses are then compared with the shear strength of the soils along the expected failure surface to determine the factor of safety. Limit equilibrium methods include, but are not limited to, methods of slices. The most commonly applicable method of slices are the ordinary method of slices or Modified Swedish Method, Bishop's Modified Method, force equilibrium methods, Janbu's method, Morgenstern and Price's method, or Spencer's Method.

If conventional analysis procedures yield results that indicate complex failure mechanisms or the need for estimation of displacements, such as the need to determine internal stresses or displacements in an embankment or account for 3-dimensional effects in an embankment, special analysis procedures may be necessary to calculate factors of safety. Special analysis procedures include, but are not limited to: (1) The finite element method; (2) the finite difference method; (3) the three-dimensional limit equilibrium analysis method; or (4) the probabilistic method.[96]

Structural stability factors of safety need to be met in all cross-sections of the CCR surface impoundment since the failure of any cross-section of the CCR surface impoundment can result in the loss of the reservoir and stored CCR material in the CCR surface impoundment. However, it is not necessary to require the facility to fully analyze and calculate factors of safety for all cross sections under the specific loading conditions identified above. Rather, it is sufficient to calculate the factors of safety under both static, seismic, and liquefaction loading conditions only for the critical cross section of the CCR surface impoundment embankment, provided the facility carefully analyzes each cross section to properly identify the critical cross section. EPA has adopted this approach because the critical cross-section(s) represents a "most-severe" case and it is reasonably anticipated that all other cross-sections of the embankment will exceed the calculated factors of safety of the critical cross-section(s). The final rule therefore adopts this approach. The final rule

[91] *https://www.eeri.org/products-page/monographs/soil-liquefaction-during-earthquakes-3/.*

[92] *http://epa.ohio.gov/portals/34/document/guidance/gd_660.pdf.*

[93] *http://www.ferc.gov/industries/hydropower/safety/guidelines/fema-65.pdf.*

[94] Seed, H.B., and Idriss, I.M., 1982, "Ground Motions and Soil Liquefaction During Earthquakes," Monograph No. 5, Earthquake Engineering Research Institute, Berkeley, California, pp. 134.

[95] Youd, T.L., Idriss, I.M., 2001, "Liquefaction Resistance of Soils: Summary report from the 1996 and 1998 NCEER/NSF Workshops on Evaluation of Liquefaction Resistance of Soils." Journal of Geotechnical and Geoenvironmental Engineering, ASCE.

[96] Additional information regarding special analysis methodologies can be found in publications from the U.S. Army Corps of Engineers Engineering Publications or geotechnical journals and scholarly articles.

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defines the critical cross section of the embankment of a CCR surface impoundment to be that which is anticipated to be most susceptible amongst all cross sections of the embankment to structural failure based on several engineering considerations for the given loading condition, such as soil composition of the cross-section, phreatic surface level within the cross section, grade of the upstream and downstream slopes of the cross section, and presence or lack of reinforcing measures in the cross-section as opposed to other cross-sections, such as buttressing or slope protection on the slopes of the cross section. Due to the variance of qualitative and quantitative properties of embankment structural strength, EPA expects that a prudent engineering analysis will need to consider multiple cross sections to ensure proper selection of a critical cross section.

(b) The Calculated Static Factor of Safety Under the Long-Term, Maximum Storage Pool Loading Condition

It is generally accepted practice to analyze the stability of the downstream slope of the dam embankment for steady-state seepage (or steady seepage) conditions with the reservoir at its normal operating pool elevation (usually the spillway crest elevation) since this is the loading condition the embankment will experience most. This condition is called steady seepage with maximum storage pool. The maximum storage pool loading is the maximum water level that can be maintained that will result in the full development of a steady-state seepage condition. Maximum storage pool loading conditions need to be calculated to ensure that the CCR surface impoundment can withstand a maximum expected pool elevation with full development of saturation in the embankment under long-term loading. The final rule requires that the calculated static factor of safety for the critical cross section of the CCR surface impoundment under the long-term maximum storage pool loading condition meet or exceed 1.5. The generally accepted methodology for determining the long-term, maximum storage pool loading condition considers conditions at the CCR surface impoundment that exist for a length of time sufficient for steady-state seepage or hydrostatic conditions to fully develop within the embankment of the CCR unit.[97] The maximum storage pool loading needs to consider a pool elevation in the CCR unit that is equivalent to the lowest elevation of the invert of the spillway, *i.e.*, the lowest overflow point of the perimeter of the embankment. The generally accepted methodology for the calculation of the factors of safety uses shear strengths expressed as effective stress and with pore water pressures that correspond to the long-term condition. Pore-water pressures should be estimated from the most reliable of the following sources: (1) Field measurements of pore pressures in existing slopes; (2) past experience and judgment of the qualified professional engineer; (3) hydrostatic pressure computation for conditions of no flow; or (4) steady-state seepage analysis using flow nets or finite element analyses.

(c) The Calculated Static Factor of Safety Under the Maximum Surcharge Pool Loading Condition

The maximum surcharge pool loading condition is calculated to evaluate the effect of a raised level (*e.g.*, flood surcharge) on the stability of the downstream slope. This ensures that the CCR surface impoundment can withstand a temporary rise in pool elevation above the maximum storage pool elevation for which the CCR surface impoundment may normally be subject under inflow design flood stage, for a short-term until the inflow design flood is passed through the CCR surface impoundment. The final rule requires that the calculated static factor of safety for the critical cross section of the CCR surface impoundment under the long-term maximum surcharge pool loading condition meet or exceed 1.4.

Similar to the long-term, maximum loading condition, a prudent evaluation of the maximum surcharge pool loading condition needs to consider conditions at the CCR unit to exist for a length of time sufficient for steady-state seepage or hydrostatic conditions to fully develop within the embankment of the CCR surface impoundment. The maximum surcharge pool is considered a temporary pool that is higher than the maximum storage pool; the maximum surcharge loading condition should therefore consider a temporary condition in the pool at which the pool exists temporarily above the maximum storage pool elevation in the event of an inflow design flood and spillway discharge condition in the reservoir, *i.e.*, above the lowest invert of the spillway during the anticipated inflow design flood.

(d) The Calculated Seismic Factor of Safety

All CCR surface impoundments, including any lateral expansions that exceed the size threshold must meet a seismic factor of safety equal to or greater than 1.0. EPA has included this requirement because the mechanics and response phenomena of geotechnical structures vary radically under dynamic loading from those under static loading. Consequently, reliance on the factors of safety under static loading is not sufficient to evaluate the structural stability of a CCR surface impoundment. Standard engineering methodology and guidance support EPA's conclusion that adequate seismic analysis of embanked structures is essential to ensure the continued structural stability of a geotechnical structure under dynamic, or seismic, loading is warranted.[98]

As discussed in the section of this preamble addressing the location criteria, all CCR surface impoundments must also be capable of withstanding a design earthquake without damage to the foundation or embankment that would cause a discharge of its contents. To further support the location criteria established in this rule, CCR surface impoundments and any lateral expansion exceeding a specific height and/or volume threshold must be assessed under seismic loading conditions for a seismic loading event with a 2% probability of exceedance in 50 years, equivalent to a return period of approximately 2,500 years, based on the USGS seismic hazard maps for seismic events with this return period for the region where the CCR unit is located. EPA chose the 2% exceedance probability in 50 years event based on its common use in seismic design criteria throughout engineering. See for example, ASCE 7 *Minimum Design Loads for Buildings and Other Structures, International Building Code.* Moreover, USGS seismic hazard maps, dictate that the life of a structure and the realistic probability of event occurrence be considered in the design of lateral force resisting systems for structures. As discussed in the Regulatory Impact Assessment, the expected life of a CCR surface impoundment can exceed 50 years. Consistent with the location criteria for seismic impact zones, EPA adopted 2% as a reasonable probability of occurrence.

Under standard engineering methodologies, seismic analysis includes several procedures to adequately analyze the structural

[97] U.S. Army Corps of Engineers "Slope Stability" manual.

[98] *E.g.*, FEMA's *Federal Guidelines for Dam Safety: Earthquake Analyses and Design of Dams.*

strength of a CCR surface impoundment during dynamic, *i.e.,* seismic, loading. Such analyses would typically need to include the appropriate characterization of ground motions at the site of the CCR surface impoundment for the 2% probability in 50 years seismic event.[99] In addition, the peak ground acceleration (PGA), velocity, and displacement should be selected using historic records, site-specific observations, or magnitude-distance attenuation relations. Additionally, the analysis would need to include an appropriate duration of earthquake, considering accelorograms for the anticipated event. Appropriate elastic response spectra should be selected using engineering methodology for selection, such as the Newmark-Hall Spectrum or other appropriate published spectra, USGS Probabilistic Maps, or site-specific response spectra.

(e) The Calculated Liquefaction Factor of Safety

All CCR surface impoundments, including any lateral expansions that exceed the size threshold and have been determined to contain soils susceptible to liquefaction must meet a liquefaction factor of safety equal to or greater than 1.20. A prudent engineering analysis of structural stability also includes a liquefaction potential analysis and analysis of post-liquefaction static factors of safety. As discussed previously, liquefaction is a phenomenon which typically occurs in loose, saturated or partially-saturated soils in which the effective stress of the soils reduces to zero, corresponding to a total loss of shear strength of the soil. The most common occurrence of liquefaction is in loose soils, typically sands. The liquefaction FOS determination in the final rule is used to determine if a CCR unit would remain stable if the soils of the embankment of the CCR unit were to experience liquefaction. Liquefaction analysis is only necessary in instances where CCR surface impoundments show, through representative soil sampling, construction documentation, or anecdotal evidence from personnel with knowledge of the CCR unit's construction, that soils of the embankment are susceptible to liquefaction.

EPA has included this requirement because the mechanics and response phenomena of geotechnical structures vary radically following induced liquefaction, *i.e.,* post-liquefaction. Similar to the requirement for seismic factors of safety, liquefaction factors of safety are necessary because reliance on static loading is not sufficient to evaluate the structural stability of a CCR surface impoundment. Standard engineering methodology and guidance support EPA's conclusion that adequate liquefaction potential analyses and post-liquefaction residual strength slope stability analyses of embanked structures is essential to ensure the continued structural stability of a geotechnical structure following dynamic loading.

Under standard engineering methodologies, liquefaction potential analysis and post-liquefaction stability analysis includes several procedures to adequately analyze the structural strength of a CCR surface impoundment. Because only certain soils, such as loose sands, are susceptible to liquefaction, the rule requires only embankments constructed of such soils identified through liquefaction potential analysis to meet liquefaction factors of safety. Such liquefaction potential analysis would need to include proper soil characterization of the embankment soils for soil age and origin, fines content and plasticity index, water content, saturation, and maximum current, past, and anticipated future phreatic surface levels within the embankment, foundation, or abutments, location beneath the natural ground surface, and penetration resistance whether through standard penetration testing (SPT) or, ideally, cone penetration testing (CPT). Post-liquefaction stability analysis would need to include detailed characterization of the site conditions, identification of the minimum liquefaction-inducing forces based on soil characterization, determination of seismic effect on liquefied layers of the embankment, and calculation of factors of safety against each liquefied layer of the embankment.

(f) The Calculated Static Factor of Safety Under the End-of-Construction Loading Condition

The End-of-Construction loading condition must be calculated for new CCR surface impoundments to ensure that the CCR surface impoundment can withstand a "first-filling" of the embankment, during which time the embankment first become saturated and is subject to phreatic flow through the cross-section.

Embankments are typically constructed in layers with soils at or above their optimum moisture content that undergo internal consolidation because of the weight of the overlying layers. Embankment layers may become saturated during construction as a result of consolidation of the layers or by rainfall. Because of the low permeability of fine-grained soils of which many embankments are constructed and the relatively short time for construction of the embankment, there can be little drainage of the water from the soil during construction: resulting in the development of significant pore pressures. Soils with above optimum moisture content will develop pore pressures more readily when compacted than soils with moisture contents below optimum. In general, the most severe construction loading condition is at the end of construction.

The final rule requires that the calculated static factor of safety for the critical cross section of the CCR surface impoundment under end of construction loading conditions meet or exceed 1.30. The End-of-Construction loading condition is analyzed for new construction under their initial filling condition, following the completion of construction. Undrained shear strength conditions are typically assumed for the End-of-Construction loading condition. Both the upstream and downstream slopes of the embankment are analyzed for this condition

(g) Failure To Demonstrate Minimum Safety Factors or Failure To Complete a Timely Safety Factor Assessment

As previously discussed, the rule requires an owner or operator to document that the calculated factors of safety for each CCR surface impoundment achieve the minimum safety factors specified in the rule. For any CCR surface impoundment that does not meet these requirements, the owner or operator must either take any engineering measure necessary to ensure that the unit meets the requirements by the rule's deadlines, or cease placement of CCR and non-CCR waste into the unit and initiate closure of such CCR unit as provided in section 257.102 within six months. Similarly, if an owner or operator fails to complete the initial safety factor assessment or any subsequent periodic factor safety assessment by the deadlines established in the rule, the owner or operator must cease placing CCR and non-CCR waste into the unit and initiate closure within six months.

(h) Vertical Expansions of CCR Surface Impoundments and Structural Integrity Criteria

It is not uncommon for the owner or operator to raise the crest of a CCR surface impoundment to accommodate the additional capacity needs of the

[99] FEMA Doc. 65 "Earthquake Analyses and Design of Dams;" *http://www.ferc.gov/industries/hydropower/safety/guidelines/fema-65.pdf.*

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facility. The record documents that CCR surface impoundments are commonly expanded from the original design or as-built construction, through such "vertical expansions," including where a CCR surface impoundment changes from a "small" CCR unit (*i.e.,* below the height and/or volume threshold) to a "large" CCR unit (*i.e.,* exceeding the height and/or volume threshold). In these situations, the owner or operator of the CCR unit becomes subject to additional structural integrity requirements as a result of the vertical expansion. Realizing that these newly created CCR units will require some time to meet the structural integrity requirements, the Agency is allowing one year from the completion of the vertical expansion for the owner or operator to comply with the requirements of §§ 257.73 or 257.74, as applicable.

*F. Operating Criteria—Air Criteria*

EPA proposed to require CCR landfills, CCR surface impoundments and any lateral expansion to control the creation of fugitive dust. Specifically, EPA proposed that facilities must ensure that fugitive dust either not exceed the standard of 35 μg/m$^3$, established as the level of the 24-hour National Ambient Air Quality Standards (NAAQS) for fine particulate matter (PM–2.5), or any alternative standard established pursuant to applicable requirements developed under a State Implementation Plan (SIP) approved or promulgated by the Administrator pursuant to section 110 of the CAA (see 75 FR 55175). Consistent with the numerical standard, EPA proposed to require that CCR units be managed to control the wind dispersal of dust, and that CCR landfills also be required to emplace wet conditioned CCR (*i.e.,* wetting CCR with water to a moisture-content that prevents wind dispersal and facilitates compaction, but does not result in free liquids) into the unit. EPA also required that documentation of the measures taken to comply with the requirements be certified by an independent registered professional engineer. EPA proposed these requirements based on the results of a screening level analysis of the risks posed by fugitive dust from CCR landfills, which showed that without fugitive dust controls, levels at nearby locations could exceed 35 μg/m$^3$, established as the level of the 24-hour PM 2.5 NAAQS for fine particulate. These measures were also intended to reduce the excessive cancer risks associated with the inhalation of hexavalent chromium. This potential risk would apply to over six million people who live within the census population data "zip code tabulation areas" for the 495 rule-affected electric utility plant locations. (See 75 FR 35215.)[100]

As part of the proposal, EPA solicited comments on the following fugitive dust issues: (1) The location of air monitoring stations near CCR landfills or CCR surface impoundments; and (2) information on any techniques, such as wetting, compaction, or daily cover that are or can be employed to reduce exposures to fugitive dust. The Agency received no information from commenters on either of these issues.

The majority of comments received, however, took issue with the proposed technical standard of 35 ug/m$^3$. Commenters argued that, as proposed, the standard would be impossible to implement because the Agency provided no information on particle size, form of the standards, whether an averaging period is available, point of compliance or how one considers upwind sources. More generally, however, commenters argued that the proposed provisions were unnecessary because fugitive dust issues were adequately addressed by existing air rules through the development and implementation of NAAQS, such as $PM_{10}$ and $PM_{2.5}$. These same commenters acknowledged, however, that if the Agency established a criterion to control fugitive dusts, a more appropriate and reasonable standard could be based on best management practices or BMPs. To that end, commenters offered information suggesting that CCR landfills typically used compaction, regular wetting and temporary covers in conjunction with visual air monitoring to effectively control fugitive dust at their facilities, and that these practices were included in facility operating plans.

As discussed in the proposed rule, EPA's decision to address fugitive dust was based on a peer review of the 2010 draft Risk Assessment, 2007 NODA stakeholder comments, photographic documentation of fugitive dust associated with the management of CCR, Agency actions to control fugitive emissions during the clean-up of the December 2008 TVA Kingston spill, and OSHA's Material Safety Data Sheets (now *Safety Data Sheets* (*SDS*)) requirements for coal ash. These lines of evidence have been bolstered since the proposal, by evidence collected during the eight 2010 CCR public hearings, where stakeholders provided extensive feedback about fugitive dust impacts associated with CCR management at facilities adjacent to their residences, and by documented reports on fugitive dust issues provided by citizen groups.[101] The stakeholders called for federal oversight to address those instances where complaints were seemingly ignored by state regulators and/or where state administrative enforcement measures failed to compel the utilities to effectively amend their dust emission control management practices. The Agency followed up on the complaints with state agencies and compiled a preliminary database on documented and alleged fugitive dust damage cases.[102]

In support of this rule, EPA compiled records of over 20 documented fugitive dust cases, in addition to several alleged cases that could not be verified. The documented cases indicate that fugitive dust concerns arise in all phases of the CCR life cycle—from conveyor belt transfer at the coal-fired power plant, through stockpiling and transport for disposal/beneficial use, and up to final disposition. Fugitive dust also is a potential concern associated with both—landfills and surface impoundments. Whereas a nexus between fugitive dust impacts and CCR landfill operations was to be expected, EPA discovered that fugitive dust was also of concern at CCR surface impoundments, either under conditions of windy winter spells affecting CCR exposed above or next to the CCR surface impoundment boundary, or due to the total CCR surface impoundment evaporation in arid areas.

Very few studies have been undertaken to test the health impacts caused by fugitive dust emissions, and of those few, due to inherent limitations, all failed to prove that fugitive dust was the cause of the documented health concerns. For example, in the wake of the January

[100] As evidenced in 42 U.S.C. 6971(f), Congress intended that the Occupational Safety and Health Administration (OSHA) be able to enforce its regulations to protect workers exposed to hazardous waste and that EPA and OSHA would work together to ensure that. EPA is clarifying that it intends that the CCR disposal rule not preempt applicable OSHA standards designed to protect workers exposed to CCRs; thus EPA's final rule on CCR disposal will apply in addition to any applicable OSHA standards. The Agency has added specific regulatory language in this section to address this intent.

[101] For instance, photographic evidence provided by Susan Holmes, the Bokoshe Environmental Cause Group (B.E. Cause), Bokoshe, Oklahoma. See Earthjustice's brief background coverage at: *http://earthjustice.org/blog/2011-april/not-having-fun-in-bokoshe-ok*, and ABC News' *Oklahoma Town Fears Cancer, Asthma May Be Linked to Dump Site,* March 29, 2011: *http://abcnews.go.com/US/oklahoma-town-fears-cancer-asthma-linked-dump-site/story?id=13240312.*

[102] A compilation of damage cases can be found in the docket supporting this rule.

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2005 coal ash pile collapse at the Rostosky Ridge Road, in Allegheny County, Pennsylvania, both the federal and county studies [103] failed to test during this period and missed the narrow exposure window that would have possibly demonstrated a link between the event and the short-term health symptoms (*e.g.,* sore throat, cough, fever, nausea, fatigue, diarrhea, and headaches) contracted by residents who ultimately removed approximately 1,500 tons of fly ash from their properties immediately after the incident without the benefit of any protective respiratory gear. The federal and county studies also found no evidence of long-term arsenic poisoning of the tested individuals. For recurring instances of CCR dispersion in the air at the Indian River Power Plant, Millsboro, Delaware, three consecutive state studies tentatively established other risk factors as the probable cause for a lung cancer cluster in a down-wind location of the presumable source term (CCR fugitive dust blowing of a landfill and stack emissions).[104] Critics claim that these studies used too small of a sample, and were not designed to capture the impact of long-term exposure to pollution.[105]

Nevertheless, in eleven other cases, states adopted measures to address concerns from fugitive dust emissions; these included conducting lung-cancer cluster and other health studies, conducting particle dispersion studies, issuing Notices of Violation and Consent Orders to the responsible facilities, waiving landfill cover exemptions, and requiring dust management plans for newly permitted CCR landfills. In addition, in several instances, citizens filed lawsuits or reached an out-of-court settlement with the primary responsible party; and in one case, OSHA imposed a steep fine on the owners of a facility manufacturing abrasive blasting and roofing materials from slag produced at a nearby coal-fired power plant, for willfully exposing their workers to dangerously high levels of hazardous dust, and for failing to provide adequate breathing protection and training for workers at the facility. According to stakeholder allegations, fugitive dusts generated by these same materials also adversely impacted residents in the facility's immediate vicinity.

As previously stated, many commenters argued that the proposed numeric particulates standard was incompatible with the air quality requirements established under the States' Implementation Plans (SIPs) or with provisions set up by the states in their Title V Clean Air Permits to the power producers. In addition, the commenters argued that the proposed standard lacked technical details to facilitate effective implementation, and that implementation of the standard required specialized equipment and advanced training to carry out a judicious reading and interpretation of opacity, a proxy measure for the level of fugitive dust emissions. In light of these comments, EPA re-evaluated the existing CAA standards applicable to these units; 40 CFR 70.2 identifies fossil-fuel-fired steam electric plants of more than 250 million BTU/hour heat input as potential sources of fugitive dust (PM sources) that must be covered by state permitting, and 40 CFR 70.3 stipulates that fugitive emissions from a part 70 source shall be included in the permit application and the part 70 permit in the same manner as stack emissions, regardless of whether the source category is included in the list of sources contained in the definition of major source. Based on these applicable CAA requirements, the Agency agrees that the adoption of a PM standard under the final rule would entail a potential for duplication or inconsistency with applicable state-established standards in SIP permits.

EPA also acknowledges the challenges involved in measuring the proposed compliance standard. Because fugitive dust is emitted from non-point sources, it cannot be easily measured by conventional methods. Usually, regulations developed by the states to control fugitive dust stipulate that no person or source shall cause or allow, from any activity, any emissions of fugitive particulate matter that are visible to an observer who looks horizontally along the source's property line. A quantitative measurement of fugitive dust levels (EPA's Reference Method 9) would require measuring opacity, which, as the commenters noted, necessitates specialized technical training, trainee certification, and judicious application of instrumentation.

Therefore, rather than requiring a potentially redundant and challenging-to-implement quantitative standard, EPA is substituting a performance standard for fugitive dust control. This standard requires owners or operators of a CCR unit to adopt measures that will effectively minimize CCR from becoming airborne at the facility, including CCR fugitive dust originating from CCR units, CCR piles, roads, and other CCR management activities. The Agency considers this standard to be consistent with the intent of the proposed rule, with the added advantage of allowing facilities the flexibility to determine the appropriate measures to achieve regulatory compliance at their individual site. This standard and the accompanying regulatory requirements supporting its implementation, will achieve the statutory obligation of "*no reasonable probability of adverse effects on human health and the environment.*"

As in the proposal, the Agency is also requiring documentation of the measures taken to comply with the technical standard in a "CCR fugitive dust control plan" (herein referred to as "plan"). Consistent with the proposal, the plan must be certified by a qualified professional engineer and placed in the operating record and on the owner or operators publicly accessible internet site. The plan requires owners or operators to elaborate on the types of activities applicable and appropriate for the conditions at the facility that will be employed to minimize CCR from becoming airborne at the facility. Examples of control measures that may be appropriate include: Locating CCR inside an enclosure or partial enclosure; operating a water spray or fogging system; reducing fall distances at material drop points; using wind barriers, compaction, or vegetative covers; establishing and enforcing reduced vehicle speed limits; paving and sweeping roads; covering trucks transporting CCR; reducing or halting operations during high wind events; or applying a daily cover.

The initial plan must be completed by the effective date of the rule (*i.e.,* within six months of publication). Because this is an initial plan, and because it must be completed within a short timeframe, EPA acknowledges that the facility may only be able to present its initial judgment of the measures that it anticipates are likely to be effective based on the information that is readily available within this six month

[103] (i) *Coal Fly Ash Landslide, Forward Township, Allegheny County, Pennsylvania,* ASTDR Health Consultation June 1, 2006: *http://www.atsdr.cdc.gov/HAC/pha/CoalFlyAshLandslide/CoalFlyAshLandslideHC060106.pdf* (ii) *Results of the Health Investigation Following Fly Ash Contamination in Forward Township, Allegheny County, Pennsylvania,* Allegheny County Health Department, July 2005: *http://www.achd.net/air/pubs/pdf/Forward%20Fly%20Ash%20Study%202005.pdf.*

[104] *Millsboro Inhalation Exposure and Biomonitoring Study.* State of Delaware Department of Natural Resources and Environmental Control, Department of Health and Social Services, Dover (RTI Project 0213061), DE, May 2013: *http://www.dnrec.delaware.gov/Admin/Documents/Millsboro_Inhalation_Exposure_and_Biomonitoring_Study_Final_Repor_05282013.pdf.*

[105] *Critic chides cancer study: Indian River plant results called lame.* Delawareonline, May 28, 2013: *http://www.delawareonline.com/article/20130528/NEWS/305280081/.*

timeframe. EPA anticipates that owners or operators may need to revise the plan as they gain additional information and experience implementing the regulations. In recognition of this, the final rule also requires that the CCR fugitive dust control plan include a description of the procedures the owner or operator will follow to periodically assess the effectiveness of the control plan. Consistent with other plans required in this rule, the owner or operator may amend the written CCR fugitive dust control plan at any time. However, the owner or operator must amend the written plan whenever there is a change in conditions that would substantially affect the written plan in effect, such as the construction and operation of a new CCR unit. The plan and any subsequent amendments must be certified by a qualified professional engineer.

In addition, the Agency is promulgating with a slight modification the requirement for owners and operators of all CCR landfills and any lateral expansion to emplace CCR as conditioned CCR, as well as the definition of conditioned CCR. *Conditioned CCR* has been defined to mean CCR wetted with water to a moisture content that will prevent wind dispersal, but will not result in free liquids, consistent with the definition in the proposed rule. In response to several commenters' requests, and upon further evaluation the Agency is allowing that in lieu of water, CCR conditioning may be accomplished with an appropriate chemical dust suppression agent.[106] As with other requirements of this rule, in order to ensure that the provisions of the fugitive dust criteria are maintained throughout the operating life of the CCR unit, the Agency is requiring that the owner or operator prepare an annual CCR fugitive dust control report, describing the actions taken to control CCR fugitive dust, a record of all citizen complaints, and a summary of any corrective measures taken. The first annual report must be completed no later than 14 months after placing the initial CCR fugitive dust control plan in the facility's operating record. The owner or operator has completed the annual CCR fugitive dust control report when the plan has been placed in the facility's operating record.

The general public, as well as the Agency, is highly concerned with potential risks associated with CCR fugitive dusts. This was readily apparent during the public hearings and from the many comments received on this issue. The Agency continues to receive information regarding this human health and environmental concern. While the subtitle D provisions of this rule lack permitting oversight mechanisms to control fugitive dust from CCR units, it is clear to the Agency that additional substantive actions was needed to facilitate citizen suit enforcement of this criteria. Consequently, the Agency are adding a specific requirement to the CCR fugitive dust control plan to require owners and operators of all CCR units to develop and implement formal procedures to log citizen complaints involving CCR fugitive dust events. These complaints must, then, be included as part of the annual CCR fugitive dust control report. This report must be placed in the operating record and on the owner or operator's publicly accessible internet site. Promulgation of these measures will subject the owner or operator of the CCR disposal facility to public and state scrutiny, and create an incentive for the owner or operator of the CCR disposal facility to improve compliance with the fugitive dust control requirements.

### *G. Operating Criteria—Run-On and Run-Off Controls for CCR Landfills*

EPA's proposal required owners or operators of CCR landfills and all lateral expansions to design, construct and maintain a run-on control system to prevent flow onto the active portion of these units during the peak discharge from a 24-hour, 25-year storm. As described in the proposed rule, run-on controls are designed to prevent erosion, which may damage the physical structure of the landfill, prevent the surface discharge of CCR in solution or suspension; and to minimize the downward percolation of run-on through wastes, creating leachate. Similarly, EPA proposed run-off controls in order to collect and control, at a minimum, the water volume resulting from a 24-hour, 25-year storm. This standard was proposed in order to protect surface waters from contamination. Under the existing 40 CFR part 257 requirements, to which CCR units are currently subject, run-off must not cause a discharge of pollutants into waters of the United States that is in violation of the National Pollutant Discharge Elimination System (NPDES) under section 402 of the Clean Water Act. EPA did not propose to revise the existing requirement, but merely incorporated it for ease of the regulated community.

The Agency proposed the 24-hour period because it was a timeframe that included storms of high intensity with short duration and storms of low intensity with long duration. EPA believed that this was a widely used standard that had been incorporated into the hazardous waste landfills and MSW landfills regulatory requirements. At the time, EPA had no information that warranted a more restrictive standard for CCR landfills. EPA received no significant comment on the proposed requirements, and for the most part, is adopting the proposed requirements without revision. However, in an effort to clarify and provide more direction to the owner or operator and the certifying qualified professional engineer, the Agency has added additional regulatory language that more specifically describes the technical criteria established under this section of the rule.

The run-on and run-off controls of the final rule require that the owner or operator prepare the initial run-on and run-off control system plan within 18 months of publication of the rule. Run-on and run-off control system plan reporting may require design, construction, and post-construction implementation. In instances where run-on and run-off capacity is insufficient, installing additional capacity may involve construction of diversion structures such as swales or ditches. Many of these efforts may require several months of design and construction, compounded by the fact that much of the work cannot be completed in cold-weather or heavy-rain seasons.

#### 1. Run-On and Run-Off Controls for CCR Landfills and All Lateral Expansions[107]

All CCR landfills and all lateral expansions must be designed, constructed, operated, and maintained with a run-on control system to prevent flow onto the active portion of the CCR unit from the peak discharge from a 24-hour, 25-year storm and a run-off control system to collect and control at

[106] Spray-on adhesives, surfactants, aqueous foamers, humectants (calcium, magnesium, ad sodium chloride and their mixtures), and polymer solutions and emulsions. See, for instance "The Role of Chemicals in Controlling Coal Dust Emissions" Benetech, Inc. available at *http://pdf.ebooks6.com/download.php?id=139860* or Peterson, Edwin. "An Aid to Fugitive Materials Control in Coal Ash Applications" presented at the World of Coal Ash (WOCA) conference—May 9–12, 2011 in Denver, Colorado.

[107] In the proposed rule under the RCRA subtitle D option, EPA jointly proposed run-on and run-off requirements for CCR landfills and CCR surface impoundments under proposed § 257.81. In this final rule, EPA has modified the "run-on and run-off" requirements and is providing separate requirements for CCR landfills and CCR surface impoundments. CCR surface impoundments are now subject to the hydrologic and hydraulic capacity requirements at § 257.82. This new section of the rule more appropriately addresses flow management issues at CCR surface impoundments.

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least the volume of water resulting from a 24-hour, 25-year storm from the active portion of the CCR unit.[108]

Consistent with the proposal, the rule requires the owner or operator of a CCR landfill or lateral expansion to prepare an initial run-on and run-off control system plan for the CCR unit. For existing CCR landfills, the plan must be prepared by the owner or operator no later than one year from the effective date of the rule. For new CCR landfills and any lateral expansion of a CCR landfill, the plan must be prepared no later than the date of initial placement of CCR in the landfill or lateral expansion. The plan must document how the run-on and run-off control systems have been designed and constructed to meet the requirements of rule and must be supported by appropriate engineering calculations. The run-on and run-off control system plan must be certified by a qualified professional engineer and is considered prepared when the owner or operator has placed the plan in the facility's operating record.

The rule also provides for the owner or operator to amend the plan at any time (*e.g.,* prior to receipt of CCR in the CCR unit, during the operating life of the CCR unit, during closure of the CCR unit, or following closure of the CCR unit) provided the revised plan is placed in the facility's operating record. The owner or operator must, however revise the plan whenever there is a change in the conditions that would substantially affect the written plan in effect (*e.g.,* closure of an existing portion or cell of the CCR landfill, resulting in a possible change in the size of the "active portion" of the CCR landfill).

In addition, consistent with other provisions in this rule, the Agency is requiring that the run-on and run-off control system plan be reviewed, and where necessary, revised or updated at least every five years. The Agency is specifying this periodic review in order to address factors having the potential to influence the run-on and run-off control system. Among other things, CCR landfills can be subject to build-out, operational changes, and surface cover changes, all of which have the potential to significantly alter run-on and run-off flows to and from the active portion of the CCR landfill. Changes in storm intensity and duration, as well as upstream catchment area characteristics, can alter flows that may significantly affect a previously adequate run-on and run-off control system. A mandated five year review of a control system plan is consistent with accepted good engineering practices and protocols for proper maintenance of operational systems supporting the overall performance of a CCR landfill. It is also consistent with the proposed requirement that an owner or operator "maintain" the run-on and run-off control system. EPA interprets this to require the owner or operator to ensure that the run-on and run-off control system is kept in a condition that meets the requirements of the rule, *i.e.,* that the run-on and run-off control system both prevents flow onto the active portion of the unit during the peak discharge from a 24-hour, 25-year storm and collects and controls at least the water volume resulting from a 24-hour, 25-year storm event for the duration of the CCR landfill's operational life. A requirement to conduct a review of the control plan at least once every five years merely provides an explicit mechanism to ensure this occurs in a manner that facilitates citizen and state oversight.

The date of preparing the initial plan is the basis for establishing the deadline to complete the first subsequent plan; *i.e.,* the subsequent plan must be completed within five years of the prior plan. The owner or operator may complete any required plan prior to the required deadline and must place the completed plan into the facility's operating record within the five year timeframe. A qualified professional engineer must certify that the run-on and run-off control system plan, including any subsequent amendments, meets the run-on and run-off control system requirements of this final rule.

a. Run-On Control

Consistent with the proposal, EPA is defining *run-on* to mean any liquid that drains over land onto any part of a CCR landfill or any lateral expansion of a CCR landfill. In surface water hydrology, run-on is a quantity of surface run-off, or excess rain, snowmelt, or other sources of water, which flows from an upstream catchment area onto a specific downstream location. This rule requires that the CCR landfill be designed, constructed, operated, and maintained to prevent flow onto the active portion of the CCR landfill during the peak discharge from a 24-hour, 25-year storm. EPA has adopted this requirement to minimize the amount of surface water entering the CCR landfill and to minimize disruption of the CCR landfills operation due to storm water inflow. Uncontrolled or undesirable storm water run-on may have significant impacts on the stability of the slopes of a CCR landfill and continued safe operation of the CCR landfill, due to such phenomena as erosion and infiltration.

b. Run-Off Control

EPA has adopted the definition of run-off from the proposal without revision. *Run-off* means any liquid that drains over land from any part of the CCR landfill. Effectively, run-off is the portion of rainwater, snowmelt, or other liquid which does not undergo abstraction, such as infiltration, and travels overland. Typically, run-off is the product of the inability of water to infiltrate into soil due to saturation or infiltration rate capacity being exceeded. The rule requires that the CCR landfill be designed, constructed, operated, and maintained to collect and control at least the water volume resulting from a 24-hour, 25-year storm. The owner or operator must design, construct, operate, and maintain the CCR landfill in such a way that any run-off generated from at least a 24-hour, 25-year storm must be collected through hydraulic structures, such as drainage ditches, toe drains, swales, or other means, and controlled so as to not adversely affect the condition of the CCR landfill. EPA has promulgated these requirements to minimize the detention time of run-off on the CCR landfill and minimize infiltration into the CCR landfill, to dissipate storm water run-off velocity, and to minimize erosion of CCR landfill slopes. An additional concern with run-off from CCR landfills is the water quality of the run-off, which may collect suspended solids from the landfill slopes. EPA acknowledges that the run-off requirements will also minimize the amount of run-off related pollution generated by the landfill run-off.

c. Run-On and Run-Off Control System Plan

The owner or operator of any CCR landfill must prepare an initial run-on and run-off control system plan documenting, with supporting engineering calculations, how the control systems have been designed and constructed to meet the requirements of the rule. This has been adopted without revision from the proposal. In most cases, EPA expects this documentation will include in addition to the supporting engineering calculations, references and drawings regarding the

[108] Under existing part 257 requirements, to which CCR units are currently subject, runoff must not cause a discharge of pollutants into waters of the United States that is in violation of the National Pollutant Discharge Elimination System (NPDES) under section 402 of the Clean Water Act (40 CFR 257.3–3). EPA did not propose to revise this requirement but is merely incorporating it here for ease of the regulated community.

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identification of the 24-hour, 25-year storm for the location of the CCR landfill, a characterization of the rainfall abstractions, including but not limited to depression storage and infiltration, the selection and basis of an appropriate run-off model, the selection and basis of an appropriate run-on or run-off routing model, and the selection and design of an appropriate run-on and run-off management system (*e.g.,* swales, ditches, retention or detention ponds). Consideration of the above factors would generally constitute a comprehensive review of the hydraulic and hydrologic processes associated with the design of a run-on and run-off control system plan. EPA recognizes that over time, any number of factors, *e.g.,* expansion of the facility, could affect a change in the run-on and run-off control system plan. Consequently in the final rule EPA is providing for flexibility in this area by stating that the plan can be amended by the owner or operator at any time during the life of the CCR landfill, provided the amendments are placed in the operating record and on the facility's publicly accessible Internet site.

*H. Operating Criteria—Hydrologic and Hydraulic Capacity Requirements for CCR Surface Impoundments*

As discussed in the previous section, EPA proposed to require owners or operators of CCR landfills to design, construct, operate, and maintain: (1) A run-on control system to prevent flow onto the active portion of the unit during the peak discharge from a 24-hour, 25-year storm; and (2) a run-off control system to collect and control, at a minimum, the water volume resulting from the same 24-hour, 25-year storm. EPA also proposed to apply these same run-on and run-off requirements to all CCR surface impoundments and lateral expansions.

Commenters overwhelmingly disagreed with EPA's decision to apply the same run-on and run-off requirements to both CCR landfills and CCR surface impoundments, arguing that a "control system to prevent flow onto the active portion of the surface impoundment" was at odds with a commonly employed practice of using CCR surface impoundments to manage incoming storm water and other inflow. While some commenters reasoned that preventing run-on may be appropriate for CCR landfills and CCR surface impoundments surrounded by above-ground dikes, the proposed requirement was entirely inappropriate for units specifically designed to retain storm water from an adjoining watershed or to operate as part of a facility's overall storm water management system. Numerous commenters suggested that instead of the run-on prevention provision for CCR surface impoundments, EPA adopt a requirement specifying that CCR surface impoundments be designed to accommodate "peak discharge events." Other commenters argued that storm water run-on controls were only appropriate during and after the closure of CCR surface impoundments; while still other commenters suggested that EPA remove entirely the run-on and run-off requirements because CCR surface impoundments were typically designed to impound and discharge storm water flow far in excess of a 25-year/24-hour storm event.

In evaluating the arguments against the requirements to prevent flow onto the CCR surface impoundment, the Agency was strongly influenced by guidance developed by FEMA for selecting and accommodating hydraulic and hydrologic inflow and outflow as well as the application of this guidance to the CCR surface impoundments evaluated as part of EPA's Assessment Program.[109] A review of FEMA guidance confirmed commenters' contentions that managing flow both to and from dams and impoundments was a widely used practice, and a preferable management strategy for accommodating storm water flows. This was further confirmed by observations made during EPA's Assessment Program; EPA frequently observed units designed to detain or retain storm water inflows of an upstream catchment area to manage CCR, and/or to receive storm water inflow as part of the facility's overall storm water management system. Moreover, EPA relied on the same FEMA guidance to assess the adequacy of the hydrologic and hydraulic capacity of the CCR surface impoundments. In conducting these assessments, EPA considered a number of factors including operating freeboard, catchment area, hydrologic structures' inflow and outflow ratings, design precipitation event, spillway presence and capacity, and unit operating procedures to make this determination. The adequacy of the capacity was determined using FEMA guidance for selecting and accommodating inflow design floods (IDF) for dams. (Note: The use of the terminology related to "inflow design flood" for CCR surface impoundments rather than "run-on" and "run-off" is more directly applicable to the hydraulic and hydrologic capacity of CCR surface impoundments to adequately manage both the inflow and outflow from a design flood.)

During its assessment effort, EPA also found that, contrary to commenter's arguments CCR surface impoundments were often not designed to address floods in excess of a 24-hour, 25-year storm event. Rather many CCR surface impoundments were deficient in their hydrologic and hydraulic capacity requirements due to factors such as lack of operating freeboard, misunderstanding of the actual contributory area, lack of documentation, undersized decant structures, undersized spillways, and lack of spillways.

EPA also disagrees with the comment asserting that storm water controls are only appropriate during and after closure of CCR surface impoundments. Hydrologic and hydraulic capacity, as determined by an effective design flood control system, is an essential element of the overall structural integrity and safety of a CCR surface impoundment. CCR surface impoundments are subject to any number of stresses throughout their operational life; one of the most common causes of a dike or embankment failure being the inability of the CCR unit to adequately pass or manage flood flows resultant from direct or indirect precipitation. These failures can occur at any point in the CCR unit's life, not solely during and after closure, and are usually due to inadequate hydrologic and hydraulic capacity, leading to internal erosion due to seepage and piping, erosion of spillways, overtopping erosion, and overstressing of the embankment. Furthermore, according to the U.S. Bureau of Reclamation, a common dam failure mode is due to overtopping, accounting for 30% of the failures in the U.S. over the last 75 years.[110] Overtopping is the direct result of lack of adequate hydrologic and hydraulic capacity of a dam or surface impoundment. Therefore, EPA is not modifying the regulation as suggested by the commenter.

In light of comments received, observations made during EPA's Assessment Program, and guidance developed by FEMA, EPA has concluded that it was inappropriate to propose to prohibit all run-on discharge or inflow from storm water to CCR surface impoundments. EPA has also

[109] EPA referred to FEMA's "Federal Guidelines for Dam Safety: Selecting and Accommodating Inflow Design Floods for Dams" in evaluating the adequacy of the CCR surface impoundment's hydrologic and hydraulic capacity during its assessment effort.

[110] *http://www.usbr.gov/ssle/damsafety/Risk/BestPractices/16-FloodOvertoppingPP20121126.pdf.*

concluded that run-on and run-off criteria are inappropriate for CCR surface impoundments, and that a more appropriate standard involves determining the hydrologic and hydraulic capacity of a unit, measured by its inflow design flood or IDF. Therefore, EPA is amending the proposed run-on and run-off requirements for CCR surface impoundments to require owners or operators of all CCR surface impoundments to design, construct, operate, and maintain hydraulic and hydrologic capacity to adequately manage flow both into and from a CCR surface impoundment during and after the peak discharge resulting from the inflow design flood, based on the Hazard Potential Classification of the CCR surface impoundment.

The final rule requires the preparation of the initial inflow design flood control system plan within 18 months of publication of the final rule. In many cases, inflow design flood control system plan reporting may require design, construction, and post-construction implementation in order to provide sufficient hydrologic and hydraulic (H/H) capacity for the CCR unit. In instances where H/H capacity is insufficient, installing additional capacity may involve spillway construction or decant structure construction or installation. Many of these efforts may require several months of design and construction, compounded by the fact that much of the work cannot be completed in cold-weather or heavy-rain seasons.

1. Inflow Design Flood Controls for CCR Surface Impoundments and All Expansions

The Agency has concluded that the proposed requirement preventing run-on to a CCR surface impoundment was both impractical and unwarranted and could possibly disrupt effective storm water management systems operating at CCR facilities. Therefore, consistent with FEMA guidance, the Agency is modifying this requirement to require an owner or operator of an existing or new CCR surface impoundment or any lateral expansion to design, construct, operate, and maintain H/H capacity of CCR surface impoundments to: (1) Adequately manage flow into the CCR surface impoundment during and following the peak discharge of the inflow design flood; and (2) adequately manage flow from the CCR unit to collect and control the peak discharge resulting from the inflow design flood. The inflow design flood is based on the hazard potential classification of the unit as required by § 257.73 and § 257.74 of this rule.[111] The inflow design floods for specific hazard potential classifications are as follows: (1) The probable maximum flood (PMF) for high hazard potential CCR surface impoundments; (2) the 1000-year flood for significant hazard potential CCR surface impoundments; (3) the 100-year flood for low hazard potential CCR surface impoundments; and (4) the 25-year flood for incised CCR surface impoundments.[112]

EPA has based this revised requirement on the FEMA's guidance entitled, "Selecting and Accommodating Inflow Design Floods for Dams," which represents current and accepted practices in dam engineering and provides a consistent and uniform standard that has been adopted throughout dam engineering.

Incised CCR surface impoundments, as defined in this rule, are also required to meet inflow design flood requirements.[113] While incised units do not pose the same potential for release as a diked unit, *i.e.,* breach of dike and release of CCR, overtopping of an incised unit does represent a potential environmental hazard warranting control. EPA acknowledges, however, that overtopping of an incised unit would result in a release of CCR material through a surcharge flow, *i.e.,* flow of a temporary stage overtopping the "crest" of the incised CCR surface impoundment, and would not precipitate the degradation of a dike and potential subsequent breach of a dike and massive release of contents of the CCR surface impoundment. To reflect the lower risks associated with such releases, and because incised CCR surface impoundments are not required to determine their hazard potential classification, the Agency is requiring that incised CCR surface impoundments only must accommodate a 25-year flood for the hydrologic and hydraulic capacity requirements of the rule. EPA chose the 25-year flood for incised CCR surface impoundments to maintain consistency with the proposed rule, which required that all units accommodate a 25-year storm event. As part of these requirements, EPA is also finalizing a definition of *inflow design flood* and *flood hydrograph. Inflow design flood* has been defined to mean the flood hydrograph that is used to design or modify the CCR surface impoundment and its appurtenant works, and *flood hydrograph* has been defined to mean the temporal distribution of inflow into a CCR surface impoundment.

2. Inflow Design Flood Control Systems

Controlling the inflow and outflow of the CCR surface impoundment reduces the risks of hydrologic failure, which include overtopping erosion, internal excessive seepage and piping, erosion of spillways, and overstressing of the structural components of the CCR surface impoundment. The CCR surface impoundment's H/H capacity is to be designed based on the unit's hazard potential classification as determined by a qualified professional engineer. To meet the performance standard in the rule, the CCR surface impoundment must be designed to have adequate H/H capacity to ensure that rainfall and watershed characteristics have been accounted for, the hydraulic ratings of all intake structures are adequate and free of obstruction, operating freeboard is adequate, all spillways and decant structures have adequate capacity, and all downstream hydraulic structures have adequate capacity. While not required, an antecedent flood study may be necessary to characterize the condition of the CCR surface impoundment under normal operating conditions.

EPA recognizes that in many impoundment configurations, an inflow design flood may be limited to the direct precipitation that falls within the perimeter of the CCR surface impoundment during a storm event, due to the lack of storm water inflow routing from adjacent catchment areas. Other CCR surface impoundments may have storm water or other hydrologic contributions from various catchment areas or other sources. The final rule's hydraulic and hydrologic capacity standards require all CCR surface impoundments to have adequate hydraulic and hydrologic capacity to accommodate all contributory inflow to CCR surface impoundments, regardless of the inflow's origin.

The hydraulic and hydrologic capacity requirements will minimize the potential for overtopping to occur from normal or abnormal operations, overfilling, wind and wave action, rainfall, and run-on, and will ensure that the unit is operated with appropriate consideration of these potentially adverse conditions. The Agency notes, however, that the operating freeboard of a CCR surface

[111] *Federal Guidelines for Dam Safety: Selecting and Accommodating Inflow Design Floods for Dams.* August 1, 2013. FEMA P–94.

[112] All discharge from the CCR surface impoundment must be handled in accordance with the surface water requirements under § 257.3–3.

[113] *Incised CCR surface impoundment* means a CCR surface impoundment which is constructed by excavating entirely below the natural ground surface, holds an accumulation of CCR entirely below the adjacent natural ground surface, and does not consist of any constructed diked portion.

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impoundment is subject to fluctuations, deviating from original design assumptions and specifications. Additionally, EPA notes that routine maintenance and alterations of hydraulic structures associated with the CCR surface impoundments, *e.g.,* decant structures and spillways, can adversely impact the hydrologic and hydraulic capacity of the CCR surface impoundment. At no point should the inflow design flood exceed the capacity of the CCR surface impoundment, regardless of fluctuations in freeboard, maintenance of hydraulic structures, or other potential obstructions to the hydraulic and hydrologic capacity of the unit. The owner or operator must account for operational changes or diminished capacity in the calculation of hydraulic and hydrologic capacity of the CCR unit.

3. Inflow Design Flood Control System Plan

The owner or operator of an existing CCR surface impoundment must prepare an initial inflow design flood control system plan to document that the design and construction of the system will achieve the rule's performance standards no later than 18 months after the publication of this rule in the **Federal Register**. New CCR surface impoundments or lateral expansions of CCR surface impoundments must prepare an initial inflow design flood control system plan no later than the date of initial receipt of CCR in the unit. The owner or operator must obtain a certification from a qualified professional engineer that the plan meets all applicable requirements of the rule for inflow design flood control system plans. The plan must also be supported by appropriate engineering calculations. This documentation should also include references, and drawings regarding the identification of the design storm for the catchment area affecting the CCR surface impoundment and the CCR surface impoundment itself, a characterization of the rainfall abstractions, including but not limited to depression storage and infiltration in the upstream catchment area affecting the CCR surface impoundment. In addition, EPA expects supporting documentation to address the selection and basis of an appropriate run-off model and an appropriate run-on or run-off routing model; the identification and characterization of any intake or decant structures of the CCR surface impoundment; an appropriate characterization of the spillway(s) of the CCR surface impoundment and their capacity; and characterization of downstream hydraulic structures which ultimately receive the discharge from the CCR surface impoundment. Finally, the owner or operator must comply with the recordkeeping, notification and internet requirements specified in the rule for the plan.

The owner or operator may amend the written inflow design flood control system plan at any time prior to receipt of CCR in the CCR unit, during the operating life of the CCR unit, during closure of the CCR unit, or following closure of the CCR unit provided the revised plan is placed in the facility's operating record. The owner or operator must amend the written inflow design flood control system plan whenever there is a change in the conditions that would substantially affect the written plan in effect. The owner or operator of the CCR surface impoundment must also periodically update the inflow design flood control system plan. The owner or operator must review or update an existing plan at a frequency no less than every five years. Changes in storm characteristics (*e.g.,* intensity and duration) and upstream catchment area characteristics, hazard potential classifications, as well as build-out, operational changes, and diminishing available capacity, all have the potential to influence inflow design flood volumes and therefore the effectiveness of the existing inflow design flood control systems. A periodic review of the plan to address these and other factors is necessary to ensure that the hydrologic and hydraulic capacity of the unit is maintained over time. An update of the inflow design flood control system plan should document any modifications pertinent to the inflow design flood control system.

The owner or operator may amend the written inflow design flood control system plan at any time and must place the revised plan in the facility's operating record. However, the owner or operator must amend the written inflow design flood control system plan whenever there is a change in the conditions that would substantially affect the written plan in effect. The owner or operator of the CCR unit must also review and, where necessary, update an inflow design flood control system plan every five years. As part of this review, the owner or operator must obtain certification from a qualified professional engineer must certify that the inflow design flood control system plan, and any subsequent amendments continues to meet the requirements of the rule. The date of completion of the initial plan is the basis for establishing the deadline to complete the first subsequent plan. The owner or operator may complete any required plan prior to the required deadline, and must place the completed plan into the facility's operating record within a reasonable amount of time.

*I. Operating Criteria—Inspection Requirements for CCR Surface Impoundments*

EPA proposed structural stability requirements for CCR surface impoundments based on the long-standing MSHA requirements, with only minor modifications. These structural stability requirements were covered in various sections of the proposed rule (see specifically proposed §§ 257.71, 257.72, 257.83, and 257.84). Section 257.83 addressed requirements for periodic inspections of CCR surface impoundments. In proposing these requirements, the Agency concluded that periodic inspections were critical to ensure that any problems relating to structural stability are quickly identified and remedied to prevent catastrophic releases, such as occurred at Martins Creek, Pennsylvania and TVA's Kingston, Tennessee facility. The proposed rule required owners or operators to conduct: (1) Weekly inspections to detect potentially hazardous conditions or structural weakness; and (2) annual inspections to assure that the design, operation, and maintenance of the surface impoundment was in accordance with generally accepted engineering standards. EPA proposed that weekly inspections be conducted by a person qualified to recognize specific signs of structural instability and other hazardous conditions by visual observation and, if applicable, to monitor instrumentation. The proposed rule also required annual inspection reports from an independent registered professional engineer, certifying that the design, operation, and maintenance of the CCR surface impoundment was in accordance with generally accepted engineering standards. Consistent with the annual inspection requirements, EPA, as part of its recordkeeping requirements also proposed that owners or operators of CCR surface impoundments annually document and report on, among other things: (1) Changes in the geometry of the impounding structure; (2) location and type of instrumentation monitoring the unit; (3) the minimum, maximum and present depth and elevation of the impounded water, sediment or slurry for the reporting period; and (4) storage capacity of the impounding structure (see 75 FR at 35246).

The annual inspection provisions also required that if a potentially hazardous

condition developed, the owner or operator must immediately take several actions: Eliminate the potentially hazardous condition; notify potentially affected persons and state and local first responders; notify and prepare to evacuate, if necessary, all personnel from the property who may be affected by the potentially hazardous condition(s); and direct a qualified person to monitor all instruments and examine the structure at least once every eight hours, or more often as required by an authorized representative of the state. Finally, the proposed rule required that inspection and monitoring reports be maintained in the facility operating record and placed on the facility's publicly accessible Internet site as well as promptly reporting the results of the inspection or monitoring to the state.

EPA specifically requested comment on whether to cover all CCR impoundments for stability (including the inspection requirements), regardless of height and storage volume, whether to use the cut-offs in the MSHA regulations, or whether other regulations, approaches, or size cut-offs should be used. The Agency further requested commenters who believed that other regulations or size cut-offs should be used (and not the size cut-offs established in the MSHA regulations) to provide the basis and technical support for their position. (75 FR 35176, 35223). In response to EPA's general solicitation for alternative size cut-offs, the Agency received little response. However, many commenters questioned EPA's decision to require inspections for all CCR surface impoundments, given that the other structural stability requirements were triggered only if the CCR unit exceeded the proposed size threshold (consistent with MSHA requirements). Commenters argued that there was no basis to require inspections of all CCR surface impoundments given that units below the specified size threshold had a much lower risk of catastrophic failure. A more limited requirement the commenter's argued, was supported by MSHA's decision to regulate only those "larger" sized units. Other commenters argued that inspection timeframes should take into account site specific conditions at the site and be based on the recommendations of an independent registered professional engineer. Commenters reasoned that while, in theory, a short inspection interval (*i.e.,* a weekly inspection) should increase the chances of finding an adverse condition, the judgment of a qualified professional engineer to establish the frequency and focus, as well as the purpose of the dam safety inspection was a far more effective method for detecting and preventing the development of a potentially adverse situation. Still other commenters questioned the overall value of a weekly inspection if, as proposed, no documentation of the results was required.

In reviewing the proposed regulatory language, it appears an error was made. Although the preamble generally stated that the proposed regulatory requirements addressing stability (which included inspections) applied only to those CCR surface impoundments exceeding the specified size threshold established by the MSHA regulations, the regulatory text required inspections for all CCR units. The final rule requires weekly general inspections and monthly instrumentation inspections to be conducted for all CCR surface impoundments. Periodic inspections of all CCR units are a necessary practice to ensure that the overall structural integrity of the CCR unit is maintained and that actual and potential structural weaknesses and other hazardous conditions are quickly identified and remediated throughout the active life of the unit. All CCR surface impoundments pose some risk of release—whether from a catastrophic failure or from a more limited structural failure, such as occurred at Duke Energy's Dan River plant. Periodic inspections are a generally accepted, prudent engineering practice that will significantly reduce the risks of such failures; during the Assessment Program, EPA discovered that many facilities routinely conduct some sort of periodic inspection and monitoring, although the frequency varied widely between facilities. The final rule merely codifies this practice, by establishing a consistent minimum timeframe. EPA is therefore requiring that all CCR surface impoundments be inspected by a qualified person both weekly (for visual signs of a potentially adverse condition) and monthly (for instrumentation monitoring). Consistent with the proposed rule, EPA is also requiring annual inspections for all CCR surface impoundments that exceed the specified size threshold of: (1) A height of five feet and a storage capacity of 20 acre-feet; or (2) a height of 20 feet, must also be inspected no less than annually by a qualified professional engineer. These inspection requirements are generally being promulgated as proposed, with minor technical clarifications.

The final inspection requirements have been drawn heavily from guidelines established by FEMA for dam safety, under which maintaining structural integrity involves continuous evaluation of the unit, based on periodic inspections. To be most effective, FEMA suggests, and EPA concurs, that inspections be varied with respect to both the time interval between inspections and the level of detail of the inspection. FEMA guidance, in part, suggests that inspections can be categorized as either: Visual observations to identify abnormal conditions (*i.e.,* informal inspections); field inspections by a professional engineer (*i.e.,* intermediate inspections); and a technical review to determine if the unit meets current and accepted design criteria and practices (*i.e.,* formal inspection).[114] In general, FEMA recommends that inspections focusing on visual observations should be conducted often (*e.g.,* weekly) while more substantive technical evaluation should be conducted every year to every five years depending on the engineering analyses required. (See also the preamble discussion on the requirements specified in §§ 257.73 and 257.74 of this rule, in particular the discussion addressing the five year time interval for structural stability and factor of safety reassessments.)

For the reasons discussed above, EPA has concluded, consistent with FEMA guidelines, that routine inspections of all CCR units are necessary to ensure that the units are safely operated and that issues that could disrupt the safety and continuing operation of these units are promptly identified and remediated. Accordingly, the final rule requires both weekly inspections and monthly instrumentation inspections to be conducted at all CCR surface impoundments to confirm that they are operating safely. These inspections must be conducted by a qualified person trained to recognize specific signs of structural instability and other hazardous conditions by visual observation and if, applicable monitor instrumentation. EPA is also retaining the annual inspection requirement for CCR surface impoundments exceeding the specified size threshold established in this rule. This inspection must be conducted and certified by a qualified professional engineer. Units exceeding this size threshold pose a higher degree of risk of release of CCR to the environment than other types of CCR surface impoundments (*e.g.,* incised or "small" CCR units) and as such warrant additional regulatory control and oversight.

[114] See "*Federal Guidelines for Dam Safety*" Federal Emergency Management Agency. (Reprinted April 2004).

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The final rule requires that both weekly inspections of the CCR unit and monthly monitoring of CCR unit instrumentation be initiated within 6 months of the publication of the rule.

Within nine months of the publication of the rule, the owner or operator must complete the initial annual inspection of the CCR unit. Initial annual inspection requires the retaining of a professional engineer along with the familiarization of the engineer with the facility and CCR units. Additionally, the annual inspection should not be conducted unless weekly inspection and monthly instrumentation monitoring has been initiated and established in order to generate a body of information for the professional engineer to consider. Furthermore, in some cold-weather regions of the United States, weather may inhibit adequate inspection of CCR units, whether through snow or ice cover. EPA is establishing a timeframe of nine months after the publication of the rule so as to allow for adequate weather conditions for inspection.

1. Surface Impoundment Inspection Requirements

a. Weekly Inspections

As presented in the proposed rule and finalized here, this rule requires all CCR surface impoundments to be examined by a qualified person at least once every seven days for any appearance of actual or potential structural weakness or other conditions that are disrupting or that have the potential to disrupt the operation or safety of the CCR unit. The results of the inspection by a qualified person must be recorded in the facility's operating record.

Weekly inspections are intended to detect, as early as practicable, signs of distress in a CCR surface impoundment that may result in larger, more severe conditions. They are also designed to identify potential issues with hydraulic structures that may affect the structural safety of the CCR surface impoundment and impact the hydraulic and hydrologic capacity of the CCR surface impoundment. The early detection of signs of structural weaknesses is an essential preventative measure which helps to impede structural failure. The required weekly inspections are designed to identify such signs of structural weakness before they develop into larger, debilitating concerns in the structural stability of the dike.

Appearances of structural weakness may include, but are not limited to: (1) Excessive, turbid, or sediment-laden seepage; (2) signs of piping and other internal erosion; (3) transverse, longitudinal, and desiccation cracking; (4) slides, bulges, boils, sloughs, scarps, sinkholes, or depressions: (5) Abnormally high or low pool levels; (6) animal burrows; (7) excessive or lacking vegetative cover; (8) slope erosion; and (9) debris.

In addition, EPA is also adopting a new provision that requires the qualified person to inspect the discharge of all outlets of hydraulic structures which pass underneath the base of the CCR surface impoundment or through the dike of the CCR unit for abnormal discoloration, flow, or discharge of debris or sediment. The requirement is being added to aid in the identification of any internal or sub-surface issues which cannot be reasonably identified in a routine visual inspection. Abnormal discharges from hydraulic structures are often an indication of potential issues with the sub-surface or internal integrity of the structure. Hydraulic structures, particularly corrugated metal pipe, are subject to deterioration and corrosion over time and, as deterioration proceeds, the hydraulic structure becomes more susceptible to collapse, translation, or malfunction. Issues with hydraulic structures within the dike may exacerbate structural or operational issues with the CCR surface impoundment due to the significant internal deterioration of the dike via the hydraulic structure. As an example, on February 2, 2014, Duke Energy's Dan River Fossil Plant experienced a structural collapse of a corrugated metal storm water discharge pipe which passed underneath the interior of a CCR surface impoundment. The subsequent collapse of the base of the CCR surface impoundment led to a massive release of CCR to the environment. Additionally, the adjacent dike of the CCR surface impoundment was severely damaged due to the erosion of the upstream slope.

Further, an owner or operator may want to consider inspections outside of the weekly, seven-day schedule if an unanticipated event, such as a flood, earthquake, or vandalism occurs on the site. While rare in occurrence, these events may increase the chances that a potential structural stability issue has arisen. Prudent CCR management practices dictate that a visual assessment is warranted after such events. For example, after a large flood (considered a flood with a return period of equal or greater frequency of ten years) there is potential for damage, including structural damage to the CCR surface impoundment, caused by increased reservoir levels that inundate areas infrequently inundated. The slopes of the dike should be inspected to ensure that no significant erosion has occurred due to the flood, or that any large debris or sediment has been deposited on the dike. An inspection should also be conducted following an earthquake where earthquake damage is observed or can be reasonably expected, where ground motion is felt at the CCR surface impoundment or in nearby locations, or following established magnitude-epicenter distance relationships.[115]

b. Monthly Instrumentation Inspection

In a departure from the proposed rule, EPA is requiring the monitoring of all instrumentation supporting the operation of the CCR unit to be conducted by a qualified person no less than once per month. This is a change from the proposal which required instrumentation to be monitored no less than every seven days.

Many commenters argued that requiring inspections every seven days was excessive, and that, based on FEMA guidelines for dam safety, a more reasonable timeframe would be once per month for CCR surface impoundments with a hazard potential rating of "high" and quarterly for those CCR surface impoundments with a hazard potential rating of "significant." In considering these comments, the Agency was influenced by a number of factors including the FEMA guidelines suggested by the commenters. Also weighing heavily in EPA's decision were the observations made as part of the Assessment Program, which revealed that many CCR units are equipped with only "basic" measuring devices such as piezometers and pool elevation and freeboard instrumentation and not the more sophisticated (*i.e.*, sensitive) measuring devices for measuring pressure, seepage, internal movement, slope movement; and vibration. These findings strongly suggested to the Agency that, given the status of current instrumentation employed at CCR facilities, weekly monitoring would be excessive, impractical, and—of greatest significance—unlikely to indicate any measurable changes in structural stability in such a short timeframe. EPA, therefore, agrees that a monthly timeframe is a more appropriate interval for detecting discernible or significant changes in the operation of the CCR

[115] The U.S. Army Corps of Engineers have developed useful criteria for post-earthquake inspections, specifically their published magnitude-epicenter distance criteria in Table 11.1 of "Safety of Dams—Policy and Procedures," ER 1110–2–1156, 31 March 2014.[115] The criteria stipulate when the dam (or in the case of this rule, CCR surface impoundment) should be inspected.

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unit. EPA has not, however, differentiated between high, significant, and low hazard potential CCR surface impoundments in the requirement that instrumentation be monitored monthly, as commenters suggested. Through the assessment effort, EPA identified that typically low hazard potential CCR surface impoundments were monitored less frequently than high- or significant hazard potential CCR surface impoundments by the owner or operator. Additionally, these low hazard potential CCR surface impoundments less commonly were equipped with sophisticated monitoring instrumentation, including remote monitoring instrumentation which would allow the owner or operator to monitor the unit from a remote location. Based on these observations, along with the limited burden that instrumentation monitoring places on the owner or operator, the rule requires all CCR surface impoundments with instrumentation to be monitored monthly.

c. Annual Inspections

The rule requires owners or operators of any CCR surface impoundments exceeding the MSHA size threshold (*i.e.,* a height of five feet or more and a storage volume of 20 acre-feet or more; or a height of 20 feet or more) to conduct annual inspections of the CCR unit throughout its operating life. These annual inspections are focused primarily on the structural stability of the CCR surface impoundment and must ensure that the operation and maintenance of the CCR surface impoundment is in accordance with recognized and generally accepted good engineering standards. Inspections must be conducted and certified by a qualified professional engineer.[116] Incised CCR surface impoundments, as defined in § 257.53 are not subject to the annual inspection requirements. Incised units present lower risks of structural failure, and so weekly inspections are sufficient to address any risks associated with these CCR units.

Annual inspections of any CCR surface impoundment must include, at a minimum: (1) A review of all previously generated information regarding the status and condition of the CCR unit, including, but not limited to, all operating records and publicly accessible internet site entries, design and construction drawings and other documentation; (2) a thorough visual inspection to identify indications of distress, unusual or adverse behavior, or malfunction of the CCR unit and appurtenant structures; and (3) a thorough visual inspection of hydraulic structures underlying the base of the CCR unit and passing through the dike of the CCR unit for structural integrity and continued safe and reliable operation. Additionally, following each inspection, the qualified professional engineer must prepare an inspection report which documents the following: (1) Any changes in geometry of the impounding structure since the previous annual inspection; (2) the location and type of existing instrumentation and the maximum recorded readings of each instrument since the previous annual inspection; (3) the approximate minimum, maximum, and present depth and elevation of the impounded water and CCR since the previous annual inspection; (4) the storage capacity of the impounding structure at the time of inspection; (5) the approximate volume of the impounded water and CCR at the time of the inspection; and (6) any appearances of an actual or potential structural weakness of the CCR unit, in addition to any existing conditions that are disrupting or have the potential to disrupt the operation and safety of the CCR unit and appurtenant structures; and (7) any other change(s) which may have affected the stability or operation of the impounding structure since the previous annual inspection.

This last set of requirements was originally presented in § 257.84 of the proposed rule (*i.e.,* recordkeeping requirements), however, the Agency has moved these requirements to the annual inspection section of the rule because (1) these requirements apply only to CCR surface impoundments exceeding the specified size threshold, rather than all CCR surface impoundments, as proposed; (2) must be reported annually; and (3) are more appropriately housed in the inspection section.

The owner or operator of existing CCR surface impoundments must ensure that the initial annual inspection by a qualified professional engineer is completed and documented with a report no later than nine months after the publication of the rule. EPA established this timeframe for completing an initial annual inspection based on its experience with the Assessment Program. In an effort similar to conducting an initial annual inspection, the following tasks were generally completed within three months: Retaining the services of a qualified professional engineer, developing a scope of work, reviewing existing documentation on the CCR unit, conducting a thorough field inspection, and completing an inspection report. Owners and operators of new CCR surface impoundment must commence annual inspections no later than one year from the initial placement of CCR into the new unit. An annual inspection is not required in any calendar year in which the five year structural stability reassessment is also required to be completed. (See §§ 257.73 and 257.74.) The report which the qualified professional engineer has certified must be placed in the facility's operating record and placed on the facility's publicly accessible internet site. An annual inspection is considered complete when the inspection report has been placed in the facility's operating record. Finally, if a deficiency is identified during an inspection, the owner or operator must take immediate measures to remedy the structural weakness or disrupting condition as soon as feasible.

*J. Operating Criteria—Inspections for CCR Landfills*

Under 40 CFR part 258, EPA does not require specific inspection requirements for MSWLFs. Rather, EPA relies on states to establish their own inspection criteria and frequency of inspections to ensure protection of human health and the environment. It is the Agency's understanding that many states require owners or operators of MSWLFs to conduct either daily, weekly, quarterly and annual inspections of these units to ensure that the design, construction, operation, and maintenance complies with all requirements. In addition, based on a review of selected state regulations most states conduct state inspections of operating landfills no less than annually.

Under the proposed subtitle D option, EPA did not propose to require mandatory inspections of new or existing landfills or any lateral expansion. However, under the subtitle C option, EPA proposed to apply the requirements of § 264.303 to permitted CCR landfills. Specifically, these requirements stated that CCR landfills while in operation would be required to be inspected weekly and after storms to detect evidence of any of the following: (1) Deterioration, malfunctions, or improper operation of run-on and run-off control systems; (2) proper functioning of wind dispersal control systems, where present; and (3) the presence of leachate in and proper functioning of the leachate collection and removal system where present. (See proposed § 264.1306, 75 FR 35257).

[116] For purposed of this requirement, qualified means an individual experienced in the operation and maintenance of dams and who has been trained to recognize signs of concern and structural weakness by visual observation, and if applicable, to monitor instrumentation.

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Upon further evaluation, the Agency has decided, consistent with the weekly inspection requirements proposed for CCR landfills under the subtitle C option, as well as many state requirements for MSWLFs, to require all existing and new CCR landfills and any lateral expansion to conduct, at intervals not exceeding seven days, inspections by a qualified person for any appearances of actual or potential structural weakness or any other conditions which are disrupting or have the potential to disrupt the operation or safety of the CCR landfill. In addition, EPA is also requiring inspections by a qualified professional engineer at intervals not exceeding one year to ensure that the design, construction, operation, and maintenance of the CCR landfill is consistent with recognized and generally accepted good engineering standards. This inspection must include a review of all data in the operating record as well as a visual inspection of the unit to identify signs of distress or malfunction that is or potentially could affect the safe operation of the unit. The qualified professional engineer must then also prepare a report to identify and discuss the findings of the inspection as well as a discussion of potential remedies for addressing any deficiencies discovered during the inspection. The Agency has concluded that all CCR landfills should be routinely inspected to ensure that they are operating as designed and are being maintained in compliance with the federal criteria.

The Agency is promulgating these inspection requirements based on: (1) A review of state municipal landfill inspection requirements; and (2) comments from parties that clearly supported inspections of all CCR landfills. The Agency reviewed MSWLF inspection checklists in a selected number of states to assess the scope of these inspections. The Agency also conducted a preliminary review of state MSWLF regulations for New York, Pennsylvania, Ohio, Wisconsin, Illinois, Missouri, North Dakota and California. All of these states require MSWLF owners or operators to conduct a either daily, weekly, monthly, quarterly and annual inspections addressing the following: (1) Proper placement of the waste; (2) slope stability and erosion control; (3) surface water percolation is minimized (*i.e.* reduce ponding); (4) liner systems and leachate collection systems are properly operated and maintained; (5) water quality monitoring systems are maintained and operating; (6) dust is controlled; and (7) a plan is in place to promptly address and correct problems and deficiencies discovered during the inspection. The Agency also noted during its review of state regulations that states reserve the right to inspect landfills at any time and routinely conduct state inspections on a no less than annual basis. CCR landfills present at least the same level of risks as MSWLFs, and while the operations may differ, both operating systems are equally susceptible to malfunction. Weekly inspections of all CCR landfills by a qualified person are therefore equally necessary to ensure that groundwater monitoring, run-on and run-off controls, liner systems, and leachate collection systems are operated and maintained to reduce adverse environmental and human health impacts.

This rule also requires that owners or operators of all existing and new CCR landfills and any lateral expansion conduct an annual inspection, certified by a qualified professional engineer, to assure that these units are designed, constructed, operated, and maintained throughout their operating life to ensure protection of human health and the environment. The Agency finds that annual inspections for these units are justified for a number of reasons. First, CCR landfills are large engineered units that require that a variety of design and operating parameters be assessed to assure that the CCR landfill is operating as designed. Of particular concern to the Agency is the fact that coal ash is a fine grained material that may have the potential to compact and clog leachate collection systems (see: "Operations and Maintenance Guidelines for Coal Ash Landfills" Christopher Hardin, et. al. 2011 World of Coal Ash Conference. May 2011). It is reasonable therefore that the rule requires annual inspections to assure that these liner and leachate systems are assessed to assure that they are performing their functions as designed. Second, a formal annual inspection would review data collected during weekly inspections and determine if any remedial actions are need to address deficiencies. Third, the annual review by a qualified professional engineer ensures that a detailed level of engineering analysis of operating conditions are evaluated which could lead to recommendations to address design or operating issues that need attention.

### *K. Groundwater Monitoring and Corrective Action*

EPA is finalizing groundwater monitoring and corrective action requirements to ensure that groundwater contamination at new and existing CCR units will be detected and cleaned up as necessary to protect human health and the environment. These requirements reflect Congressional intent that protection of groundwater be a prime objective of any new solid waste regulations. As stated in the proposal, EPA's damage cases and risk assessments indicate there is significant potential for CCR landfills and CCR surface impoundments to leach hazardous constituents into groundwater, impair drinking water supplies and cause adverse impacts on human health and the environment. Indeed, groundwater contamination is one of the key environmental and human health risks EPA has identified with CCR landfills and CCR surface impoundments. Groundwater monitoring is a key mechanism for facilities to verify that the existing containment structures, such as liners and leachate collection and removal systems, are functioning as intended. Thus, in order for a CCR landfill or CCR surface impoundment to show no reasonable probability of adverse effects on health or the environment, a system of routine groundwater monitoring to detect any contamination from a CCR unit, and corrective action requirements to address identified contamination, are essential.

EPA proposed to require that a system of monitoring wells be installed at all new and existing CCR units. The regulation would also provide procedures for sampling these wells and methods for statistical analysis of the analytical data derived from the well samples to detect the presence of hazardous constituents released from these CCR units. The Agency proposed a groundwater monitoring program consisting of detection monitoring and assessment monitoring, and a corrective action program. This phased approach to groundwater monitoring and corrective action programs provides for a graduated response over time to the problem of groundwater contamination as the evidence of such contamination increases. This allows for proper consideration of the transport characteristics of CCR constituents in groundwater, while protecting human health and the environment.

EPA largely based these proposed groundwater monitoring requirements on those for MSWLFs in the 40 CFR part 258 criteria, albeit with certain modifications to tailor the requirements to the case at hand. In particular, the possibility that a state may lack a permit program for CCR units made it impossible to include some of the alternatives available in 40 CFR part 258, which establish alternative standards that allow a state, as part of

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its permit program to tailor the default requirements to account for site specific conditions at the individual facility. EPA also sought to tailor the proposed requirements for CCR units, by incorporating certain provisions from the interim status regulations, which operate in the absence of a permit, and by including in several of the proposed requirements, a certification by an independent registered professional engineer that the rule's requirements had been met.

In the proposed rule, the Agency required facilities to install a groundwater monitoring system that met a specified performance standard and that consisted of a minimum of one upgradient and three downgradient wells at all CCR units. EPA acknowledged in the proposal that the design of an appropriate groundwater monitoring system is particularly dependent on site conditions relating to groundwater flow, and on the development of a system that has a sufficient number of wells, installed at appropriate locations and depths, to yield groundwater samples from the uppermost aquifer that represent the quality of background groundwater that has not been affected by contaminants from a CCR unit. EPA's existing requirements under 40 CFR parts 258 and 264 recognize this, and because they operate in a permitting context, these requirements provide more flexibility in establishing groundwater monitoring systems. But because the same guarantee of permit oversight is not available under the criteria developed for the proposal, EPA proposed to establish a minimum requirement based on the part 265 interim status regulations, which are self-implementing. Long experience demonstrates that these monitoring requirements will be protective of a wide variety of conditions and wastes, and that facilities can feasibly implement these requirements. EPA also noted that in many instances a more detailed groundwater monitoring system will need to be in place, and EPA therefore proposed requiring a certification by the independent registered professional engineer that the groundwater monitoring system is designed to detect all significant groundwater contamination.

EPA also proposed to require that owners and operators of CCR units establish consistent sampling and analysis procedures to determine whether a statistically significant increase in the level of a hazardous constituent(s) has occurred, indicating the presence of groundwater contamination.

As noted, EPA proposed a phased approach to monitoring. The first phase is detection monitoring where indicators would be monitored to determine whether groundwater was potentially being contaminated. The parameters EPA proposed to be used as indicators of groundwater contamination were the following: Boron, chloride, conductivity, fluoride, pH, sulfate, sulfide, and total dissolved solids (TDS). In selecting the parameters for detection monitoring, EPA chose constituents that are present in CCR and would rapidly move through the subsurface, and thus provide an early detection of whether contaminants were migrating from the CCR unit. Under the proposed rule, monitoring would be required no less frequently than semiannually.

When a statistically significant increase over background levels is detected for any of these parameters, the proposed rule required the facility to begin an assessment monitoring program to determine if releases of CCR constituents of concern had occurred. The parameters that were proposed for assessment monitoring were aluminum, antimony, arsenic, barium, beryllium, boron, cadmium, chloride, chromium, copper, fluoride, iron, lead, manganese, mercury, molybdenum, pH, selenium, sulphate (sic), sulfide, thallium, and total dissolved solids.

The proposed rule also required that whenever monitoring results indicate a statistically significant level exceeding the groundwater protection standard for any of these parameters, the owner or operator must start the process for cleaning up the contamination, and initiate an assessment of corrective action remedies. The proposed rule required that the assessment of correction action remedies be initiated within 90 days and then completed within 90 days.

EPA proposed that the assessment of corrective measures must consider a number of factors, including the effectiveness, performance, and time needed for the potential remedies. As part of the assessment of corrective measures, the owner or operator was required to identify the source of the release. The owner or operator was also required to gather data on plume definition, fate of the contaminants, stratigraphy and hydraulic properties of the aquifer. The owner or operator also was required to consider whether immediate measures to limit further plume migration or measures to minimize further introduction of contaminants to groundwater would be necessary. EPA also proposed to require the owner or operator to provide notification of the corrective measures assessment to the State Director, place the corrective measures assessment in the operating record and on the owner's or operator's publicly accessible internet site, and discuss the results of the corrective measures assessment in a public meeting with interested and affected parties.

Based on the results of the corrective measures assessment, EPA proposed to require the owner or operator to select a remedy based on a number of factors, including: the long- and short-term effectiveness and protectiveness of the potential remedy, along with the degree of certainty that the remedy will prove successful; the effectiveness of the remedy in controlling the source to reduce further releases; the ease or difficulty of implementing a potential remedy; the degree to which community concerns are addressed by a potential remedy; and potential risks to human health and the environment from exposure to contamination prior to completion of the remedy. The owner or operator was also required to specify as part of the selected remedy a schedule for initiating and completing remedial activities.

Under the proposed rule, implementing the corrective action program required the owner or operator to establish and implement a corrective action groundwater monitoring program; implement the corrective action remedy selected; and take any interim measures necessary to ensure the protection of human health and the environment, all according to the schedule the owner or operator developed during the assessment of corrective measures.

The proposed rule also required that the owner or operator must demonstrate that concentrations of constituents have not exceeded the groundwater protection standards for three consecutive years in order to support a determination that the remedy is complete.

The majority of the commenters supported "appropriate groundwater monitoring standards for CCR waste management units" and the development of such standards under a RCRA subtitle D framework. Comments were received on various parts of the groundwater monitoring scheme laid out in the proposed rule. The majority of comments received requested EPA to provide "more flexibility" to the proposed requirements. Many commenters wanted the states to be more involved with the process and provided comments suggesting that additional "flexibility," such as is provided in the 40 CFR part 258

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regulations for MSWLFs as part of the permitting process, be extended to CCR units. For example, commenters wanted states to have the authority to add or drop monitoring constituents; approve alternative schedules; modify the number of wells needed; allow variances; allow alternatives to the point of compliance specified in the rule; employ alternative methods to detect potential groundwater contamination, such as leak detection systems; allow alternatives to the statistical methods used to determine whether groundwater contamination has occurred; and to replace the qualified professional engineer role in the certification process.

For the final rule, EPA has developed a groundwater monitoring program that is flexible and allows facilities to design a system that accounts for site specific conditions within specific parameters. The final rule establishes an overall performance standard that the system must meet, lays out the minimum requirements of an effective system, and requires the owner or operator to design a system that achieves that overall performance standard based on a full characterization of site conditions.

As described in more detail below, in certain cases, EPA was able to develop performance standards to serve as "more flexible" alternatives to the technical specifications laid out in the proposal. In these instances, the available information allowed the Agency to develop performance standards that were sufficiently objective and determinate that EPA could conclude that the 4004(a) standard would be met nationwide.

However, many of the commenters' requests related to alternatives that would be less stringent than the minimum criteria laid out in the proposal and were based on arguments that state regulators (or facilities) should be allowed to "tailor" those requirements to sites that did not need those particular requirements. As explained at length in the proposal, EPA is concerned that provisions allowing such modifications are particularly susceptible to abuse, since in many cases the provisions could allow substantial cost avoidance. In the absence of a mandated state oversight mechanism to ensure that the suggested modifications are technically appropriate, these kinds of provisions can operate at the expense of protectiveness. In Unit II of this preamble, EPA explains the extent of our authority to establish criteria under RCRA sections 1008(a)(3) and 4004(a), including the implications associated with the lack of any authority to establish a program analogous to part 258, which relies on approved states to implement the federal criteria through a permitting program. As a result of the statutory structure, this rule is self-implementing and is designed to operate to ensure that facilities will manage CCR in a manner that achieves the 4004(a) standard even in the absence of any regulatory entity available to judge the reasonableness of the desired alternatives. While some states currently do have programs for the regulation of CCR, which in some cases may be more stringent than this final rule, the federal program must be defensible on the record in place at the time the final rule is adopted. Based on the current rulemaking record, in most cases EPA lacked the information necessary to defend the commenters' less stringent alternatives (*i.e.,* the commenters' requested "flexibilities") to the minimum technical criteria specified in this rule for these units. Under both the subtitle C and part 258 programs, EPA can rely on subsequent proceedings to develop the information necessary to support such tailoring. This is clearly neither contemplated nor authorized under the regulatory program relevant to this rule.

In addition, given the extremely technical nature of these requirements, EPA remains concerned that such provisions would render the requirements appreciably more difficult for citizens to effectively enforce. Nevertheless, working within these constraints this rule specifically allows the qualified PE to design a system that accounts for site conditions within the parameters of the minimum technical criteria, and EPA has added language to the regulation that expressly clarifies this. Moreover, states that have programs can continue to impose more stringent requirements, and thus can require, for example, additional monitoring wells, monitoring of additional aquifers, and inclusion of additional parameters to the detection monitoring list or the assessment monitoring list. The following discussion addresses in more detail the technical requirements under groundwater monitoring and corrective action in the final rule.

1. Applicability

Consistent with the provisions in the proposed rule, the final rule requires a system of monitoring wells to be installed at all CCR landfills, CCR surface impoundments and lateral expansions. Existing CCR units must install the groundwater monitoring system, develop their groundwater sampling and analysis procedures, develop background levels for appendix III and appendix IV constituents, and begin detection monitoring (§ 257.90 through § 257.94) within two years of the effective date of this rule. The proposed rule required that existing CCR units comply with the groundwater monitoring requirements within one year of the effective date. EPA proposed one year believing that it would be feasible for facilities to install the necessary systems. EPA also believed that a one year timeframe would ensure that existing CCR disposal facilities begin monitoring groundwater as soon as possible, so that releases from existing CCR units are detected and addressed. Comments received on this issue argued that the one-year timeframe was not sufficient to complete a hydrogeologic study and develop a monitoring plan. Several commenters requesting more time mentioned staffing shortages and limited contractor and lab resources. One state, referencing its experience relating to development and implementation of groundwater monitoring systems, said that a one year timeframe to investigate, design and submit and obtain approval for the installation of an effective groundwater monitoring system was unreasonable. Most commenters thought that a timeframe of two years was reasonable. After review of the comments received on this issue and careful reexamination of the actual requirements in the final rule, EPA agrees that a one-year timeframe is not feasible, and has decided to extend the timeframes for completing installation of the system, including background monitoring, to two years. As important as it is to begin detecting and addressing releases to groundwater, it is equally important that these complex systems be designed and installed correctly. That generally entails a number of activities, many of which must occur sequentially, including: determining the uppermost aquifer, deciding whether to install a single or multi-unit monitoring system, collecting and evaluating hydrogeological information that can be used to model the site, characterizing the site geology, characterizing the groundwater flow beneath the site, determining the flow direction and hydraulic gradient, establishing horizontal and vertical flow direction, determining hydraulic conductivity, determining groundwater flow rate, determining the monitoring wells placement, selecting the drilling method, designing the monitoring wells, developing sampling and analysis procedures, choosing a statistical method for evaluating the data and

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beginning detection monitoring. We also recognize that in some states, the state may require the owner or operator to receive state approval before they can install a groundwater monitoring system. Two years is a more reasonable timeframe in which to carry out these activities. New CCR landfills, new CCR surface impoundments and any lateral expansion must comply with these same requirements (§§ 257.90 through 257.94) before any CCR can be placed in the CCR unit.

Consistent with the proposal, the final rule also requires that the owner or operator of the CCR facility annually certify that each CCR unit is in compliance with the groundwater monitoring and corrective action provisions and provide a copy of this certification to the State Director. Because this is a self-implementing rule that relies on citizen enforcement, it is important for the owner or operator of the facility to periodically document that they are in compliance with the existing groundwater monitoring requirements, and an annual certification is the easiest and most effective way to achieve this. While the groundwater monitoring data will be made available on the owner or operator's publicly accessible Web site and in the operating record of the facility, the analysis of these data is complicated and requires a certain level of scientific expertise to analyze the data correctly. As such, a document that serves as both an interpretative record of scientific analysis and regulatory compliance is critically important to the successful implementation of a self-implementing rule that is to be enforced exclusively by citizens and the states. For similar reasons, the certification must also be placed in the operating record, provided to the State Director, and posted on the owner or operator's publicly accessible Web site.

The groundwater monitoring requirements must be met throughout the active life of the CCR unit, as well as during the closure and post-closure care period.

EPA has added a new provision to § 257.90 to address the corrective action requirements that apply when CCR have been released into the environment, such as from the kind of structural failure that occurred with TVA's Kingston Fossil Fuel plant release, or from the kind of release that occurred in North Carolina at the Dan River. EPA inadvertently drafted the corrective action requirements in the proposed rule to apply exclusively upon detection of groundwater contamination caused by a leaking unit. However, there is no reason to establish different corrective action provisions for conducting clean-up operations for different kinds of releases; the same general process is applicable to all kinds of releases.

The new provision requires that in the event of a release from a CCR unit, the owner or operator must immediately take all necessary measures to control the source(s) of releases so as to reduce or eliminate, to the maximum extent practicable, further releases of contaminants into the environment. The owner or operator of the CCR unit is also required to comply with all of the relevant corrective action requirements in §§ 257.96, 257.97, and 257.98.

2. Groundwater Monitoring System Requirements

EPA received comments that supported establishing more prescriptive requirements for the design of the groundwater monitoring system. For example, one commenter argued that three downgradient wells are insufficient to ensure detection of leakage from the very large disposal units typically used for CCR; due to uncertainty in flow directions, the perimeter of the CCR unit must be monitored on its cross-gradient, as well as downgradient sides. The commenter suggested that the minimum number of non-background monitoring wells should instead be three, plus one for every 500 feet of downgradient and cross-gradient perimeter of the CCR unit (*i.e.,* if the perimeter length adds up to 1200 feet, the minimum number of wells would be five), and that wells should be spaced no more than 500 feet apart along the downgradient and cross-gradient perimeter. EPA also received many comments arguing that the minimum requirements were overly prescriptive, and that the final rule should instead allow a professional engineer or hydrologist to design "an alternative, but equally effective, groundwater monitoring program." The majority of comments on groundwater monitoring systems requested that EPA not promulgate requirements that would be incompatible with state requirements.

The final rule provisions are fundamentally the same as those in the proposal, although EPA has also added language to the regulations to better clarify how the requirements in the various sections collectively operate. The final rule establishes a general performance standard that all groundwater monitoring systems must meet: All groundwater monitoring systems must consist of a sufficient number of appropriately located wells (at least one upgradient and three downgradient wells) in order to yield groundwater samples from the uppermost aquifer that represent the quality of background groundwater and the quality of groundwater passing the waste boundary. This is the same performance standard included in the proposed rule. The objective of a groundwater monitoring system is to intercept groundwater to determine whether the groundwater has been contaminated by the CCR unit. Early contaminant detection is important to allow sufficient time for corrective measures to be developed and implemented before sensitive receptors are significantly affected. To accomplish this, the rule requires that wells be located to sample groundwater from the uppermost aquifer at the waste boundary. These requirements have been adopted without fundamental change from the proposal.

Because hydrogeologic conditions vary so widely from one site to another, the rule does not prescribe the exact number, location and depth of monitoring wells needed to achieve the general performance standard. Rather, the rule requires the owner or operator to install a minimum of one upgradient and three downgradient wells, and any additional monitoring wells necessary to achieve the general performance standard of accurately representing the quality of the background groundwater and the groundwater passing the waste boundary. The number, spacing, and depths of the monitoring wells must be determined based on a thorough characterization of the site, including a number of specifically identified factors relating to the hydrogeology of the site (*e.g.,* aquifer thickness, groundwater flow rates and direction). Further, any owner or operator who determines that the specified minimum number of wells is adequate must provide a factual justification for that decision. Factors that may substantiate a reduced density of groundwater monitoring wells includes simple geology (*i.e.,* horizontal, thick, homogenous strata that are continuous across site, with no fractures, faults, folds, or solution channels), a flat and constant hydraulic gradient, uniform hydraulic conductivity, low seepage velocity, and high dispersivity potential.

In essence, the rule establishes a presumption that the minimum of one upgradient and three downgradient wells is not sufficient, and requires the owner or operator to rebut that presumption in order to install only this minimum. This is fundamentally consistent with the proposed rule, which required the installation of a system that would achieve the general performance standard, as well as the

"minimum" of one upgradient and three downgradient wells. The final regulation merely makes more explicit that both of these requirements must be met.

EPA considered establishing a more prescriptive set of requirements, including a specified number, location, and design of monitoring wells, but because of the highly site specific nature of developing an adequate groundwater monitoring system, determined that it lacked sufficient information to be able to design a single groundwater monitoring system that would be nationally protective at all sites. A properly designed system must account for many variables, most of which are highly dependent on the individual characteristics of the unit and the facility site. Consequently, the final rule leaves the exact system design to be determined by those at the site, including a qualified professional engineer, who can tailor the design of the system to the unit and site conditions.

Nevertheless, EPA is confident that the parameters laid out in the regulation will ensure that the design of groundwater monitoring systems at CCR facilities will be protective. As a practical matter, EPA expects that there will be few cases, if any, where four wells will be sufficient, given that this requirement was originally developed for hazardous waste management units that are typically much smaller than CCR units. As mentioned above, a small unit with simple geology, a flat and constant hydraulic gradient, uniform hydraulic conductivity, low seepage velocity, and high dispersivity potential would be the type of unit for which the minimum number of wells could be sufficient to meet the overall performance standard. Although EPA is finalizing a requirement for one upgradient and three downgradient wells as a regulatory minimum, the Agency expects large CCR units to have many more wells because most CCR sites have hydrologic settings that are too complex for the regulatory minimum to be adequate. Facilities with large CCR units could have as many as thirty or more downgradient wells. This is because the placement and spacing of detection monitoring wells along the downgradient perimeter of the CCR unit must be based on the abundance, extent, and physical/chemical characteristics of the potential contaminant pathways. All potential pathways need to be monitored.

Therefore, even though EPA is not requiring a specific number of wells, the Agency is confident that the combination of the requirements will ensure that protective groundwater monitoring systems will be installed. The owner or operator is required to install a sufficient number of wells to meet the performance standard in § 257.91(a)(1) and (2), provide a justification if they determine the required minimum is adequate, and have a qualified professional engineer certify that their groundwater monitoring system has been designed and constructed to ensure that the groundwater monitoring will meet this performance standard—*i.e.,* accurately represent the quality of groundwater that has not been affected by leakage from any CCR unit—that is, groundwater from background wells and the quality of groundwater passing the waste boundary.

The final rule establishes certain parameters regarding the location of the wells. Upgradient background wells must be located beyond the upgradient extent of potential contamination. However, groundwater quality in areas where the geology is complex can be difficult to characterize. If the facility is new, groundwater samples collected from both upgradient and downgradient locations prior to waste disposal can be used to establish background water quality. Downgradient wells to monitor for any contaminants leaking into the groundwater must be located at the hydraulically downgradient perimeter (*i.e.,* the edge) of the CCR unit or at the closest practical distance from this location.

Determining background groundwater quality by sampling wells that are not hydraulically upgradient may be necessary where hydrogeologic conditions do not allow the owner or operator to determine which wells are hydraulically upgradient (*e.g.,* floodplains, where nearby surface water can influence groundwater). In such cases, the rule allows the owner or operator to establish groundwater quality at existing units by locating wells that are not upgradient under certain conditions (§ 257.91(a)(1)). This provision may be used when hydrogeologic conditions do not allow the owner or operator to determine which wells are hydraulically upgradient and when sampling at other wells will provide data establishing background groundwater quality that is equally or more representative than that provided by upgradient wells. These conditions could include one or more of the following:

- The facility is located above an aquifer in which groundwater flow directions change seasonally.
- The facility is located near production wells that influence the direction of groundwater flow.
- Upgradient groundwater quality is affected by a source of contamination other than the CCR unit.
- The proposed or existing CCR unit overlies a groundwater divide or local source of recharge.
- Geologic units present at downgradient locations are absent at upgradient locations.
- Karst terrain or fault zones modify flow.
- Nearby surface water (*e.g.,* rivers) influences groundwater flow directions.

Additionally, there is nothing in the rule that would prevent the owner or operator from monitoring multiple aquifers in addition to the uppermost significant aquifer. Certain site conditions warrant more extensive monitoring requirements, as discussed in "Technical Manual Solid Waste Disposal Facility Criteria", EPA530–R–93–017, USEPA, November, 1993, Chapter 5, Subpart E, Ground-Water Monitoring and Corrective Action.

Each CCR unit must have its own groundwater monitoring system, unless the owner or operator chooses to install a multiunit groundwater monitoring system. The final rule specifies that if a multiunit system is installed, it must be based on the consideration of several factors, including the number, spacing, and orientation of the CCR units, the hydrogeologic setting, the site history and the engineering design of the CCR units. A multiunit groundwater monitoring system must be equally capable of detecting background and groundwater contamination at the waste boundary as an individual monitoring system. This documentation must be certified by a qualified professional engineer. Whether a single or multi-unit system has been installed, the monitoring wells must be cased in a manner maintaining the integrity of the borehole and must be maintained so as to meet design specifications. Both of these provisions have been adopted from the proposal without revision.

3. Sampling and Analysis Requirements

EPA received comment on several aspects of its proposed requirements for conducting groundwater sampling and analyses. Specifically mentioned here, commenters raised concern about the number of samples required to establish background concentrations and about the statistical test methodologies specified in the proposal. As discussed below, EPA has modified the rule to account for the issues raised by these commenters. The sampling and analysis requirements in the final rule have

otherwise been adopted from the proposed rule with only minor clarifications.

The rule provides procedures for sampling monitoring wells and methods for the statistical analysis of groundwater monitoring of appendix III (detection monitoring) and appendix IV (assessment monitoring) constituents that may be released from CCR units. The sampling and analysis program must include procedures and documentation for sample collection (including the frequency, water level measurements, well purging, field analyses, and sample withdrawal and collection); sample preservation and handling (including sample containers, sample preservation, sample storage and shipment); chain of custody control; analytical procedures (appropriate methods can be found in "*Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,*" SW–846 (USEPA, 1986), *http://www.epa.gov/waste/hazard/testmethods/sw846/online/index.htm*); and quality assurance/quality control. More information and guidance can be found in "*Technical Manual Solid Waste Disposal Facility Criteria,*" EPA530–R–93–017, USEPA, November, 1993, Chapter 5, Subpart E, Ground-Water Monitoring and Corrective Action, as well as the "*Unified Guidance Document: Statistical Analysis of Groundwater Monitoring Data at RCRA Facilities,*" March 2009, EPA 530/R–09–007.

Similar to the approach used in designing a groundwater a number of system, the final rule adopts a combination of a general performance standard for groundwater sampling and analytical methods, along with particular technical specifications that must be met. The general performance standard requires that the method used must accurately measure hazardous constituents and other monitoring parameters. In addition, the rule specifies that groundwater elevations must be measured in each monitoring well immediately prior to sampling. Also, the rate and direction of the groundwater flow in the uppermost aquifer must be determined each time groundwater is sampled. Further, the rule specifies that the background groundwater quality must be established at a hydraulically upgradient well for each of the monitoring parameters or constituents required by the applicable groundwater monitoring program, except as provided in § 257.91. The number of samples collected to establish groundwater quality data must be consistent with the appropriate statistical procedures determined for the specific statistical method chosen. The sampling must also be conducted to account for both seasonal and spatial variability in groundwater quality.

To establish background levels, the proposed rule required that "a minimum of four independent samples from each background and downgradient well must be collected and analyzed . . ." 75 FR 35247–35248 (proposed §§ 257.93(f) and 257.94(b)). This is the same sampling protocol that EPA adopted for both the subtitle C and part 258 groundwater monitoring requirements.

EPA received comments criticizing this sampling protocol. Several commenters stated that more than the required four samples were needed in order to adequately represent background water quality and reduce the number of false negatives. For example, one commenter argued that EPA should require a minimum of one year of monthly monitoring of background concentrations to characterize fluctuations in parameters that will be evaluated statistically. The commenter claimed that this would also help to ensure that quarterly monitoring events are properly timed. Another comment stated that more data points and time were needed to ensure statistical confidence in the data. By contrast, another commenter objected to the requirement to obtain four independent samples, arguing that this requirement was unnecessary and should be deleted. The commenter argued that this requirement was inconsistent with EPA's Unified Guidance (EPA, 2009) for Statistical Analysis of Groundwater Monitoring Data at RCRA Facilities, which specifies that replicate samples (*i.e.,* multiple samples from the same location during a given sampling event) should typically be limited to the collection of two samples from the same location, rather than four. Another commenter requested clarification on the number of samples required when establishing background levels that would serve as the point of comparison in determining whether a statistically significant increase over background levels had occurred.

In response to these comments, EPA reviewed the available information to determine whether revisions to the proposed requirements were warranted.

More recent information developed since the promulgation of the subtitle C and part 258 groundwater monitoring requirements indicates that statisticians now generally consider sample sizes of four or less to be insufficient for good statistical analysis because the observations are too few to adequately characterize the parameters of the population. Tests utilizing a small background sample size have low statistical performance in terms of power and per-test false positive rates. In 2009, EPA issued a guidance document that accounts for more recent scientific developments, "*Unified Guidance Document: Statistical Analysis of Groundwater Monitoring Data at RCRA Facilities,*" March 2009, EPA 530/R–09–007. This guidance recommends a minimum of eight to ten independent background observations be collected before performing the first statistical test. Sample sets of 20 are considered optimal.

RCRA regulations are predicated on having appropriate and representative background measurements. Samples should be tested against data which best represent current uncontaminated conditions. In addition, as discussed further in Unit VI.K.5 below, the detection of a statistically significant increase over background concentrations of the constituents of concern will have serious implications for unlined surface impoundments, as these units will be required to close whenever the facility makes such a finding. EPA is also cognizant of the significant differences between the subtitle C and part 258 regulations and the final regulations being promulgated for CCR units. Both the subtitle C and the part 258 MSWLF requirements are implemented under permit programs, under which regulatory authorities are specifically authorized to establish more stringent requirements to account for scientific advances (among other things). EPA expects that current permits generally specify a greater number of samples than the minimum laid out in the regulations (*i.e.,* more than four) to determine background concentrations. And because of this it is less critical that those regulations (subtitle C and part 258) reflect the most current science. By contrast, as previously discussed, the provisions adopted under this rule are self-implementing, and will only be updated through a subsequent rulemaking. Accordingly, the Agency agrees with the comments that four samples would be insufficient and has amended the rule to require the owner or operator to collect, at a minimum, eight statistically independent and identically distributed (spatially invariant) samples from each well for each monitoring parameter. Although still a small sample size by statistical standards, eight independent observations allows for minimally acceptable estimates of variability and evaluation of trend and goodness-of fit. While more samples, including a full

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year of background monitoring, would be scientifically ideal, the Agency selected eight samples by balancing the minimum number needed to ensure the scientific accuracy of the results against the need to expedite initiating the groundwater monitoring process of detecting exceedances, along with any necessary corrective action at these facilities.

Background sampling (*i.e.,* the requirement to collect eight statistically independent samples from each well) must be completed for all appendix III and IV constituents by the end of the 24 month period to begin implementation of the groundwater monitoring program.

EPA has also revised the regulatory text relating to the number of samples that must be collected during subsequent sampling events after background concentrations have been established to clarify how the various provisions collectively operate. Consistent with the proposal, the final rule requires the owner or operator to collect and analyze the number of samples from each well necessary to be consistent with the statistical test selected under § 257.93(e) and with the unique characteristics of the site, but at minimum, to collect at least one sample from each background and downgradient well. In cases where the groundwater is "well-behaved" one sample from each compliance well could be all that the owner or operator would need to conduct the necessary comparisons. But if statistical assumptions are not met (*e.g.,* the observations are not statistically independent or background well data show trends) a comparison based on a single observation will not yield a significant result, and will likely result in a false positive. Further, detection monitoring tests, such as Student's t-test, look at the difference between the sample means (*e.g.,* upgradient vs downgradient) to determine when an observed difference should be considered more than a chance fluctuation. Every t-test assumes that the observations that make up each data group meet the requirements of statistical independence and stationarity. Therefore, the larger the sample size the more significant the result. In other words, a facility can choose to use only one observation (a group size of one), but the chances are good that the result derived would be non-significant, since there are many reasons sample means can vary. Consequently, it is likely to be in the facility's best interest to take more samples than the minimum, particularly in the early stages of monitoring. As monitoring continues, each successive sample will be added to the sampling data base, which will increase the confidence in the statistical analyses performed. Additional guidance on sample size can be found in the "*Unified Guidance Document: Statistical Analysis of Groundwater Monitoring Data at RCRA Facilities,*" March 2009, EPA 530/R–09–007.

The requirements for applying statistical procedures in the rule are the same as those included in the proposed rule, which were based on the statistical procedures used in the MSWLF regulations. The rule requires the owner or operator to select from among the listed statistical procedures based on a determination that the test is appropriate for evaluating groundwater at that site. The statistical method chosen must be appropriate for the distribution of chemical parameters or hazardous constituents. The rule has been revised to include the clarification that normal distributions of data values shall use parametric methods and non-normal distributions shall use non-parametric methods. The rule identifies four statistical procedures, along with an alternative procedure that must meet the performance standard of § 257.93(g). The four specific statistical procedures provided in this final rule are: (1) A parametric analysis of variance followed by multiple comparison procedures to identify statistically significant evidence of contamination; (2) an analysis of variance based on ranks followed by multiple comparison procedures to identify statistically significant evidence of contamination; (3) a tolerance or prediction interval procedure; and (4) a control chart approach. The performance standard for the alternative method in subsection (g) is the same as the performance standard in the proposal, with minor revisions. EPA has deleted the performance standard "protect human health and the environment" in subsections (3), (4) and (5). While that standard is perfectly appropriate in a context in which a regulatory authority will apply the standard, EPA is concerned that a qualified professional engineer will be unable to certify that any alternative statistical method meets that standard. EPA received comments from professional engineers raising concern about their ability to certify that many of the requirements in the proposed rule had been met without further specification or clarification. To address those concerns, in those three provisions EPA has substituted a more objective performance standard that more precisely defines the relevant issues to be considered. Specifically, the subsections now specify that those approaches must be "at least as effective as any other approach in this section for evaluating groundwater."

The data objectives of the monitoring, in terms of the number of samples collected and the frequency of collection, must be consistent with the statistical method selected. Guidance on selecting a specific method is described in "*Unified Guidance Document: Statistical Analysis of Groundwater Monitoring Data at RCRA Facilities,*" March 2009, EPA 530/R–09–007. The owner or operator must indicate in the operating record the statistical method that will be used in the analysis of groundwater monitoring results.

The owner or operator must conduct the statistical comparisons between upgradient and downgradient wells within 90 days of completion of each sampling event and receipt of validated data. The statistical comparison must be conducted in order to determine if a statistically significant increase has occurred over background levels for each parameter or constituent required in the particular groundwater monitoring program that applies to the unit as determined under §§ 257.94(a) or 257.95(a). This has been adopted without revision from the proposal.

EPA is finalizing as proposed the prohibition in § 257.93(b) on field filtering groundwater samples because filtration of samples for metals analyses will not provide accurate information concerning the mobility of metals contaminants, the primary objective of groundwater sampling. Metal contaminants may move through fractured and porous media not only as dissolved species, but also as precipitated phases, polymeric species, or adsorbed to particles of colloidal dimensions (<10 microns). For an assessment of mobility, all mobile species must be considered, including suspended or colloidal particles acting as absorbents for contaminants. Filtration of groundwater samples for metals analyses will not provide accurate information concerning the mobility of metal contaminants because some mobile species in solution are likely to be removed by filtration before chemical analysis. Significant underestimations of mobility may result if filters (typically 0.45 micron) are used to separate dissolved and particulate phases.

In its approach to sampling EPA is specifying in the final rule that owners and operators use 'total recoverable metals' concentrations in measuring groundwater quality. Measurement of total recoverable metals captures both the particulate fraction and dissolved

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fraction of metals in natural waters. Exceedances of ambient water criteria on a total recoverable basis are an indication that metal loadings could be a stress to an ecosystem.

One commenter argued that to prohibit field filtering would potentially bias the results artificially high, particularly at sites where low yielding formations or naturally high levels of turbidity in groundwater are encountered. However, high turbidity can also be the consequence of faulty well design and/or construction, which causes the introduction of foreign materials (high turbidity) through created fracture pathways. A properly designed well should allow for sufficient groundwater flow for sampling, minimize the passage of materials into the well, and exhibit sufficient structural integrity to prevent collapse of the intake structure. It is vital that the well provide a representative hydraulic connection to the geologic formation of interest. Otherwise the water chemistry information cannot be correctly interpreted in relation to groundwater flow or transport of chemical constituents.

Sampling with no filtration means that increased importance is placed on proper well construction and purging sampling procedures to eliminate or minimize sources of sampling artifacts. There should be nothing in the well design that will lead to high levels of turbidity. Groundwater sampling should be conducted utilizing EPA protocol low stress (low-flow) purging and sampling methodology, including measurement and stabilization of key indicator parameters prior to sampling. For purposes of sampling, this final rule presumes that a properly constructed well is capable of yielding groundwater samples with low turbidity (≤5 Nephelometric Turbidity Units (NTU)), and by knowing the cause of turbidity the qualified professional engineer will be able to optimize well performance and reduce turbidity levels, eliminating the need for filtration.

EPA is revising § 257.93(i)(2) to specify a time period of 90 days to determine if a statistically significant increase over background concentrations of one of more of the contaminants has been detected. As proposed, this section specified: "Within a reasonable period of time after completing sampling and analysis, the owner or operator of the CCR landfill or surface impoundment must determine whether there has been a statistically significant increase over background at each monitoring well." Commenters pointed out that this section of the regulation was very vague, and potentially unenforceable. Several commenters suggested that once sampling and analysis had been completed, 90 days would be a reasonable amount of time to complete the statistical analysis to determine whether an exceedance had occurred. No commenter suggested a longer period of time was necessary and that timeframe is consistent with the Agency's experience of the timeframes necessary to complete such analyses. Accordingly, we have revised the provision to require the determination of a statistically significant increase to be made within 90 days of sampling and analysis.

4. Detection Monitoring Program

With three exceptions, EPA is finalizing the regulatory provisions relating to detection monitoring as proposed. The three revisions are the appendix III list of monitoring parameters; the required number of samples to determine background concentrations; and the availability of an option to conduct detection monitoring on a less frequent basis due to a lack of groundwater.

The detection monitoring phase of the groundwater monitoring program in this rule requires that the owners or operators of CCR units establish background concentrations for all monitoring parameters (appendix III and IV of part 257) and sample at least semiannually during the active life of the facility, closure, and post closure periods for a set of detection monitoring indicator parameters (appendix III of part 257).

In response to comments, EPA has revised appendix III to delete conductivity and sulfide from the list of monitoring parameters and to add calcium. Thus, the list of parameters included on the detection monitoring list is boron, calcium, chloride, fluoride, pH, sulfate and total dissolved solids (TDS). The Agency has deleted conductivity from the detection monitoring program because it is merely a proxy for TDS, which is already included on the list of parameters to analyze during detection monitoring. The Agency has also deleted sulfide because it occurs in groundwater only under strongly reducing conditions, and such conditions are rather rare at CCR disposal facilities. Calcium is being added to appendix III because it is an indicator of the extent of leaching from fly ash and FGD gypsum and because of the strong demonstrated link between the leaching of calcium and arsenic, which is one of the primary risk drivers identified in the risk assessment.

As discussed in the preceding section, in detection monitoring, a minimum of eight independent samples from each background and downgradient well must be collected and analyzed for the appendix III and IV parameters no later than 24 months from the effective date of the rule. During subsequent sampling events, at least one sample from each background and downgradient well must be collected and analyzed, although the total number of samples must be consistent with the statistical procedures selected and with the performance standard in § 257.93(g). See discussion above in section 3. Sampling and Analysis Requirements.

Under the proposed rule, monitoring would be required no less frequently than semiannually. In the final rule, semiannual sampling remains the general requirement; however, in response to comments, EPA has decided to include a provision that would allow an alternative sampling frequency if there is not adequate groundwater to flow to sample wells semiannually. Specifically, EPA received comment stating that there may be instances where there simply is not enough water available to collect and analyze on a semiannual basis, especially in western climates where the rate of groundwater recharge may be too slow or a lack of precipitation exists. The commenter also provided an example demonstrating that mining practices in adjacent areas can greatly alter the groundwater flow. Accordingly, EPA has included a provision to address the situations where there is insufficient groundwater available to collect and analyze samples around CCR units on a semiannual basis.

An owner or operator seeking to establish an alternative frequency must demonstrate that less frequent monitoring is necessary based on the following three factors: (1) Lithology of the aquifer and the unsaturated zone; (2) hydraulic conductivity of the aquifer and the unsaturated zone; and (3) groundwater flow rates. In addition, the rule requires the owner or operator to demonstrate that any alternate sampling frequency would be no less effective in ensuring that any leakage from the CCR unit will be discovered within a timeframe that does not materially delay the initiation of any necessary remediation measures. The owner or operator must have a qualified professional engineer certify that the alternative (*i.e.*, less frequent) monitoring will achieve this performance standard. The final rule also specifies that any alternate frequency during the active life (including closure) and the post-closure

care period shall be no less than annual. As noted, the owner or operator will bear the burden of justifying an alternate frequency under this regulation, and in any court proceeding brought to enforce these requirements. This means that any uncertainty or lack of information will be weighed against the entity seeking to justify the alternate frequency.

Consistent with the proposed rule, if the owner or operator determines that there is a statistically significant increase (SSI) over background for one or more of the parameters listed in appendix III at any monitoring well at the waste boundary, the owner or operator must place a notice in the operating record and on the facility's internet site indicating which parameters have shown statistically significant changes from background levels and notify the State Director.

The facility must also then establish an assessment monitoring program and begin monitoring within 90 days. The owner or operator has the opportunity to demonstrate that a source other than the CCR unit caused the statistically significant increase or that the statistically significant increase resulted from error in sampling, analysis, statistical evaluation or a natural variation in groundwater quality. Within 90 days, the owner or operator must prepare a report documenting this demonstration which must then be certified by a qualified professional engineer verifying the accuracy of the information in the report. If a successful demonstration is made within 90 days, the owner or operator may continue detection monitoring. If a successful demonstration is not made within 90 days, the owner or operator must initiate assessment monitoring.

Commenters raised concern that 90 days would not be sufficient to complete all of the activities necessary to determine whether the detection of an SSI was from another source than the CCR unit or was based on inaccurate results. The Agency recognizes that in some circumstances it could take more than 90 days to resample and have laboratories conduct new analyses, or to conduct field investigations to determine that another source is causing the contamination. As a result, § 257.94(e)(3) does not place an ultimate time limit for owners and operators to complete the demonstration. However, if after 90 days the owner or operator has not made a successful demonstration, (s)he must begin an assessment monitoring program. At this stage, there is evidence to indicate that a release has occurred from the CCR unit, and while EPA agrees that the facility may want to confirm that the information is accurate, it is critical that the facility not delay indefinitely the more targeted monitoring to determine whether a constituent of concern is contaminating groundwater. It would not be consistent with the statutory standard to allow a facility unlimited time to delay taking reasonable steps to assess, and if necessary, address potential contamination by continuing to resample until they obtain a "better" answer. Moreover, initiation of an assessment monitoring program does not involve an irretrievable commitment of resources or even a significant investment by the facility, but only requires the facility to begin more targeted sampling for constituents of concern. This represents a reasonable first step to address a potential threat to groundwater. This requirement is also in the MSWLF part 258 regulations. For more information see 56 FR 51078 (October 9, 1991).

Subsequent to initiating the assessment monitoring program, if an owner or operator demonstrates that the statistically significant increase resulted from an error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality, or was caused by a source other than the CCR unit, the owner or operator may cease assessment monitoring and return to detection monitoring. If the demonstration is successful, the owner or operator must have the demonstration certified by a qualified professional engineer, and is required by § 257.94(e)(3) to place a notice in the operating record, and on publicly accessible Internet site and send a copy of the report to the State Director.

5. Assessment Monitoring Program

EPA is adopting an assessment monitoring program that is largely identical to the program laid out in the proposal. However, as discussed in more detail below, some revisions have been made; some were made in response to comments, but most are conforming changes made to be consistent with changes adopted in other provisions, such as the detection monitoring program described previously.

Consistent with the proposed rule, if any of the detection monitoring parameters are detected at a statistically significant level over the established background concentrations, the owner or operator must proceed to the next step, assessment monitoring. Assessment monitoring requires annual sampling and analysis for the full list of constituents included in appendix IV. The number and frequency of samples required for assessment monitoring are the same as those established for detection monitoring. See discussion above in 3. Sampling and Analysis Requirements.

EPA has also revised the list of constituents in appendix IV by deleting the following constituents and parameters: Aluminum, boron, chloride, copper, iron, manganese, pH, sulfate, sulfide, and TDS; and adding the following constituents: Cobalt, lithium, and radium 226 and 228 combined. The following constituents and parameters are being removed from appendix IV because they are on appendix III and therefore will continue to be monitored throughout assessment monitoring: Boron, chloride, pH, sulfate and TDS. Although fluoride is on appendix III, we are also retaining it on appendix IV because it does have an MCL and was found to pose risks in the 2014 risk assessment, and therefore is appropriately considered to be a constituent that is relevant for purposes of corrective action. Aluminum, copper, iron, manganese, and sulfide have been removed because they lack maximum contaminant levels (MCLs) and were not shown to be constituents of concern based on either the risk assessment conducted for this rule or the damage cases (see Units X and XI of this document). Cobalt has been added to appendix IV because cobalt was found to be a risk driver in the 2014 risk assessment, based on certain waste management disposal practices that lead to highly acidic wastes conditions. Lithium is being added to appendix IV because it has been detected in several proven and potential damage cases at levels exceeding EPA's Regional Screening Level (RSL) of soil to groundwater and has been determined as potentially toxic if consumed concurrently with certain drug types.[117] Radium 226 and 228 combined (the sum of the radioactive isotopes radium-226 and radium-228) is being added because there is evidence from several damage cases of exceedances of gross alpha, indicating that radium from the disposal of CCR may be problematic. Appendix IV now contains antimony, arsenic, barium, beryllium, cadmium, chromium, cobalt, fluoride, lead, lithium, mercury, molybdenum,

[117] *EPA's Regional Screening Level (RSL) Soil to Groundwater Supporting Table (TR = 1E–6, HQ = 1)* May 2014/Mid-atlantic Risk assessment: *http://www.epa.gov/reg3hwmd/risk/human/rb-concentration_table/Generic_Tables/index.htm; and Health Consultation: Chesapeake ATGAS 2H Well Site Leroy Hill Road, Leroy, Leroy Township, Bradford County, Pennsylvania,* October 29, 2013. U.S. Department of Health and Human Services, Agency for Toxic Substances and Disease Registry Division of Community Health Investigations Atlanta, Georgia. *http://www.atsdr.cdc.gov/.*

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selenium, thallium and radium 226 and 228 combined.

If any appendix IV constituents are detected in any appendix IV analyses, the owner or operator must notify the State Director and continue to monitor, at least semiannually, for both the specific constituents in appendix IV that were detected and all parameters in appendix III. EPA has decided to also include a provision to allow an alternative sampling frequency if there is not adequate groundwater to flow to sample wells semiannually, consistent with the revised provision adopted for the detection monitoring program. If the owner or operator demonstrates at any time during assessment monitoring that all of the detected appendix III and IV constituents are at or below background values for two consecutive sampling events, (s)he must notify the state and may return to detection monitoring. In general, EPA expects that appendix III constituents are unlikely to remain elevated once measures have been taken to address the release of the detected appendix IV constituents. But should appendix III constituent levels remain elevated, detection monitoring continues to be necessary to determine whether another source of contamination is present.

After obtaining the sampling results the owner or operator must place a notice in the operating record and on the facility's internet site indicating which appendix IV constituents have been detected and notify the State Director. Within 90 days and on at least a semiannual basis thereafter, the owner or operator must resample all wells, conduct analyses for all parameters in appendix III and for those constituents in appendix IV that were detected in the initial assessment monitoring sampling event. The results of this resampling must be placed in the owner or operator's operating record, as well as its publicly accessible internet site. The results of the resampling must also be sent to the State Director. These provisions have been adopted without change from the proposal.

For each appendix IV constituent that is detected, a groundwater protection standard must be set. The groundwater protection standards must be the MCL or the background concentration level for the detected constituent, whichever is higher. If there is no MCL promulgated for a detected constituent, then the groundwater protection standard must be set at background. The proposed rule would have allowed the owner or operator to establish an alternative groundwater protection standard for constituents for which MCLs have not been established provided that the alternative groundwater protection standard has been certified by an independent registered professional engineer and the state has been notified that the alternative groundwater protection standard has been placed in the operating record and on the owner's or operator's publicly accessible internet site. This provision had been adopted from the part 258 regulations, but was determined to be inappropriate in a self-implementing rule, as it was unlikely that a facility would have the scientific expertise necessary to conduct a risk assessment, and was too susceptible to potential abuse. Additionally, numerous comments were received suggesting that only those constituents with MCLs be included in appendix IV. The commenters were concerned that only MCLs are enforceable. With the exception of cobalt, lead, lithium and molybdenum (included on appendix IV because of their relevance in the risk assessment and damage cases), all appendix IV constituents have an MCL. In the proposed rule, as stated above, owner or operators were allowed to establish certain types of alternative groundwater protection standards. In the final rule, if a constituent has no MCL (*i.e.,* cobalt, lead, lithium and molybdenum), their groundwater protection standards will be their background levels. These background standards are sufficiently precise that they are enforceable.

The owner or operator must compare the levels of any detected appendix IV constituents to the appropriate groundwater protection standard. If the concentrations of all appendix IV constituents are shown to be at or below background values for two consecutive sampling events using the statistical procedures required by § 257.93, the owner or operator of the CCR disposal facility must place that information in the operating record and on the facility's publicly accessible internet site and notify the State Director. The owner or operator may then return to detection monitoring.

If the concentrations of any appendix III or IV constituents are above background values, but all concentrations are determined to be below the groundwater protection standard using the statistical procedures required by this rule, the owner or operator must continue assessment monitoring program.

If, however, the monitoring indicates a statistically significant increase for any appendix IV constituent over the groundwater protection standard, the owner or operator is required to notify the State Director and local officials of this finding and place a notice in the operating record and on the owner or operator's publicly accessible internet site.

The owner or operator also must characterize the nature and extent of the release. As part of characterizing the nature and extent of the release, the owner or operator must install additional wells, as necessary to define the contaminant plume(s) and collect data on the nature and estimated quantity of the material released. Adequate characterization of the release is critical in designing and effectively implementing a protective corrective action program if groundwater remediation is necessary. The purpose of these additional wells is to delineate the contaminant plume boundary and to eventually demonstrate the effectiveness of corrective action in meeting the groundwater protection standard.

Because the requirements for additional monitoring are entirely specific to the site conditions and the size and nature of the release, the Agency is not able to set requirements that precisely specify the location or the number of additional wells that must be installed. Instead EPA has adopted an approach that corresponds to the approach to designing the original groundwater monitoring system under § 257.91. The regulations establish a general performance standard ("install additional wells as necessary to define the contaminant plume") and specify a true minimum of installing at least one well at the facility boundary in the direction of contaminant migration in order to ascertain whether the contaminants have migrated past the facility boundary. The regulations also establish a rebuttable presumption that this minimum is insufficient, requiring the owner or operator to justify a decision to install only this minimum. The requirement to justify the decision to only install the minimum number of additional wells is a revision from the proposal that has been adopted to be consistent with the Agency's overall approach to developing an effective groundwater monitoring system.

The Agency has also added some clarification to the proposed requirement to characterize the nature and extent of the release, by requiring the owner or operator to collect data on the nature and estimated quantity of material released, including specific information on the constituents listed in appendix IV and the levels at which they are present in the material released. This information will be necessary to help the owner or operator characterize the release and assist in ultimately deciding on a remedy.

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If contamination has migrated off-site, the owner or operator must notify individuals who own land or reside on land overlying the plume.

In addition to characterizing the nature and extent of the release, the owner or operator must initiate an assessment of corrective measures within 90 days of finding a statistically significant increase over background concentrations, and select the appropriate remedy. During this phase, the owner or operator is required to continue at least semiannual monitoring (or an alternative frequency, no less than annually) for all appendix III constituents and for those appendix IV constituents exceeding the groundwater protection standard. To be consistent with the provisions in detection monitoring, EPA has included a provision that would allow the owner or operator to demonstrate that a source other than their CCR unit caused the contamination or that the statistically significant increase above groundwater protection standards resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality. This alternative option will not delay compliance with the next phase of the groundwater monitoring and corrective action program. Thus, until such a demonstration is made, the owner or operator must comply with the other requirements of this section, including initiating the assessment of corrective measures. At this stage, the evidence that the CCR unit is leaking is stronger, and the owner or operator has previously had the opportunity to demonstrate that the finding was made in error under the detection monitoring program, so no further delay in initiating measures to address any groundwater contamination is warranted.

Another change since the proposal is that in addition to complying with all of the corrective action requirements—*i.e.,* initiating an assessment of corrective measures, followed by selection of a remedy and implementation of a corrective action program—if the unit is an unlined surface impoundment, it must either retrofit or initiate closure. Further, where the facility has chosen to install a multi-unit groundwater monitoring system, the detection of an SSI of an appendix IV constituent would trigger the corrective action and closure (or retrofit) of all of the unlined surface impoundments covered by that monitoring system, as there will be no way to isolate a particular unlined unit as the source of the contamination. These requirements are discussed in more detail in the Closure section.

6. Assessment of Corrective Measures

This section of the regulations also largely mirrors the analogous provisions in the proposed rule. EPA added some language to reflect that this section is not limited to the remediation of groundwater from a leaking CCR unit but will also apply to contamination caused by any kind of release from a CCR unit. EPA also made some minor revisions in response to comments, and some editorial changes to conform this provision to changes made in other sections of the rule.

Consistent with the proposal, § 257.96(a) specifies that the assessment of corrective measures must be initiated within 90 days of detecting a statistically significant increase of any of the constituents listed in appendix IV, at a level exceeding the groundwater protection standard(s), or of otherwise documenting a release of contaminants from the CCR unit. The regulation also requires the assessment of corrective measures to be completed in 90 days of such a finding, but in response to comments, EPA is adopting a provision that will allow for a single 60 day extension. Multiple commenters argued that 90 days was not adequate to complete the assessment of corrective measures. Commenters stated that for situations with complex hydrogeology, additional studies and sampling may be required in order to assess potential contributing offsite sources, background levels, and possible remedies. They stated that identification of remedy alternatives, collection and analysis of data used to evaluate remedy alternatives, and discussions with vendors/contractors regarding availability of labor and materials are all critical steps in the remedy selection process. As explained in the "Technical Manual Solid Waste Disposal Facility Criteria," EPA530–R–93–017, USEPA, November, 1993, Chapter 5, Subpart E, Ground-Water Monitoring and Corrective Action, the owner or operator will need to: (1) Identify and remediate the source of contamination; and (2) identify and remediate the known contamination. The factors that must be considered in assessing corrective measures include source evaluation, plume delineation, groundwater assessment and source control. Based on the comments received, as well as the Agency's own experience, EPA recognizes that there may be complex situations that require more time to develop a careful and well-thought out corrective measures assessment. Therefore, the final rule has been modified to allow up to an additional 60 days to complete the assessment of corrective measures, provided that a qualified professional engineer certifies that the additional time is necessary. The initial 90 days plus the additional 60 days, which is within the range of time suggested by the commenters, would provide the owner or operator up to 150 days to complete the corrective measures assessment, which EPA expects will be sufficient. The certification must be placed in the operating record, on the owner's or operator's publicly accessible internet site and submitted to the proper state official.

The rule requires the owner or operator to assess the effectiveness of potential remedies in meeting the objectives of § 257.97 by addressing at least: (1) Performance, reliability, ease of implementation and potential impacts; (2) time requirements; and (3) institutional requirements. The proposed rule also included consideration of the costs of remedy implementation. However, that language came directly from the MSWLF rule in part 258. Because Congress did not authorize the consideration of costs in establishing minimum national standards under RCRA section 4004(a), we have removed this factor. In evaluating the performance, reliability, ease of implementation, and potential impacts of each remedy, the owner or operator should evaluate whether specific remedial technologies are appropriate to the problem and the ability of those technologies to achieve the groundwater protection standards. Analysis of a remedy's reliability should include an assessment of the effectiveness of the remedy in controlling the source of the release and its long-term reliability. Source control measures need to be evaluated to limit the migration of the plume, and to ensure an effective remedy. The regulation does not limit the definition of source control to exclude any specific type of measure to achieve this. Remedies must control the source of the contamination to reduce or eliminate further releases by identifying and locating the cause of the release. Source control measures may include the following: Modifying the operational procedures (*e.g.,* banning waste disposal); undertaking more extensive and effective maintenance activities (*e.g.,* excavate waste to repair a liner failure); or, in extreme cases, excavation of deposited wastes for treatment and/or offsite disposal. Construction and operation requirements also should be evaluated. The analysis of the timing of potential remedies should include an evaluation of construction, start-up, and

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completion time. Timing is particularly important if contamination has migrated off-site. Institutional requirements such as local permit or public health requirements may affect implementation of the remedies evaluated and should be assessed by the owner or operator.

The proposed rule included a provision that would allow an owner or operator to determine that compliance cannot be reasonably achieved with any currently available methods. This has been deleted from the final rule. The Agency determined that without state oversight or a permitting program, that provision was potentially subject to abuse and thus, inappropriate to include in a self-implementing rule.

As part of evaluating potential remedies, the owner or operator must hold a public meeting to discuss the remedies under consideration (prior to selecting a final remedy). Once the owner or operator has selected a remedy, he must place a description of the selected remedy in the operating record, on the owner or operator's publicly accessible internet site and notify the State Director.

7. Selection of Remedy

This section of the final rule has been adopted with only minor changes from the proposal. As in the prior section, EPA has revised certain provision to reflect that this section will also apply to the cleanup of contamination caused by a release from a CCR unit. EPA also deleted a provision that had been adopted from the part 258 regulations, but that was determined to be inappropriate in a self-implementing rule as it was too susceptible to potential abuse.

Based on the results of the corrective measures assessment conducted, the owner or operator must select a remedy. The selected remedy must attain all of the performance standards listed in subsection (b). Specifically, the remedy must protect human health and the environment, attain the groundwater protection standards, control the sources of releases so as to reduce or eliminate, to the maximum extent practicable, further releases of appendix IV constituents into the environment, and comply with any relevant standards for management of wastes generated as a result of the remedial activities. EPA included an additional criterion more directly related to remediation of contamination associated with a release, such as from a collapse or structural failure of a CCR unit, which requires the remedy to "remove from the environment as much of the contaminated material that was released from the CCR unit as is feasible, taking into account factors such as avoiding the inappropriate disturbance of sensitive ecosystems." Together, these criteria reflect the major technical components of any kind of clean up remedy.

The rule also specifies decision criteria to be considered by the owner or operator in selecting the most appropriate remedy. These include: (1) Long and short term effectiveness, and degree of certainty of success; (2) effectiveness of remedy in controlling the source to reduce further releases; (3) ease or difficulty of implementation; and (4) community concerns. Additionally, the rule requires the owner or operator to specify a schedule for implementing and completing the remedial activities. The rule requires the owner or operator to set the schedule because it is impossible for EPA to establish a single schedule appropriate for all possible situations; the schedule will necessarily depend on the nature and size of the contamination, among other factors. The rule outlines six factors to be considered in establishing a schedule for completing remedies (§§ 257.97(d)(1–6)). These factors are: (1) Extent and nature of contamination; (2) reasonable probabilities of remedial technologies in achieving compliance with the groundwater protection standards; (3) availability of treatment or disposal capacity for CCR managed during implementation of the remedy; (4) potential risks to human health and the environment; (5) resource value of the aquifer; and (6) other relevant factors. EPA had included one additional factor in the proposal: "The desirability of utilizing technologies that are not currently available, but which may offer significant advantages over already available technologies in terms of effectiveness, reliability, safety, or ability to achieve remedial objectives." EPA considered that this provision, which could be used to justify delaying remediation measures, was potentially subject to abuse and thus, inappropriate to be included in a self-implementing rule.

For similar reasons, EPA deleted the provisions in the proposal, subsections (e) and (f) that would authorize a facility to determine that remediation of a release is not necessary. These sections which came from the MSWLF rule in part 258 are appropriate where there is state oversight. The preamble to the final MSWLF rule specifically discusses situations in which an approved state may decide not to require cleanup of hazardous constituents released to groundwater from a MSWLF (see 56 FR 51090). However, there is no similar guarantee that an individual facility will act in the public interest.

8. Implementation of the Corrective Action Program

The proposed rule required the owner or operator to include a schedule for initiating the remedial activities in the schedule for implementing the remedy (§ 257.97(d)). The Agency understands that selecting a remedy is closely related to the assessment process and cannot be accomplished unless a sufficiently thorough evaluation of alternatives has been completed. The process of documenting the rationale for selecting a remedy requires that a report be placed in the operating record that clearly defines the corrective action objectives and demonstrates why the selected remedy is anticipated to meet those objectives. The report must identify how the remedy will be protective of human health and the environment, attain the groundwater protection standards (either background or MCLs), attain source control objectives, and comply with waste management standards.

The selection of a remedy also involves a public meeting with interested parties before finally selecting a remedy. For these reasons, the Agency is not establishing a deadline for completing the remedy selection process, but rather expects it to be completed as soon as practicable. Once the assessment of corrective measures has been completed within the timeframe specified in this rule, and the public meeting has occurred, the facility owner or operator must select a remedy and begin implementing that remedy as soon as is practicable. It is vitally important that the facility selects a remedy as soon as practicable and begins designing and implementing that remedy, so that releases to groundwater are addressed without unnecessary delay. EPA understands that there are a variety of activities that may be necessary in order to select the appropriate remedy (*e.g.,* discussions with affected citizens, state and local governments; conducting on-site studies or pilot projects); and, once selected, to implement the remedy (*e.g.,* securing on-site utilities if needed, obtaining any necessary permits, etc.). That is why EPA does not find it appropriate to set specific timeframes for selecting the remedy or to begin implementing the selected remedy. However, in order to ensure that the community is kept informed as to the progress of selecting and implementing the remedy, EPA is requiring that the facility owner or operator, on a semiannual basis, post status reports/updates on their progress

to their publicly accessible internet site and submit these to the state.[118]

However, the Agency has concluded that it is reasonable to require that once a remedy has been chosen, the owner or operator of the CCR unit must begin to implement that remedy within a specified period of time. Consistent with the timeframes throughout this section, the final rule requires that within 90 days of selecting a remedy, the owner or operator must have initiated corrective measures, including any interim measures determined to be appropriate, and have established a corrective action groundwater monitoring program (and begin following it). (§ 257.98). This is a reasonable timeframe in which to begin these activities based on EPA's long experience in conducting and overseeing cleanup activities.

The remedy would be considered complete when the owner or operator demonstrates compliance with the groundwater protection standards for a period of three consecutive years, and all other actions required to meet the performance standards in § 257.97(b) have been satisfied (*e.g.,* source control). The owner or operator must obtain certification that the remedy is complete from a qualified professional engineer, and must notify the State Director. The certification must also be placed in the operating record and on the owner or operator's publicly accessible Internet site.

The Agency deleted the provision that allows an owner or operator to determine that compliance cannot be reasonably achieved with any currently available methods. The Agency determined that without state oversight or a permitting program, that provision was potentially subject to abuse and thus, inappropriate to be included in a self-implementing rule.

9. Timing Overview

The groundwater monitoring regulations require that the owner or operator of existing CCR units must comply with § 257.90–§ 257.94 within 30 months of the date of publication of the rule. Essentially, that means that by the end of 30 months, the owner or operator must (1) install the groundwater monitoring system; (2) document the sampling and analysis procedures; (3) establish which statistical tests will be used to determine exceedances; (4) sample all wells to have a minimum of 8 samples for all appendix III and IV parameters; and (5) determine if there is a statistically significant exceedance of any appendix III parameter, which would trigger assessment monitoring.

New CCR units must comply with §§ 257.90–257.93, including the requirement under § 257.94(b) to collect and analyze eight independent samples from each well for the parameters listed in appendix III and IV to this part to determine background levels for all appendix III and IV constituents, before commencing operation. Essentially, that means that before receiving CCR waste, the owner or operator must (1) install the groundwater monitoring system; (2) document the sampling and analysis procedures; (3) establish which statistical tests will be used to determine exceedances; and (4) sample all wells to have a minimum of eight samples for all appendix III and IV parameters.

If assessment monitoring is triggered, within three months the owner or operator must sample all wells for all appendix IV constituents (minimum of one sample) and resample (minimum of one sample) all wells for all appendix III parameters and those appendix IV constituents that were detected in the first round of sampling. The owner or operator could also simultaneously use this three month timeframe to demonstrate that the statistically significant increase found in detection monitoring was due to another source or sampling and analysis error. While conducting assessment monitoring, the owner or operator must continue sampling for all appendix III constituents and any appendix IV detected constituents semiannually. The owner or operator must sample for all appendix IV constituents annually.

The owner or operator must also establish groundwater protection standards (MCL or background levels) for all appendix IV constituents detected during sampling.

If one or more appendix IV constituents are detected at statistically significant levels above the groundwater protection standards established, or a release from a CCR unit has been detected, corrective action is triggered. The owner or operator must characterize the nature and extent of the release by installing additional monitoring wells, collecting data on the quantity and concentration levels of regulated constituents in the released material, sampling and notifying the State Director, local government officials, and any persons who own land or reside on the land that overlies the plume if the plume has migrated off site. The owner or operator must also place the notification in their operating record and on their publicly accessible Internet site.

If corrective action is triggered, within three months the owner or operator must initiate an assessment of corrective measures. If the CCR unit is an unlined surface impoundment, the unit must stop receiving CCR and non-CCR wastes and initiate closure of the unit or begin to retrofit the unit within six months. The owner or operator could also simultaneously use these three months to initiate an assessment of corrective measures to demonstrate that the statistically significant increase found during assessment monitoring was due to another source or sampling and analysis error.

The assessment of corrective measures must be completed in three months, with the possibility of an additional two months if the owner or operator demonstrates the need for additional time. The owner or operator must continue assessment monitoring and provide notification of the corrective measures assessment to the State Director and place the assessment in the operating record and on the owner's or operator's publicly accessible Internet site. The owner or operator also must discuss the results of the corrective measures assessment at least one month prior to selection of remedy in a public meeting.

Within three months of selecting a remedy, the owner or operator must initiate remedial activities. Corrective action is completed when the owner or operator demonstrates compliance with the groundwater protection standards for three consecutive years.

*L. Closure of Inactive Units.*

As discussed in Unit VI.A of this document, EPA proposed that inactive CCR surface impoundments that had not completed closure in accordance with specified standards by the effective date would be subject to all of the requirements applicable to existing CCR surface impoundments. EPA adopted this approach to create an incentive to expedite the closure of these units, with all of the significant risk mitigation that such a measure would entail. EPA is retaining this general approach in the final rule, but has revised the provision to grant inactive CCR surface impoundments more time to complete closure, consistent with the other closure provisions in the final rule. The

[118] As evidenced in 42 U.S.C. 6971(f), Congress intended that the OSHA be able to enforce its regulations to protect workers exposed to hazardous waste and that EPA and OSHA would work together to ensure that. EPA is clarifying that it intends that the CCR disposal rule not preempt applicable OSHA standards designed to protect workers exposed to CCRs; thus EPA's final rule on CCR disposal will apply in addition to any applicable OSHA standards. The Agency has added specific regulatory language in this section to address this intent.

final rule extends the deadline to three years from publication of the rule in the **Federal Register**.

The proposal was based on EPA's belief that the timeframes between publication of the final rule and the effective date would be sufficient for facilities to close inactive CCR surface impoundments. This was particularly true under the subtitle C option, where the timeframe between publication and the effective date could be as long as 18 months, due to the need for subsequent action by authorized states. Under the proposed rule, the maximum amount of time a facility would have to initiate and complete closure of a disposal unit was seven months. However, as discussed elsewhere in this preamble, EPA received numerous comments raising concern that these timeframes would essentially be "impossible to meet" for surface impoundments located in certain geographic and climatic conditions, as well as for all of the larger units. These comments convinced EPA that it had not adequately accounted for the complexities inherent in electric generating facility operations, and the different characteristics of CCR surface impoundments in designing the closure provisions in the proposal. EPA has revised the timeframes applicable to closures in the final rule accordingly in light of these issues. See Unit VI.M of this document. These same considerations apply with respect to this provision, and additional time is therefore necessary to make this option truly viable.

EPA selected three years based primarily on two factors. EPA initially focused on the minimum amount of time necessary to close a CCR surface impoundment. As discussed in more detail in Unit VI.M of this document, there can be a substantial range in the amount of time needed to close a surface impoundment, depending on, for example, the size and location of the unit.

However, a critical factor in EPA's decision is that under this approach these units will not be subject to the rule's groundwater monitoring or structural stability requirements (provided they complete closure within three years). Moreover, based on the information in the record, it appears highly unlikely that groundwater monitoring is currently being conducted at these units (as discussed in Unit IV.A of this document, the information on groundwater monitoring requirements applicable to existing units was extremely sparse, but many older units appear to lack effective groundwater monitoring systems). EPA considered that allowing these inactive units to remain in place without taking measures to address the continuing threat that these units present for a substantial amount of time could not be justified. EPA therefore focused on the amount of time authorized under the rule for implementation of the groundwater monitoring requirements (*i.e.,* 2 years from the effective date) and for key structural stability requirements (*i.e.,* 18 months to complete key analyses).

As discussed in more detail in the next section, the information in the record demonstrates that it is feasible to complete the closure of CCR surface impoundments within three years. EPA recognizes that larger CCR surface impoundments (*i.e.,* above 40 acres) may not be able to close within this timeframe. However, to be able to support this provision, EPA must balance the risk mitigation achieved by closure of CCR surface impoundments against the risks inherent in allowing inactive CCR surface impoundments to remain in place for longer periods of time. The longer inactive CCR impoundments remain without all of the protections provided by the final rule, the greater the potential for significant health and environment impacts. Larger units are also the ones more likely to present the highest risks, and so warrant the greater oversight provided by application of all of the technical criteria to their operation (and closure). Consequently, EPA is unable to justify expanding this option to include the longer timeframes available under §§ 257.102 or 257.103.

The criteria for conducting the closure of inactive CCR surface impoundments are essentially the same as those applicable to active CCR units. Inactive units can either clean close units, or close with waste in place, subject to same performance standards in § 257.102 for all other CCR units. If an inactive CCR surface impoundment is completely closed within the three year timeframe, no other requirements apply to that unit. This means that no groundwater monitoring or other post-closure care requirements would apply to these units. Once an inactive CCR surface impoundment has been breached and dewatered, the risks are essentially the same as the risks associated with an inactive CCR landfill, which are not subject to any requirements under the final rule.

However, owners or operators of inactive CCR surface impoundments that have not completed closure within this timeframe must comply with all of the requirements applicable to existing CCR impoundments. If the facility intends to maintain the inactive unit indefinitely, whether to provide potential future capacity, or to continue to dredge the unit to provide material for beneficial use, or with the idea that it may be repurposed for other facility operations (*e.g.,* to manage stormwater), there is no basis for distinguishing between these units and actively managed units on the basis of the potential risks. Thus, such units would need, for example, to meet all of the location and structural stability criteria (which could independently compel closure of the unit), install the groundwater monitoring system, and begin to monitor within the timeframes established in the final rule. This also means that any facility that initiates closure under this provision but fails to complete it within this timeframe, must comply with all groundwater monitoring requirements in §§ 257.90–98 (*e.g.,* install groundwater monitoring wells) as well as all of the post-closure care requirements.

*M. Closure and Post-Closure Care*

Closure and post-closure care are an integral part of the design and operation of CCR landfills and CCR surface impoundments.[119] EPA solicited public comment on closure and post-closure care requirements under a subtitle D approach in the proposed rule and sought additional comment on specific closure requirements in a subsequent notice of data availability.

For CCR landfills, the proposed closure and post-closure care requirements were modeled on current regulations that apply to municipal solid waste landfills, which are codified in part 258. In some cases, the proposed requirements were modified to reflect the lack of a mandatory permitting mechanism (see Unit V.A. of this preamble for additional information), in addition to other changes EPA believed were appropriate to ensure that there would be no reasonable probability of adverse effects from the wastes that remain after a CCR unit had closed. For CCR surface impoundments, the Agency modeled the proposed requirements on current regulations that apply to interim status hazardous waste surface impoundments, which are codified in part 265. Some additional proposed provisions were based on requirements currently applicable to water, sediment, or slurry impoundments and

[119] As discussed in the proposed rule, EPA's "Guide for Industrial Waste Management" documents the general consensus on the need for effective closure and post-closure care requirements (Chapter 11). This guide can be accessed at *http://www.epa.gov/epawaste/nonhaz/industrial/guide/.*

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impounding structures that are regulated by the MSHA. See 30 CFR part 77, subpart C.

The proposed rule included a number of closure and post-closure criteria, including: (1) Requirements to prepare closure and post-closure plans; (2) requirements for conducting closure of a CCR unit when the CCR is removed and when the CCR is left in place, including design criteria for a final cover system; (3) timeframes to commence and complete closure activities; (4) closure and post-closure care certification requirements; and (5) requirements for conducting post-closure care. The Agency received numerous comments on the proposed closure and post-closure criteria, with the majority of comments pertaining to the proposed timeframes for closure (*i.e.,* timeframes for commencing and completing closure) of a CCR surface impoundment. As a result of these comments, EPA solicited additional comments on the timeframes for closure in a NODA published on August 2, 2013 (NODA 3). See 78 FR at 46944. The sections below explain the approach and rationale for the final rule closure and post-closure care criteria based on the comments received in response to the proposed rule and the NODA.

1. Closure Plan

The Agency proposed to require that the owners or operators of CCR landfills and CCR surface impoundments prepare a written closure plan describing the closure of the unit and providing a schedule for implementation of the plan. 75 FR at 35207–08. The closure plan would describe the steps necessary to close the CCR unit at any point during the active life based on recognized and generally accepted good engineering practices. The proposal also identified the minimum information necessary to include in the closure plan. This information included: (1) An estimate of the largest area of the CCR unit that would ever require a final cover during the active life of the CCR unit; (2) an estimate of the maximum inventory of CCR that would ever be present on-site over the active life of the CCR unit; (3) a description of the final cover and the procedures to be used to install the final cover; (4) a description of how the facility will provide for major slope stability following closure; (5) a description of the measures the owner or operator will adopt to preclude the probability of future impoundment of water, sediment, or slurry; and (6) a schedule for the implementation of the closure plan. See proposed § 257.100(a) and (g). The proposed rule would also have required each owner or operator to develop the closure plan by the effective date of the final rule. Finally, EPA proposed to require the owner or operator to have the closure plan certified by an independent registered professional engineer, in addition to complying with all of the notification and posting requirements under the rule.

EPA received few public comments on either the proposal to develop a closure plan or the individual elements of the closure plan. Some commenters generally supported the requirement for an owner or operator to develop a closure plan for the CCR unit, and no commenters opposed it. However, one commenter requested that EPA include more specific requirements for slope stability in the regulatory language beyond the general requirement to address major slope stability in the closure plan for units that close with waste in place.

The Agency agrees that the proposed regulatory language should provide more specific criteria defining the expectations with regard to major slope stability. The proposed regulation merely required the owner or operator to "provide for major slope stability" in the closure plan, or in other words, to include measures to ensure that slope stability issues will be accounted for in designing the final cover. See 75 FR 35252.

EPA explained that unit closure must provide for major slope stability to prevent the sloughing of the cover system over the wastes that will remain in the CCR unit over the long term. Sloughing of a land slope can occur when the earth material becomes saturated with water and incapable of maintaining the slope resulting in the movement or sliding of the earth material. 75 FR at 35209. Slope stability is a critical issue in the design of final cover systems for both surface impoundments and landfills because cover system slope instability has been attributed to a number of final cover system failures.[120] More specifically, the primary causes of final cover system slope failure during construction have been identified as: (1) Placing soil over the sideslope geosynthetics from the top of the slope downward, rather than the toe of the slope upward; (2) using presumed values for critical interface shear strengths that were not conservative; and (3) using interface shear strength values from laboratory tests performed under conditions not representative of the actual field conditions. For final cover system slope failures after rainfall or thaw, the primary causes of failure have been identified as: (1) Not accounting for seepage forces; (2) clogging of the internal drainage layer, which leads to increased seepage forces; and (3) not accounting for moisture at the geomembrane and compacted clay liner interface (which weakened the interface) due to both rain falling on the compacted clay liner surface during construction and freeze-thaw effects.

Given that slope stability is a critical issue in the design and eventual performance of a final cover system, EPA has adopted a new criterion in the performance standard that all closures must meet: The owner or operator must ensure that the CCR unit is closed in a manner that will "provide for major slope stability to prevent the sloughing or movement of the final cover system during closure and throughout the post-closure care period." See § 257.102(d)(1)(iii). Or in other words, the owner or operator must design a final cover system with any measures necessary to ensure that the major slopes of the closed CCR unit remain stable. Consistent with the proposal, the closure plan must discuss how the final cover system will achieve the performance standards specified in the regulation, which will necessarily include how the measures taken to address major slope stability. As explained in the proposed rule, the original provision was based on existing MSHA standards, specifically the requirements under 30 CFR 77.216–5 which apply to abandoned water, sediment or slurry impoundments and impounding structures.[121] 75 FR 35208–09. Under these requirements major slope stability includes long term stability considerations, such as "erosion control, drainage, etc." These issues are equally relevant to the closure of CCR units, and EPA expects facilities to account for these factors in their final closure plans.

The remaining information elements of the closure plan have been adopted without revision (although EPA has reorganized the final regulatory text for greater clarity). These are briefly summarized below:

a. An estimate of the largest area of the CCR unit ever requiring a final cover during the active life of the CCR unit. If

[120] USEPA, "Assessment and Recommendations for Improving the Performance of Waste Containment Systems," EPA/600/R–02/099, December 2002.

[121] The term "abandoned" is defined in the MSHA regulations under 30 CFR 77.217, and as applied to an impoundment or impounding structure such term means that work on the structure has been completed in accordance with a plan for abandonment approved by the District Manager.

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the owner or operator routinely closes portions of a CCR unit as the design capacity is reached, the closure plan should indicate the largest area of the CCR unit that will be open (and requiring a final cover) at one time.

b. An estimate of the maximum inventory of CCR ever on-site over the active life of the CCR unit. If the owner or operator routinely closes portions of a CCR unit as the design capacity is reached, the closure plan should indicate the maximum inventory of CCR that will be open (and requiring a final cover) at one time.

c. A description of the final cover and the procedures to be used to install the final cover. The closure plan should also discuss how the closure performance standard will be achieved.

d. A description of the provisions to preclude the probability of future impoundment of water, sediment, or slurry. The final grades of the final cover system should promote surface water run-off and minimize erosion. The closure plan should also discuss the steepness of the slopes of the final cover system, in addition to the vertical spacing and width of benches.

e. A schedule for the implementation of the closure plan.

This rule also provides new procedures for amending an existing written closure plan. While the proposed rule did not specifically allow or require the owner or operator to revise an existing closure plan, EPA recognizes that available information and conditions known at the time the closure plan is prepared may very well change during the active life of the CCR unit, which could be decades in some cases. In order to eliminate any potential confusion over whether an owner or operator is allowed under this rule to revise the closure plan to reflect a change in conditions or circumstances, the final rule adopts new procedures for amending a written closure plan. These new procedures allow the owner or operator to revise the closure plan at any time provided the revised plan is placed in the facility's operating record, in addition to complying with all of the notification and posting requirements under the rule. Furthermore, the final rule requires the closure plan be amended any time there is a change in conditions that would substantially affect the written closure plan in effect.

Finally, in a departure from the proposed rule, the final rule provides owners and operators one year from the rule's effective date to prepare the initial written closure plan, which is one year longer than proposed. EPA made this change as part of its effort to coordinate the compliance and implementation timeframes in the CCR rule with another Agency rulemaking—the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG) rulemaking—that may affect owners and operators of CCR units. See 78 FR 34442. As explained in that proposal, consistent with RCRA section 1006(b), EPA has sought to effectively coordinate any final RCRA requirements with the ELG requirements, to minimize the overall complexity of these two regulatory structures, and to facilitate the implementation of engineering, financial and permitting activities. EPA's goal is to ensure that the two rules work together to effectively address the discharge of pollutants from steam electric generating facilities and the human health and environmental risks associated with the disposal of CCRs, without creating avoidable or unnecessary burdens.

EPA proposed to require facilities to complete a closure plan by the rule's effective date, or six months following the rule's publication. However, this would have required owners or operators to prepare closure plans approximately three months prior to publication of the ELG final rule. Given that an understanding of the ELG rule would likely affect the details and content of a closure plan, the Agency concluded that it would make no sense to require an owner or operator to prepare a closure plan within six months, only to have them update it months later, after the owner or operator understands the requirements of both the CCR and ELG final rules. No measureable environmental or health benefit would be gained by having a closure plan in place for those three months. Moreover, EPA wants to ensure that closure plans are well considered, and the knowledge that a plan may need to be substantially revised in the near future could create a contrary incentive.

By extending the deadline for preparation of the closure plan by one year, owner or operators will have slightly more than six months after the ELG rule is published to complete a closure plan. This is consistent with the six month timeframe EPA originally proposed, which as noted, would have required completion of the closure plan within six months of publication of the final CCR rule.

2. Closure of a CCR Unit Through Removal and Decontamination

The proposed rule would have allowed facilities to close a CCR unit either through CCR removal and decontamination of all areas affected by releases from the CCR unit ("clean closure") or with CCR in place with a final cover system. The Agency proposed that if the owner or operator elects to clean close a CCR unit, CCR removal and decontamination are complete when constituent concentrations throughout the CCR unit and any areas affected by releases from the CCR unit do not exceed the numeric cleanup levels for those constituents found in CCR established by the state in which the CCR unit is located, to the extent that the state has established cleanup levels. 75 FR 35208. In the absence of state cleanup levels, the proposal stated that metals should be removed to either statistically equivalent background levels, or to maximum contaminant levels or health-based numbers. Once a facility had completed clean closure of a CCR unit, EPA proposed that post-closure care would not be required for that unit. EPA also noted that it was considering whether to adopt a further incentive for clean closure, under which the owner or operator could remove the deed notation required under the proposed rule, once all CCR has been removed from the facility and notification provided to the state.

Several commenters urged EPA to not require clean closure as the only method of closing a CCR unit, arguing that clean closure is not feasible or not necessary. Others acknowledged that clean closure is not only a viable option for their CCR units, but in some cases it would be "the only prudent closure option." A few commenters suggested criteria to determine the conditions under which clean closure would be appropriate. For example, one commenter agreed with EPA that the risk-based corrective action process (RBCA) would be useful in determining whether waste removal is appropriate at the site.

EPA received relatively few comments on the specific standards for conducting clean closure. One commenter identified six criteria that should be included in any final regulation in order to allow a facility to have been deemed to have completed clean closure of a CCR surface impoundment and thereby avoid post-closure care. Some of the commenter's suggestions were comparable to requirements in the proposal. However the commenter also included requirements to ensure that adequate engineering controls were used to prevent contamination of soil and groundwater during excavation, and requirements for quarterly monitoring of shallow groundwater beneath the surface impoundment for a period of five years to demonstrate that no

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residual CCR was left in place. Finally, a number of commenters supported a provision that would allow the owner or operator to remove the deed notation required provided all CCR is removed from the site.

EPA did not propose to require clean closure nor to establish restrictions on the situations in which clean closure would be appropriate. As EPA acknowledged in the proposal, most facilities will likely not clean close their CCR units given the expense and difficulty of such an operation. Because clean closure is generally preferable from the standpoint of land re-use and redevelopment, EPA has explicitly identified this as an acceptable means of closing a CCR unit. However, both methods of closure (*i.e.,* clean closure and closure with waste in place) can be equally protective, provided they are conducted properly. Thus, consistent with the proposal, the final rule allows the owner or operator to determine whether clean closure or closure with the waste in place is appropriate for their particular unit. EPA agrees that the RBCA process, using recognized and generally accepted good engineering practices such as the ASTM Eco–RBCA process, can be a useful tool to evaluate whether waste removal is appropriate at the site. It is, however, not a necessary prerequisite.

EPA has adopted the provisions governing clean closure from the proposed rule with only one revision. The final provisions consist of two performance standards: First, the owner or operator must remove all CCR from the unit and decontaminate all areas affected by releases from the CCR landfill or surface impoundment. As part of meeting this performance standard, the final rule requires facility owners or operators to remove all wastes from the closing unit, and remove all liners contaminated with CCR waste and CCR waste leachate. The final rule also requires the owner or operator to remove and decontaminate all areas affected by releases from the CCR unit. This would require removal or decontamination of the underlying and surrounding soils and flushing, pumping, and/or treating the aquifer. The Agency interprets the term "soil" broadly to include both unsaturated soils and soils containing groundwater.

Second, the final rule specifies that closure has been completed when all CCR in the unit and any areas affected by releases from the CCR unit have been removed and groundwater monitoring demonstrates that all concentrations of the assessment monitoring constituents listed in appendix IV to part 257 do not exceed either statistically equivalent background levels or MCLs. This standard encompasses both saturated and unsaturated soils, as well as the groundwater. As part of attaining this standard, facility owners and operators will need to document that any contaminants left in the subsoils (*i.e.,* contaminated groundwater left in soils below the former landfill or impoundment) will not impact any environmental media including groundwater, surface water, or the atmosphere in excess of Agency-recommended limits or factors. Typically, any metals in these "subsoils" in excess of background levels are allowed to either naturally attenuate, or are removed by flushing. Once the facility has removed all of the assessment monitoring constituents listed in appendix IV down to background levels or MCLs the groundwater is considered to be "clean" and closure is complete.

EPA disagrees that specific provisions requiring the use of adequate engineering controls to prevent contamination of soil and groundwater during excavation are necessary to ensure that closure will be protective. To the extent that any contamination of soil or groundwater has occurred during CCR removal, this would constitute a release (or an "area affected by a release") from the CCR unit, and the final performance standard requires the facility to ensure that this has been removed before closure is deemed to be complete.

Contrary to the commenter's suggestion that quarterly monitoring for five years is necessary to demonstrate that no residual CCR was left in place, the rule requires a facility to document that all appendix IV concentrations are below MCL or background levels for two consecutive sampling events, using the statistical procedures in § 257.93(g). This is the same sampling required to demonstrate under the groundwater monitoring program that there is no longer a reason to suspect a source of contamination, and that consequently assessment monitoring can cease. EPA selected these provisions as the most factually analogous to the circumstances surrounding the clean closure of a CCR unit. Once a facility has removed the waste and any liner, the presumption is that the source of contamination has been removed as well. Although there may be site-specific factors that could support the need for a longer monitoring period, there is no factual basis to require a longer minimum period of sampling on a national basis.

This represents a change from the proposal. EPA proposed a performance standard that required decontamination to either any state established numeric cleanup levels for CCR constituents, or in the absence of state cleanup levels, the removal of metals to either statistically equivalent background levels, or to MCLs, or health-based numbers. This was taken directly from the current part 258 standards for MSWLFs. EPA has deleted both of these standards as inappropriate for these units.

The reference to state established clean up levels was inadvertently carried over from the existing part 258 regulations. As explained throughout this preamble, EPA is unable to rely on state programs to establish the specific standards under this rule; the record does not contain information on all state cleanup standards, and there is no mechanism for states to operate approved programs in lieu of federal programs.

EPA determined that the requirement to clean all soils to background levels was equally inappropriate. In practice, EPA does not routinely require complete removal of all contamination (that is, cleanup to 'background') from a closing unit even for hazardous waste units. Requiring CCR units to clean up soils to levels before the site was contaminated, would be more stringent than current hazardous waste policies. There is no basis in the current record to impose provisions for the remediation of CCR units that are more stringent than those imposed on hazardous wastes.

Upon completion, the unit is exempt from the groundwater monitoring and any other post-closure care requirements. In addition, the final rule adopts the proposal to allow the owner or operator to remove the deed notation required under § 257.102(i)(4), upon certification that clean closure has been completed. EPA proposed this option to create a further incentive for clean closure, and it is clear from the commenters, who uniformly supported this option, that it does so. Some commenters raised concern about the effect this option will have on state laws, which may not allow the deed notation to be removed. EPA notes that these criteria do not preempt state laws; to the extent state law requires the facility to retain a deed notation despite the completion of clean closure, those requirements will remain in place, notwithstanding this final rule.

3. Closure of a CCR Unit With CCR in Place

The proposed rule would have also allowed facilities to close a CCR unit by leaving the CCR in place and installing a final cover system. The final cover

system would have been required to be designed and constructed to a have a permeability less than or equal to the permeability of any bottom liner system or the natural subsoils present, or a permeability no greater than $1 \times 10^{-5}$ centimeters per second (cm/sec), whichever is less. The proposal would have also required an infiltration layer that contains a minimum of 18 inches of earthen material and an erosion layer containing a minimum of six inches of earthen material that is capable of sustaining native plant growth to help minimize erosion of the final cover. These proposed requirements were generally modeled after the performance standard and technical requirements contained in § 258.60 for MSWLFs. 75 FR 35208. EPA also proposed that the final cover system would have to be designed to minimize the disruption of the final cover through a design that accommodates settling and subsidence and provides for major slope stability to prevent the sloughing of the closed CCR unit over the long term. These last two criteria are based on existing requirements for interim status units under RCRA part 265 and MSHA requirements under 30 CFR part 77, subpart C, respectively.

As proposed, CCR surface impoundments would have been subject to an additional set of performance standards. The owner or operator of a CCR surface impoundment would have been required to either drain the CCR unit or solidify the remaining wastes. In addition, the owner or operator would have been required to stabilize the wastes to a bearing capacity to support the final cover. The proposed criteria would also have required that the final cover for all CCR units be designed to minimize the migration of liquids through the closed CCR surface impoundment over the long term; promote drainage, and accommodate settling and subsidence so that the final cover's integrity is maintained. Finally, closure of the CCR unit would also have been subject to the general performance standard that the probability of future impoundment of water, sediment, or slurry be precluded.

The Agency also proposed to allow owners or operators of CCR units to select an alternative final cover design. As proposed, the alternative final cover design would have required an infiltration layer that achieves an equivalent reduction in infiltration, and an erosion layer that would provide equivalent protection from wind and water erosion, as the infiltration and erosion layers specified for final covers described above. In addition, the proposed approach for alternative final cover designs would have also required certification by an independent registered engineer, notification being provided to the state that the alternative final cover design has been placed in the facility's operating record, and placement of the alternative final cover design on the owner or operator's publicly accessible Internet site.

a. Final Cover System Design

EPA received comments supporting the proposed approach, while other commenters opposed the proposed final cover system design requirements. One state commenter generally supported using the part 258 final cover design requirements as a general model for CCR units. This commenter also requested that the Agency clarify whether new CCR units would be required to install a composite final cover system given that it was proposed that new CCR units would be required to designed and constructed with a composite bottom liner. Another state indicated that its state regulations allow final cover designs similar to that proposed by EPA, although the state requires a 24 inch infiltration layer and a 12 inch erosion layer. Another commenter referenced current research showing that soil-only covers may not be effective in minimizing infiltration over the long term under certain climates. This commenter recommended that a geomembrane should be made a standard component of the cover system. Other commenters stated that the final cover system should be a composite system consisting of a synthetic component and a low permeability clay component. A state commenter offered that post-closure maintenance of composite cap system incorporating a geomembrane has been challenging in that state. Another commenter stated that a compacted clay liner should not be used as a final cover for landfills due to the potential for settlement cracking, desiccation cracking, and root and animal penetration. Instead, it was suggested that if a single barrier system is used, then a benefit-cost analysis favors a geomembrane, and if a composite barrier is to be used, a benefit-cost analysis favors a composite system of a geomembrane and geosynthetic clay liner.

The Agency also received many comments on the proposed approach to allow the use of alternative final cover systems. Most commenters supported allowing the use of alternative covers. One commenter stated that the use of geosynthetic clay liners in lieu of 18 inches of earthen material for the infiltration layer is a commonly accepted for cover systems for MSWLFs. This commenter also noted that that geosynthetic clay liners have documented permeability characteristics on the order of $1 \times 10^{-9}$ cm/sec. Another commenter supported allowing the use of alternative cover systems because a one-size-fits-all approach is not appropriate for final cover system designs. A state also offered that appropriately designed alternative final covers such as capillary barrier covers and evapotranspiration covers are being successfully used at facilities in the state.

After considering comments received regarding final covers, the Agency is essentially finalizing the approach in the proposed rule with minor revisions. The final rule allows owners or operators to use a final cover system consisting of an infiltration layer and an erosion layer, provided the infiltration layer has a permeability less than or equal to the bottom liner or natural subsoils. However, regardless of the bottom liner or natural subsoils present, the final cover must have a permeability no greater than $1 \times 10^{-5}$ cm/sec.

To address the commenters' concerns that the final cover system may not function effectively as designed over the long term under certain circumstances, the rule also includes a performance standard that any final cover system must meet. This standard is modeled after the closure performance standard applicable to interim status hazardous waste units under § 265.111. The final rule requires that any final cover system control, minimize or eliminate, to the maximum extent practicable, post-closure infiltration of liquids into the waste and releases of leachate (in addition to CCR or contaminated run-off) to the ground or surface waters. Thus, a facility must ensure that in designing a final cover for a CCR unit they account for any condition that may cause the final cover system not to perform as designed. This could include accounting for site conditions that may increase the likelihood that a cover would be susceptible to desiccation cracking or settlement cracking. Under this performance standard, if the cover system results in liquids infiltration or releases of leachate from the CCR unit, the final cover would not be an appropriate cover. The final rule requires the final cover system design to be certified by a qualified professional engineer that the design meets both the performance standard and cover system criteria.

The final rule does not require the use of composite final covers, such as a geomembrane underlain by a compacted soil infiltration layer. This is also the

case in situations for a CCR unit that is designed with a composite bottom liner or if the permeability of the soil underlying the unit is comparable to the permeability of a geomembrane. As EPA has concluded for municipal solid waste landfills, in certain site-specific situations it may be possible to construct an infiltration layer that achieves an equivalent reduction in infiltration without matching the permeability in the bottom liner material. 62 FR 40710.

Nonetheless, in certain locations, composite cover systems may be necessary to achieve the rule's performance standards. EPA acknowledges that under certain circumstances issues can arise with compacted clay barriers, particularly when used alone. These can include desiccation, freeze-thaw sensitivity, and distortion due to total and differential settlement of the underlying wastes. These issues can generally be addressed through proper maintenance of the cover system; and in fact the final rule requires as part of post-closure care that the owner or operator maintain the integrity and effectiveness of any final cover, including making repairs to the final cover to correct the effects of settlement, subsidence, erosion, or other events, and preventing run-on and run-off from eroding or otherwise damaging the final cover. Consequently, EPA is not mandating the installation of a composite liner system.

However, fewer problems are typically seen with the use of composite cover systems. And while ongoing oversight and proper maintenance is necessary to ensure the efficacy of any cover system, less effort is generally involved to ensure the continued performance of a composite cover system. EPA therefore generally recommends that facilities install a composite cover system, rather than a compacted clay barrier, as the composite system has often proven to be more effective (and cost effective) over the long term. For these reasons, EPA also anticipates that composite cover systems will be recommended in many circumstances by qualified professional engineers.

The final rule also allows the use of an alternative final cover. The rule requires that the alternative final cover must include infiltration and erosion layer that achieve equivalent performance as the minimum designs specified for final cover systems as discussed above. As discussed in the proposed rule, EPA included this provision to increase the flexibility for an owner or operator of a CCR unit to account for site-specific conditions. Moreover, these provisions will provide an opportunity to incorporate future technology improvements that would be missed if the rule required prescriptive design measures. In addition, these requirements would not supersede more stringent state requirements. Thus, if a state either has more prescriptive or more stringent standards in its state regulations applicable to CCR units, those state requirements would control any final cover system or alternative final cover system design.

While the rule provides the owner or operator flexibility in selecting the final cover for the unit, EPA remains concerned about the lack of guaranteed state oversight on final cover selection. A final cover system that does not perform as designed may result in unacceptable infiltration of water into the closed CCR unit that may lead to leachate and releases from the unit. To address this concern, as well as the concerns raised by commenters regarding the long-term performance of certain cover systems by providing further assurance that the final cover system will perform over the long term, EPA has deleted the proposed provision that would have allowed owners or operators to shorten the length of the post-closure care period. As discussed in Unit M.9 below, the final rule requires facilities to conduct post-closure care for all CCR units for 30 years.

b. Performance Standards When Leaving CCR in Place

EPA received no significant comments on the proposed performance standards. The Agency is therefore finalizing these requirements without revision from the proposal (although EPA has reorganized the final regulatory text for greater clarity). The performance standards are summarized below:

*i.* As discussed in the previous section, the CCR unit must be closed in a manner that will control, minimize or eliminate, to the maximum extent practicable, post-closure infiltration of liquids into the waste and releases of CCR, leachate, or contaminated run-off to the ground or surface waters.

*ii.* The CCR unit must be closed in a manner that will preclude the probability of future impoundment of water, sediment, or slurry.

*iii.* The CCR unit must be closed in a manner that will provide for major slope stability, which is discussed is Unit M.1 of this document for closure plans above.

*iv.* The CCR unit must be closed in a manner that will minimize the need for further maintenance of the unit.

*v.* The CCR unit must be closed in the shortest amount of time consistent with recognized and generally accepted good engineering practices. The Agency added this performance standard to be consistent with the final provisions applicable for the timeframes for initiating and completing the closure of CCR units.

4. Timeframes for Closure

The Agency proposed that closure of a CCR landfill or CCR surface impoundment must be initiated by the owner or operator no later than 30 days following the known final receipt of CCR. To address concerns about "inactive" or abandoned units, the proposed rule also provided that a CCR unit must initiate closure no later than one year after the most recent receipt of CCR if the CCR unit had remaining capacity and there was a reasonable likelihood that the CCR unit would receive additional CCR (*i.e.,* the rule would have forced the facility to close the CCR unit). See 77 FR at 35209 and proposed § 257.100(j). In addition, the proposed rule would have required an owner or operator to complete closure activities within 180 days of initiating closure. See proposed § 257.100(k). Thus, the maximum amount of time a facility would have had to initiate and complete closure of a CCR unit was seven months.

While the existing closure criteria for MSWLFs allow the Director of an approved State to grant time extensions for closure (both to initiate and to complete closure) if steps are taken to prevent threats to human health and the environment from the unclosed unit, EPA proposed not to include similar provisions for owners or operators of CCR units. At proposal, the Agency believed that extending the closure deadlines was inappropriate because, in the absence of an approved state program, the owner or operator could unilaterally decide to extend the time for closure of a CCR unit, without any basis, or oversight by a regulatory authority. 75 FR 35209.

EPA received numerous comments in response to the proposed deadlines under the subtitle D proposed approach. Industry and state commenters stated that the proposed deadlines to begin and complete closure activities (30 and 180 days, respectively) are technically impracticable and simply too short for the vast majority of CCR units, especially for CCR surface impoundments to complete closure. Commenters stated that a 30-day deadline to initiate closure activities may not be workable in situations such as when there are construction

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limitations due to seasonal or climatic conditions, and should not be required in circumstances when a coal-fired generating unit is temporarily idled (*e.g.,* maintenance related outages or an outage corresponding with a CCR handling system conversion). Regarding the amount of time needed to close a unit, numerous commenters noted that it would be impossible to properly complete closure activities within the proposed 180 days at most CCR surface impoundments due to the length of time needed to dewater an impoundment and stabilize the wastes prior to constructing the final cover system. For example, commenters pointed out that dewatering of a surface impoundment alone can take several years to complete because impoundments can be hundreds of acres in size. One commenter provided information related to an ongoing CCR surface impoundment closure where the dewatering and ash stabilizing phases of closure took two years to complete. Commenters also stated that because a large number of CCR units will have to be closed during roughly the same timeframe, facilities may not be able to obtain the necessary specialized personnel, equipment, and materials (*e.g.,* clay or fill material, liner materials) to close multiple units simultaneously. This issue may be further complicated in locations where multiple facilities are competing for the same limited resources. Commenters further argued that adopting the same closure deadlines applicable to MSWLFs is not appropriate given differences in size, design, and operation (*e.g.,* CCR surface impoundments contain large volumes of water, MSWLFs typically close each component cell when it reaches its disposal capacity). As a result of these concerns, commenters recommended that EPA extend the deadlines both to commence and complete closure activities. The majority of the these commenters, however, urged EPA not to establish specific deadlines for closure and instead require facilities to close a CCR unit consistent with a closure plan approved by a state, or developed and certified by a qualified professional, such as a professional engineer.

In a subsequent NODA, the Agency solicited additional public comment on several different options to address these concerns. 78 FR at 46944–46. With respect to the deadline to initiate closure, EPA presented several examples of routine and legitimate circumstances in which CCR units would not receive CCR for periods longer than one year, even though the facility intended to continue to use the unit. For example, EPA discussed circumstances in which the facility alternates between two surface impoundments, only one of which is operational at a time. Once the impoundment has reached capacity, the facility dewaters the unit, and begins to send CCR to the second impoundment. Once the unit is dewatered, the CCR is excavated and disposed in an adjacent landfill. The time to fill these units has varied over the years as demand has fluctuated, but a typical time to fill a unit with CCR is two years, perhaps longer, during which the other unit is "idle," in that it does not "receive CCR," but it remains operational.

The Agency also solicited comment on a revised approach to the deadline to initiate closure. The approach entailed establishing a rebuttable presumption that if the CCR unit has not received waste within a particular period of time (*e.g.,* 18–24 months), the CCR unit would be considered inactive and unit closure would be required to begin within a specified time. However, if the facility could substantiate that there was a reasonable likelihood that the CCR unit would again receive CCR in the future and also was able to document certain findings, the owner or operator would not need to immediately commence closure of the CCR unit. In the NODA, EPA discussed several examples of situations that could support a demonstration that immediate closure of the CCR unit was not necessary. One example was if an owner or operator could document that a CCR unit had been dedicated to a temporarily idled coal-fired generating unit and there was a reasonable likelihood that CCRs would be disposed in the CCR unit once the coal-fired generating unit resumed operation. Another situation presented was a CCR unit dedicated to a coal-fired generating unit that was not burning coal at the time (*e.g.,* electricity was being generated with other fuels such as natural gas), but the facility needed the CCR unit following resumption of coal burning. A final example involved normal facility operations that include periods during which the CCR unit does not receive CCR for extended periods (*e.g.,* the alternating use of two CCR surface impoundments discussed above). As part of this approach, the Agency solicited comment on whether to limit the length of time an owner or operator can maintain an idle CCR unit.

With respect to the deadline for completing closure, EPA acknowledged in the NODA that different deadlines, at least for the larger CCR units, were warranted. Information that the Agency has obtained throughout the rulemaking confirmed commenters' claims that the timeframes originally proposed to complete closure of CCR surface impoundments will be practicably infeasible for the larger impoundments. However, the Agency cautioned that any ultimate timeframe provided in the rule that would be practicable for the largest CCR units would be far too long to justify as timeframes for closure of the smaller impoundments. EPA explained that it intended to examine available closure plans for CCR surface impoundments to determine whether there are consistent timeframes or other factors that EPA could adopt as part of the regulations. EPA specifically identified two closure plans of CCR units that were scheduled to close as a possible source of useful information. These plans projected that closure would take multiple years to complete for modestly-sized CCR surface impoundments (*i.e.,* less than 50 acres).

a. Deadlines To Initiate Closure

In response to the NODA, most utility commenters stated that the time to initiate closure should be tied to reasonable triggers that account for the diverse uses of CCR surface impoundments and CCR landfills. In particular, these commenters recommended that closure not be initiated for an idled CCR unit if the CCR unit was expected to receive additional waste in the future, whether CCR or any other waste the unit may be authorized to manage. These commenters also supported the scenarios EPA described in the NODA as examples of legitimate situations that could warrant delaying the immediate closure of a CCR unit. Many of these commenters generally agreed that the rebuttable presumption alternative discussed in the NODA could be an appropriate approach for closure, in particular for CCR units not covered by a state-approved operating plan, provided the regulatory approach would be implemented in a manner that did not restrict other legitimate uses of the CCR unit. Many of these commenters also asserted that a limit on the length of time a CCR unit can remain idle is not practical because the owner or operator will not be able to predict with any degree of certainty how long a CCR unit will be idled. Several of these commenters also urged EPA to specify in the final rule what EPA intended by the phrase "initiation of closure;" that is, that EPA define the activities or actions the owner or operator must take by the deadlines specified in the rule.

A trade organization and other commenters warned that strict restraints on the initiation (and completion) of

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closure of CCR units would pre-empt opportunities for reclaiming CCR from these CCR units for beneficial use of CCR. These commenters recommended that the final rule create meaningful incentives for the beneficial use of CCR already in CCR units which will become unavailable to reclamation once a final cover system is put in place. For example, one commenter suggested that an incentive could be deferring deadlines for closure of a CCR unit if an owner or operator reduces its net tonnage by a set amount, such as 10,000 tons per year, if the CCR is beneficially used. EPA also received comments from several states that generally supported the rebuttable presumption concept. One state supported a longer rebuttable presumption time period of three years that could be extended if approved by the state on a case-by-case basis.

After consideration of all of the public comments, the Agency is adopting an approach that largely mirrors the approach outlined in the NODA. Closure of a CCR unit is triggered in one of three ways. The first is upon the known final receipt of waste (CCR or otherwise), or when an owner or operator removes the known final volume of CCR from the CCR unit for the purpose of beneficial use of CCR. Under these scenarios, the final rule requires an owner or operator to commence closure of the CCR unit within 30 days of such known final receipt or known final volume removal, whichever date is later.

The second way closure can be triggered relates to "idled" CCR units. This applies to situations in which the CCR unit has remaining disposal, treatment, or storage capacity, or there has been a temporary pause in the removal activities of CCR from the CCR unit. In these situations, the rule establishes a presumption that the owner or operator must initiate closure of the CCR unit no later than two years after the most recent receipt of CCR or any non-CCR waste stream, or no later than two years after the most recent date that CCR was removed from the CCR unit for the purpose of beneficial use, whichever date is later. The rule, however, provides procedures for an owner or operator of the CCR unit to rebut this presumption and obtain additional time, provided the owner or operator can make the prescribed demonstrations.

The final way closure is triggered is when a CCR unit fails to meet certain of the technical criteria. Specifically, an owner or operator may be compelled to close a CCR unit in the following circumstances: (1) If the CCR unit has been sited inappropriately; *i.e.,* cannot meet the applicable location criteria; (2) if an unlined CCR surface impoundment is found to contaminate groundwater in excess of a groundwater protection standard; or (3) if a CCR surface impoundment cannot demonstrate the minimum factors of safety regarding structural integrity of the CCR unit. When closure is triggered under these circumstances, the owner or operator must initiate closure of the CCR unit within six months. Each of these is discussed in more detail below.

i. "Known Final Receipt" of CCR

Several commenters suggested that the rule not link the deadlines to initiate closure solely to when a CCR unit ceases to receive CCR. Many of these commenters provided information that CCR units also serve functions other than managing CCR, including the management of other wastes or water treatment. Thus, while there are periods of time that certain CCR units will receive both CCR and non-CCR wastes, there are also other times when the same CCR unit will only receive non-CCR wastes or perform other forms of active waste management in the unit, *e.g.,* specific water treatment functions. EPA agrees that these are legitimate waste management activities, and EPA is aware of no risks that would warrant cessation of such activities simply because the unit is no longer receiving CCR. Therefore, in response to these comments, the final rule no longer requires closure based solely upon the receipt of CCR. Instead, the final rule requires closure to be initiated after the CCR unit ceases to receive any waste or waste stream into the CCR unit. See § 257.102(e)(1) and (e)(2) in the rule.

The Agency also agrees with those commenters that supported delaying the commencement of closure of a CCR unit if substantial quantities of CCR are removed from the CCR unit for the beneficial use of the waste. This could include, for example, removal of CCR from a CCR unit followed by its use as a partial replacement for Portland cement. As discussed in Unit IV.B of this preamble, EPA has identified significant benefits from reducing the disposal volumes of CCR in CCR landfills and CCR surface impoundments, including reduced risks associated with the practice of CCR disposal, benefits from reducing the need to mine and process virgin materials, and energy and greenhouse gas benefits. EPA finds these potential benefits compelling and is therefore revising the closure requirements in the rule to accommodate the removal and beneficial use of CCR. EPA has therefore revised the rule to provide that closure of an otherwise idled CCR unit is not immediately triggered, as long as the owner or operator is removing substantial quantities of CCR from the unit. However, once removal of CCR for beneficial use is no longer taking place, the rule would require the owner or operator to initiate closure of the CCR unit. See § 257.102(e)(1) and (e)(2) in the rule.

After considering comments received regarding the specific timeframe by which closure must be initiated following known final receipt of wastes, the Agency is finalizing the 30 day timeframe from the proposed rule. Several commenters expressed concern that 30 days is too short because it does not account for the potential that weather or seasonal concerns may interfere or cause substantial delay. The Agency acknowledges that weather or seasonal effects can delay certain activities, but disagrees that the rule provision needs to be revised to account for those. This provision does not require that specific actions or activities must be initiated during this 30-day period. For example, the rule does not require the installation of the final cover system (or the commencement of removal of CCR from the CCR unit) necessarily begin within this 30-day period. Instead, the provision is more flexible; the owner or operator can initiate closure by taking other actions necessary to implement the closure plan that are not weather or seasonal dependent, such as turning off pumps supporting sluice lines or taking any steps necessary to comply with any state or other agency standards that are a prerequisite to initiating closure. Provided the owner or operator has started to take the measures to implement the closure plan that can be feasibly undertaken, the facility will have complied with this requirement.

The 30-day period remains equally appropriate under the wider provision that allows closure to be triggered either by the known final receipt of all wastes in the unit, or upon the known final volume removal of CCR for beneficial use of CCR. There are no facts unique to these circumstances that would necessitate an extension beyond the 30 day timeframe. Furthermore, as the terms "known final receipt" and "known final volume removal" suggest, the owner or operator has made the determination to cease managing waste in the CCR unit, or to cease removing CCR from the CCR unit for beneficial use purposes. This will likely occur in situations where the CCR unit is reaching its disposal capacity (or treatment capacity when the CCR unit is receiving non-CCR waste streams) or the

owner or operator intends to close the CCR unit for other purposes (*e.g.*, the closing of a CCR surface impoundment following conversion to dry handling of CCR). Given that these situations can generally be anticipated and planned for in advance, EPA is not aware of circumstances that would prevent owners or operators from at least commencing closure within this 30-day period. In summary, the owner or operator must commence closure of the CCR unit with 30 days of known final receipt of CCR or any non-CCR waste stream, or within 30 days of known final removal of CCR for beneficial use, whichever date is later.

ii. Temporarily Idled Units

This situation involves CCR units with remaining CCR disposal or storage capacity (or treatment capacity for non-CCR waste streams) that may sit idle for extended periods of time (*e.g.*, potentially years at a time); however, the owner or operator intends to continue to maintain the idled unit to receive CCR or non-CCR waste streams in the future. EPA proposed that these CCR units could remain idle for up to one year, but that closure of the CCR unit would have to be initiated no later than one year after the most recent receipt of CCRs. See 75 FR 35252 (proposed § 257.100(j)). The majority of commenters claimed that one year was too short and would require the premature closure of CCR units that would be needed in the future. In response to these comments and new information documenting examples of legitimate circumstances in which CCR units were idled for more than one year, EPA solicited comment on a revised approach to establish longer timeframes to initiate closure for temporarily idled CCR units. As discussed previously, this approach entailed establishing a rebuttable presumption that if the CCR unit has not received waste within a specified period of time (*i.e.*, 18 months to two years), the CCR unit would be considered inactive and closure of the CCR unit would be required. However, this time could be extended beyond the 18 months or two years if the facility could substantiate certain findings. See 78 FR at 46945.

After considering comments received, the Agency is essentially finalizing the approach presented in the 2013 NODA. Specifically, in situations where the CCR unit has remaining disposal or storage capacity (or treatment capacity for non-CCR wastestreams) and there is a reasonable likelihood that the CCR unit will receive additional CCR or non-CCR waste in the future, the final rule allows the owner or operator to keep the CCR unit available for use for up to two years. However, if the CCR unit has not received CCR or any non-CCR waste within two years of the last receipt of CCR or any non-CCR waste, whichever date is later, the rule requires closure of the CCR unit unless the owner or operator can document that additional time is necessary to accommodate routine operations and legitimate waste management activities.

The Agency agrees that it is not necessary to require closure of temporarily idled CCR units after one year. Information in the record documents numerous examples of legitimate circumstances in which CCR units were idled for more than one year. In most of the examples provided CCR units are temporarily idled for periods that can last more than one year, but typically use of the CCR units resumes within approximately two years. Based on this information EPA has concluded that a two year timeframe before presumptively requiring closure of a CCR unit would be more consistent with current practice, and is better supported by the available information.

This same information documented that there can be situations in which a CCR unit is idled for longer periods of time (*e.g.*, a coal-fired boiler may be idled for years during which another fossil fuel is burned (*e.g.*, natural gas), and the CCR unit will be needed when the utility returns to coal burning. In order to obtain additional time beyond two years, the owner or operator must document in writing both that the CCR unit has remaining disposal or storage capacity and the facts that support a conclusion that there is a reasonable likelihood that the CCR unit will accept CCR or non-CCR waste in the foreseeable future. The facility would need to substantiate those findings, including the specific reasons the owner or operator believes "that there is a reasonable likelihood that CCR will be disposed in the waste disposal unit." These findings would need to be certified by the owner or operator of the CCR unit.

The rule identifies examples of specific scenarios that would support a determination that there is a continuing need for the unit to support future waste management activities (*e.g.*, that the CCR will resume receiving CCR or non-CCR waste in the future). These are intended to be illustrative rather than an exclusive list; there may well be additional circumstances in which routine operations or legitimate waste management practices would support the necessary determination. The particular situations identified in the rule generally match those discussed in the NODA or reflect situations identified in public comments. Specifically, the rule identifies four particular circumstances: (1) Normal plant operations include periods during which the CCR unit does not receive wastes (CCR or non-CCR waste streams). This may include the alternating use between one CCR unit that receives CCR while dewatering or removing CCR from a second unit. (2) The CCR unit is dedicated to a coal-fired boiler unit that is temporarily idled (*i.e.*, CCR is not being generated) and there is a reasonable likelihood that the coal-fired boiler will resume operations in the future. (3) The CCR unit is dedicated to an operating coal-fired boiler (*i.e.*, CCR is being generated); however, no CCR is being placed in the CCR unit because the CCR is being entirely diverted to beneficial uses, but there is a reasonable likelihood that the CCR unit will again be used in the foreseeable future. (4) The CCR unit currently receives only non-CCR waste streams and those non-CCR waste streams are not generated for an extended period of time, but there is a reasonable likelihood that the CCR unit will again receive non-CCR waste streams in the future. As noted, a facility must substantiate these findings; it is not sufficient to merely repeat the words of the regulation and conclude that additional time is warranted.

The final rule allows an owner or operator to obtain additional two-year time extensions for as long as the owner or operator continues to be able to provide a factual basis to justify the need for additional time via a written demonstration. Because these idled units must continue to comply with all applicable technical requirements, including those for groundwater monitoring, corrective action, and structural stability, a fixed or definitive limit on the amount of time that a CCR unit can sit idle is not necessary.

In addition, the Agency agrees that the final rule should better define the actions or activities that constitute "initiation of closure" of a CCR unit. A clear definition will assist in the implementation and understanding of the rule. Commenters suggested a number of actions or activities, any one of which would be sufficient to show that closure of the CCR unit has been initiated. Examples provided by the commenters included the removal of CCR sluice lines; beginning the necessary permitting processes (*i.e.*, submitting a completed permit application); turning off pumps supporting the sluice lines; preparing a bid for contractors; or procuring capping materials such as clay or top soil.

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The final rule specifies that closure has been initiated when the owner or operator takes two actions. The first action is that the owner or operator must have permanently ceased placing CCR and non-CCR waste streams in the CCR unit. As suggested by commenters, permanent removal of CCR sluice lines or inactivation of the pumping system supporting the sluicing operation would be evidence that placement of CCR and non-CCR waste streams has ceased. The second action is that the owner or operator must have taken steps to implement the written closure plan required by the rule. This second action would include submitting a completed application for any required state or agency permit or permit modification in order to implement closure of the CCR unit, or taking any steps necessary to comply with any state or other agency standards or regulations that are a prerequisite to initiating or completing the closure of the CCR unit. Once the owner or operator has completed both of these actions, closure of the CCR unit has been initiated for purposes of this rule. See § 257.102(e)(3) in this rule.

iii. Closure for Cause

Finally, the Agency is clarifying that the closure initiation timeframes specified above—the 30 day period for known final receipt or known final volume removal and the 2 year period for temporarily idled CCR units—do not apply to closures initiated for cause. As discussed elsewhere in the preamble, the final rule requires certain CCR surface impoundments and CCR landfills to close. The situations include: Unlined CCR surface impoundments whose groundwater monitoring shows an exceedance of a groundwater protection standard; existing CCR surface impoundments that do not comply with the location criteria; CCR surface impoundments that are not designed and operated to achieve minimum safety factors; and existing CCR landfills that do not comply with the location criteria for unstable areas. In these situations, the final rule specifies that the owner or operator must initiate closure activities within six months of making the relevant determination that the CCR unit must close.

b. Deadlines To Complete Closure

In response to the August 2013 NODA, many utility commenters stated that the time period to complete closure must be sufficiently flexible to account for the inherent uncertainties in predicting a closure schedule. These commenters pointed to potentially innumerable complications and circumstances beyond the control of the owner or operator that render it nearly impossible to predict with precision when the closure of a CCR unit will be completed. These commenters also believe it is impractical and unrealistic for the rule to subject the closure of CCR units to any type of fixed regulatory structure. They maintained their position from the proposed rule that it would be impossible to properly complete closure of most CCR surface impoundments within 180 days. Their recommendation is to allow closure timeframes to be governed by the a state-approved closure process, which would include the owner or operator developing and submitting a closure plan to the state and mechanisms for the state to verify and enforce compliance with all closure requirements, including the closure plan. Under this approach, the owner or operator's compliance with the requirements of the state-approved closure process (including following the closure plan, completing mitigation, etc.) would represent compliance with this rule's closure requirements. For CCR units not subject to a state-approved closure process, these commenters recommended that the owner or operator should demonstrate compliance with the CCR closure requirements by submitting a closure plan to the state that is certified by an independent professional engineer. In this case, because there is not direct state oversight and administration of the closure process, the timelines in the closure plan could be subject to a modified set of tiered timeframes for completing closure, provided owners or operators could demonstrate that more time is needed to close the unit on a case-by-case basis.[122] These commenters also opposed any closure approach with firm and inflexible timeframes because no single factor (*e.g.,* the acreage of the CCR unit or the volume of CCR in the unit) is determinative in all instances of how long it will take to complete closure of the CCR unit. Commenters also cautioned that pre-closure closure plans (and the closure schedules contained therein) may not be an actual reflection of the time it will take to close the unit due to unforeseen or variable conditions. Finally, these commenters also generally opposed the idea discussed in the NODA of petitioning the Agency for a site-specific rule to vary from a generally applicable deadline.

Many commenters described the numerous factors that could affect timeframes for closure of a CCR unit. Most comments were specific to CCR surface impoundments where closures are typically more complex as compared to CCR landfills due to the presence of water in impoundments. Factors most often cited by the commenters that may affect the time required to close a CCR unit included: (1) The size and volume of CCR in the unit; (2) the geotechnical characteristics of the CCR; (3) the type or design of the surface impoundment (*i.e.,* diked, incised, valley fill, and side hill); (4) the need to coordinate or obtain approvals from state permitting officials; (5) the availability of qualified engineers, contractors, and materials since closing a CCR unit is a specialized activity, especially given that many units may be required to close simultaneously; (6) climate and weather that can affect dewatering operations and the length of a construction season; (7) the time needed to obtain replacement disposal capacity for a closing unit that would ensure ongoing facility operations; and (8) dam safety considerations during closure. Many of commenters identified that the dewatering process (an early necessary step in the closure process) as being a site-specific issue, as the time that will be needed to dewater an impoundment can vary considerably depending on the type of CCR unit, the volume of CCR in unit, and the geotechnical properties of the CCR. Several commenters also cited that closure times for some CCR units will require substantial volumes of fill material to properly grade a closing surface impoundment to facilitate positive drainage from the closed unit. These commenters provided estimates on the volumes of fill material needed and showed that the earthmoving aspect of this step alone can take many years to complete in some cases.

Several state commenters generally supported the tiered closure alternative discussed in the NODA. However, these commenters urged EPA to include provisions in the rule to provide flexibility for closing units to demonstrate the need for additional time on a case-by-case basis.

i. Timeframes for Completing Closure

In the August 2013 NODA the Agency solicited comment on ways to establish categories of timeframes that would adequately account for the various factors that can affect the amount of

[122] The tiered timeframes for completing closure could be based on the size of the CCR unit (after obtaining necessary state and local approvals): (1) Within 3 years for an impoundment with an area less than 20 acres; (2) Within five years for an impoundment between 20 and 50 acres; (3) Within 8 years for an impoundment between 50 and 75 acres; (4) Within 10 years for an impoundment with an area of 75 acres or more; and (5) Within 180 days for a landfill. Under this approach, the owner or operator could demonstrate the need for additional time to close the CCR unit.

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time needed to properly close a CCR surface impoundment. One approach discussed in the NODA was called the "tiered approach" that was based on comments received in response to the proposed rule. Under that approach, the final rule would establish fixed timeframes to complete closure that varied depending on the size of the impoundment (*i.e.,* surface area acreage). The Agency stated in the NODA that the concept of a tiered approach was appealing; however, the precise basis for the distinctions (*i.e.,* unit size cutoffs) and timeframes were not clear. EPA further explained its concern that factors other than size (*e.g.,* climate, geography, unit configuration) would also appear to be relevant, and that any timeframes should account for those other factors. EPA encouraged commenters interested in supporting a tiered approach to provide the rationale and data to support any suggested categories of timeframes. 78 FR 46946. Most commenters opposed the tiered approach by itself (*i.e.,* an approach without an accompanying process by which an owner or operator could obtain additional time due to site-specific circumstances) because they felt there simply are too many factors that can affect closure timeframes. These commenters concluded that basing closure timeframes on a subset of factors would not be appropriate. As one commenter noted, a 20 acre impoundment 10 feet deep can likely be dewatered and closed more quickly than a 20 acre impoundment 30 feet deep.

After considering comments and information available on closure timeframes, EPA has concluded that there are insufficient data and information to adopt the kind of tiered approach discussed in the NODA. EPA is convinced that the available information does not support an approach that would establish fixed and definitive timeframes for closure, based on a select subset of factors that distinguish between surface impoundments (*e.g.,* a 50 acre diked impoundment holding 500 acre-feet of CCR with a hydraulic conductivity of $1 \times 10^{-5}$ centimeters per second located in a state in the southwest with a permitting program would be required to close in four and one-half years, while a 50 acre cross valley impoundment holding 1,500 acre-feet of CCR with a hydraulic conductivity of $1 \times 10^{-6}$ centimeters per second located in a state in the upper midwest with a permitting program would be required to close in seven years, etc.). While information is available for surface impoundments on certain factors, such as the size and type of the unit and geographic information, the Agency has little to no data for a number of other key factors. For example, EPA has no information on the geotechnical properties of the CCR that can affect the time needed to dewater a unit, the volumes of clays, soils, and other materials that will be needed for closure, and information on the time needed to obtain state approvals (in accordance with state CCR programs) related to closure of a unit.

In discussing the tiered approach EPA noted that commenters had suggested that the largest CCR surface impoundments (*i.e.,* those having a surface area greater than 75 acres) should be subject to a site-specific deadline to complete closure. In the NODA, the Agency explained that a site-specific deadline may not be practicable unless the rule were to establish a "variance" process as part of the rule. 78 FR 46946. Under a variance approach, EPA would establish a specific deadline (*e.g.,* closure must be completed no later than five years from the date closure activities are initiated), but would allow facilities to petition EPA for a site-specific rule to establish an alternate deadline. In response to the NODA, some commenters expressed interest in such an approach, but other commenters found the approach not practicable since each owner or operator would need to petition the Agency for a site-specific rule. Some commenters believed that a site-specific rule process, which would necessarily involve a notice and comment process, would be an unwieldy process leading to unnecessary delays. The Agency agrees that this is also not a practical alternative to establish timeframes to complete closure.

Recognizing the numerous factors that can affect the amount of time needed to close an impoundment, many commenters suggested EPA not establish any type of fixed regulatory deadline for closure. Instead, these commenters recommended that the rule allow closure timeframes to be governed by a state-approved closure process. Under this process suggested by commenters, an adequate state-approved closure process would include one where the owner or operator developing and submitting a closure plan to the state and mechanisms for the state to verify and enforce compliance with all closure requirements, including the closure plan. Under the commenter's recommendation, compliance with the requirements of the state-approved closure process would not be compliance with the closure requirements of this rule. As discussed elsewhere in this preamble, under subtitle D of RCRA, the Agency cannot rely on the existence of a state permitting authority to implement the subtitle D requirements.

Some other commenters suggested EPA not establish any type of fixed regulatory deadline for closure in the rule, and instead rely on the closure plan developed and certified by a professional engineer. The Agency disagrees that this approach would meet the protectiveness standard of RCRA section 4004(a). CCR units present significant risks, and it is critical that facilities complete closure expeditiously—particularly those that are closing because they are structurally unsound or are contaminating groundwater. To be able to determine that the rule will be protective, the final rule must limit the discretion of individual facilities, many of whom may have significant incentives for delay, and avoid the potential for abuse. Moreover, in contrast to corrective action, where EPA was truly unable to establish an outer limit on the necessary timeframes—including even a presumptive outer bound—closures, while complex, do not vary to the same degree as site remediation actions. Consequently, as discussed later in this section, the available data were sufficient to support the establishment of definitive timeframes.

Most commenters, however, were generally supportive of an approach that would establish timeframes for closure, whether in a tiered-like approach (*i.e.,* timeframes for closure based on one or more characteristics of the unit) or under a "rebuttable presumption" approach, so long as the rule would provide the owner or operator a process or procedures to demonstrate the need for additional time. As explained in the NODA, such an approach could be implemented by establishing a presumption that facilities complete closure within a specified timeframe, such as five years, unless the facility could document that closure is not feasible to complete within the presumptive timeframe.

After consideration of all of the public comments, EPA is adopting an approach that takes elements from two of the alternatives discussed in the NODA: The concept of tiered timeframes based primarily on the size of the surface impoundment, and the concept of a rebuttable presumption. The final rule establishes a presumption that the owner or operator must complete the closure of a CCR surface impoundment within five years of initiating closure activities. For CCR landfills the presumption is that the owner or

operator must complete closure within six months of initiating closure activities. The rule, however, provides procedures for an owner or operator to rebut either presumption and obtain additional time, provided the owner or operator can make the prescribed demonstrations. For CCR surface impoundments, the amount of additional time beyond the five years varies based on the size (using surface area acreage of the CCR unit as the surrogate of size) of the unit. For impoundments 40 acres or smaller, the maximum time extension is two years. For impoundments greater than 40 acres, the maximum time extension is five two-year extensions (ten years) and the owner or operator must substantiate the factual circumstances demonstrating the need for each two year extension. For a CCR landfill, the amount of additional time beyond the six months does not vary according to the size of the landfill, rather the maximum time extension is two one-year extensions (two years) for any CCR landfill. The owner or operator must substantiate the factual circumstances demonstrating the need for each one-year extension.

ii. CCR Surface Impoundment Timeframes

To develop these timeframes the Agency began by identifying the period of time in which most surface impoundments could feasibly complete closure. EPA intended this period of time to serve as the basis for the rebuttable presumption of the rule. As EPA recognized in the NODA, a timeframe that would be feasible for the largest units would grant more time than could be justified to complete the closure of smaller units. The closure of CCR units, and particularly the closure of CCR units that are compelled to close because they fail to comply with the rule's requirements (*e.g.,* are structurally unstable or are contaminating groundwater), needs to occur as expeditiously as is feasible. While these units (and particularly the larger CCR surface impoundments) are in the process of closing, they continue to present risks to human health and the environment. On the other hand a presumptive time period that is feasible for a small percentage of units would simply result in a greater number of facilities that would need to obtain time extensions. It is well established that the law cannot compel actions that are physically impossible, "*lex non cogit ad impossibilia,*" and it is incumbent on EPA to develop a regulation that does not in essence establish such a standard.

The available information shows that CCR surface impoundments can vary in size by orders of magnitude (*i.e.,* from less than one acre to nearly 1,000 acres). EPA evaluated the information on the size distribution of CCR surface impoundments in its database of survey results from EPA's 2009 Information Request.[123] Through this effort, EPA received a substantial amount of factual information from 240 facilities covering 676 surface impoundments, including surface area information on over 650 impoundments. The database of survey responses shows that the median surface impoundment is approximately 14 acres in size, 75 percent of impoundments are 50 acres or smaller, 80 percent of impoundments are 66 acres or smaller, and 90 percent of impoundments are 111 acres or smaller.

Available information on actual and projected timeframes needed to close CCR surface impoundments of varying sizes (using surface area as the surrogate for size) is summarized below. Much of this information came from public comments from utilities. The largest CCR surface impoundment in this data set that has actually completed closure is a 40-acre unit that closed over a period of approximately five years (*i.e.,* the surface impoundment at PPL Corporation's Martins Creek Power Plant).[124] This facility closed with waste in place, and included installation of a final cover system. According to the facility, this CCR unit ceased receiving wastewater in January 2008, and the closure work began with dewatering the unit and preparing the revised closure plan and permit modification applications. Installation of the final cover, in addition to final soil grading and seeding of the unit was completed in spring 2012. By early 2013, all remaining closure actions were completed and state regulators issued final approvals in July 2013. EPA gave substantial weight to this information because (1) it was a CCR surface impoundment—the units of greatest relevance to the issue at hand; (2) the closure was recently completed, and so would accurately reflect current and available engineering practices; and (3) the facility actually completed closure of the unit. See EPA–HQ–RCRA–2012–0028–0103 and EPA–HQ–RCRA–2012–0028–0113.

As another example, American Electric Power (AEP) provided some information on the recent closure of a CCR surface impoundment in 2013. This 21-acre unit had been inactive for several years and was closed over the course of two construction seasons. The impoundment was closed by leaving CCR in place and installing a composite cap, in addition to the installation of hydraulic appurtenances to control the design storm events. See EPA–HQ–RCRA–2012–0028–0067.

Cleco Corporation provided planned closure timeframes contained in existing permits for its CCR surface impoundments. For three of its CCR surface impoundments, which in aggregate totaled 66 acres, Cleco Corporation estimated that it could take approximately one year to complete closure, which would be accomplished by leaving CCR in place and installing a final cover system. Cleco Corporation also estimated that it would take approximately nine months to complete closure of two additional CCR surface impoundments, with an aggregate acreage of 5.5 acres, by removing CCR from the CCR units, (*i.e.,* clean closure of the units). Information on the size of any of the five CCR units was not provided, which complicates the Agency's ability to assess the closure of any of the individual CCR units. In addition, the time period appears to begin when dewatering operations are initiated and the comments do not discuss how much time may be needed to obtain any necessary approvals from the state prior to commencing closure activities. See EPA–HQ–RCRA–2012–0028–0106.

Similarly, Xcel Energy stated in its comments to the NODA that it closed four CCR surface impoundments at its Northern States Power of Minnesota's Minnesota Valley Plant by removing all of their contents. See EPA–HQ–RCRA–2012–0028–0079. While the commenter did not provide any information on the time needed to close the four CCR units, other information available to the Agency indicated that closure took place sometime after May 2009 and was completed prior to September 2013. Based on information obtained from Xcel Energy in response to EPA's request for information from May 2009, the four CCR units at the Minnesota Valley Plant each have a surface area less than one acre. In addition, the response to the information request showed that one CCR surface impoundment was nearly full of ash, a second was more than half full, and the final two CCR units were less than one quarter full.

In the August 2013 NODA, the Agency solicited comment on a draft plan to close two CCR surface

[123] More information on EPA's Information Request, including a data base of survey responses, can be accessed at *http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/surveys/index.htm.*

[124] EPA included information on the planned closure of this CCR surface impoundment in the NODA. 78 FR 46945. The closure plan estimated that the closure process would take approximately three years to complete.

impoundments at Santee Cooper's Grainger Generating Station in South Carolina. 78 FR 46945. The plan estimated that closure of the two CCR units, approximately 42 and 39 acres in surface area, could be accomplished during a three year period. This original estimate was based on closing the unit with waste in place and installing a final cover. However, Santee Cooper has since amended its draft plan and is now pursuing closure by removal of CCR and transport off-site for either disposal or beneficial use.[125] The revised draft envisions the complete removal of CCR from both CCR units and also one foot of underlying soil beneath the units. In total, the draft closure plan estimates that approximately 1.3 million cubic yards of CCR and underlying soil will be removed from both units—approximately 900,000 cubic yards from one unit and 400,000 cubic yards from the second—over a period of six to ten years.

The Florida Electric Power Coordinating Group (FCG) claimed that, based on FGC member experience, closing a 30 acre CCR surface impoundment is expected to take approximately two years to complete, but provided no additional information or details. See EPA–HQ–RCRA–2012–0028–0064.

The Utility Solid Waste Activities Group (USWAG) provided another projected closure schedule for a 20 acre CCR surface impoundment operated by Luminant. This facility was in the process of closing the unit when the comments were prepared. The schedule estimated that completion of all closure activities, would take approximately 45 months (3 years, 9 months) to complete. However, the commenter also states that, when complete, the "full closure period will take approximately 84 months (seven years) due to the unique circumstances of that closure." No other information was provided on this closure to explain the "unique circumstances" that warrant such an extended period of time. See EPA–HQ–RCRA–2012–0028–0113.

There is other information in these data that indicates that larger impoundments may be able to complete closure within approximately the same timeframes as smaller units. For example, the data included the projected closure of a 100-acre CCR surface impoundment over a four and one-half year period, which seems to indicate that larger units may be able to close in approximately the same period of time. However, the Agency gave substantially less weight to this information for a number of reasons. Most critically, this information merely demonstrated projected timeframes for CCR surface impoundments, not actual timeframes that had been achieved. In addition, for some of these data, it was unclear whether the circumstances that allowed for completion within this timeframe were generally applicable to the majority of CCR surface impoundments. In one instance, the commenter noted that the time to complete closure was shorter than would normally be expected because the impoundment was being closed well before it reached full capacity and because water in the impoundment could be pumped into an adjacent impoundment. The commenter also noted that the impoundment had been built with a leachate collection system to facilitate dewatering at closure. See EPA–HQ–RCRA–2012–0028–0113.

Moreover, the majority of commenters claimed that it would take substantially longer than five years to close the largest impoundments. For example, USWAG stated that one of its members obtained "approval for a closure plan for a 343-acre surface impoundment that provided for a twelve-year closure period to ensure adequate time to complete dewatering of the impoundment, assure the stability of the dewatered CCRs, and uniformly construct the slope of the final cover materials." No other information was provided on this closure example. See EPA–HQ–RCRA–2009–0640–10483. USWAG also provided information on the closure of the CCR surface impoundment at First Energy's Little Blue Run Disposal Area. This 950 acre surface impoundment, which is the largest CCR surface impoundment in the country, has a projected closure period of 15 years.

Similarly, to illustrate the time required simply for earthmoving operations to close a large CCR surface impoundment (in their example, 350 acres), Duke Energy Corporation estimated that the time needed in the schedule to deliver and place the necessary volume of materials for construction of the final cover and the sub-base to the cover system could take between nine and 12 years. This estimate is based on the need for approximately 10 to 11 million cubic yards of fill to construct and shape the sub-base of the final cover and the cover system itself that would require nearly 500,000 truckloads to deliver. See EPA–HQ–RCRA–2012–0028–0095.[126]

Collectively, this information formed the basis for the five year presumptive default. As noted the median size of CCR surface impoundments is approximately 14 acres, and 75 percent of impoundments are 50 acres or smaller. The information presented by the utilities documents that impoundments as large as 66 acres under normal circumstances can close within two to three years. EPA therefore expects that most, if not all, units should be able to complete closure within five years. For all but the very largest units, this timeframe would even accommodate potential delays caused by weather or any other unpredictable variables. This is clearly demonstrated by the examples presented by public comments, and by the recent example of the 40-acre CCR surface impoundment in Martins Creek that closed within five years.

EPA also notes that five years is the timeframe Congress mandated for the completion of open dumps to close or upgrade. While the closure times apply generally to all units—both those whose closure is mandated by this final rule and those that close because the facility decides to do so—the statutory directive provides further support for EPA's decision.

But as many commenters stated, initial estimates can and often do vary from actual closure times due to unforeseen or variable conditions. EPA acknowledges that a host of variables can, and frequently do, delay closure activities, such that the initial time estimates to complete closure of the unit are ultimately exceeded. For example, the 40 acre impoundment at Martins Creek Power Plant discussed above was initially scheduled in its closure plan to be completed within three years; however, closure ultimately took five years to complete. The additional two

[125] "Amended Closure Plan Wastewater Ash Ponds, Grainger Generating Station, Conway, South Carolina," January 2014.

[126] EPA also received information from Consumers Energy Company on the closure of three former fly ash surface impoundments at the JR Whiting plant. These surface impoundments (combined) totaled approximately 52 acres and are scheduled to be closed with a final cover over an approximately 12-year period. The commenter claimed that the extended time for closure "was necessary to allow dewatering and the filling of numerous voids, but principally to allow the generation of fly ash to allow the placement of structurally placed, low permeability ash to provide minimal required slopes for closure and to serve as the select layer for the flexible membrane liner." See EPA–HQ–RCRA–2012–0028–0068. Information on the individual size of any of the three CCR units was not provided in the comments, which complicates any assessment of the time needed to complete closure of any single CCR unit. Because the facility appears to be continuing to use the unit to actively manage waste, EPA does not consider this to be representative of a typical closure process.

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years was due to the need to obtain approval of a modified closure plan from the state, as well as modifications to three permits, in addition to obtaining other local planning approvals. Further time was also needed to accommodate the public notice and comment processes for several of the permits and approvals.

EPA recognizes that there are a number of unpredictable or variable conditions that can affect the time needed to close a CCR unit and that those conditions are not within the control of the owner or operator. For example, some states require review and approval of a closure plan prior to initiating of closure activities. See, for example, 25 Pa. Code sections 288.292(b) and 289.311(b) for CCR landfills and CCR surface impoundments, respectively. Another commenter noted that in Illinois, permits from several different authorities may need to be obtained to commence closure, including the Illinois Department of Natural Resources, the U.S. Army Corps of Engineers, and the U.S. Fish and Wildlife Services.

Climate and weather can also impact the time needed to complete closure. For example, an unusually wet or short construction season can result in schedule delays; one commenter noted that in certain regions of the Midwest, it is possible for as much as 40 inches of rain to fall in a given season.

To account for these conditions, a substantial majority of commenters requested that the final rule include the potential for time extensions, and several specifically referenced the need for a "force majeure" provision. One commenter also recommended that a "force majeure" clause specifically include delays caused by court order (*i.e.,* appeals of permits issued by state agencies causing judgments in court). Another commenter provided an example of a "force majeure" provision that could serve as a model:

> An extension shall be granted for any scheduled activity delayed by an event of force majeure which shall mean any event arising from causes beyond the control of the owner that causes a delay in or prevents the performance of any of the conditions under this rule including but not limited to: acts of God, fire, war, insurrection, civil disturbance, explosion; adverse weather conditions that could not be reasonably anticipated causing unusual delay in transportation and/or field work activities; restraint by court order or order of public authority; inability to obtain, after exercise of reasonable diligence and timely submittal of all applicable applications, any necessary authorizations, approvals, permits, or licenses due to action or inaction of any governmental agency or authority; and delays caused by compliance with applicable statutes or regulations governing contracting, procurement or acquisition procedures, despite the exercise of reasonable diligence by representatives of the owner.
>
> Events which are not force majeure include by example, but are not limited to, unanticipated or increased costs of performance, changed economic circumstances, normal precipitation events, or failure by the owner to exercise due diligence in obtaining governmental permits or performing any other requirement of this rule or any procedure necessary to provide performance pursuant to the provisions of this rule.

EPA agrees that the rule should include procedures to obtain extensions of time to complete closure of the unit, based on the complexity of the activity. As previously noted, the law, including a regulation, cannot compel the impossible. However, because the record demonstrates that most units, even the larger units, can close within that five year timeframe, the rule establishes a high threshold to obtain additional time. To account for those instances of true physical impossibility, the rule limits extensions to circumstances in which the owner or operator can demonstrate that the additional time is needed due to factors that are truly beyond the facility's control—*i.e.,* could fairly be characterized as an example of "force majeure." To obtain additional time, the owner or operator of the CCR unit must document in writing the exact reasons why additional time is needed. The regulation specifies that such reasons could include: (1) Complications stemming from the climate and weather, such as unusual amounts of precipitation or a significantly shortened construction season; (2) the time required to dewater a surface impoundment due to the volume of CCR contained in the CCR unit or the geotechnical characteristics of the CCR in the unit; (3) the geology and terrain surrounding the CCR unit will affect the amount of material needed to close the CCR unit; or (4) the time required or delays caused by the need to obtain State permits and/or to comply with other State requirements. These findings would need to be certified by the owner or operator of the unit, as well as by a qualified professional engineer.

The final rule limits the amount of time that closure can be extended based on the size of the CCR unit. Specifically, the rule allows CCR surface impoundments 40 acres or smaller a time extension of up to two years, while CCR surface impoundments larger than 40 acres can obtain up to five two-year extensions. The 40 acre size demarcation is based on the available information showing that surface impoundments of 40 acres or smaller routinely have either completed closure or are projected to be able to complete closure within a timeframe shorter than five years. EPA expects that facilities will account for all potential delays that can reasonably be foreseen in planning their closure activities, and that this is feasible within this five year timeframe. Consequently the final rule restricts facilities with units of this size to a single extension to account for truly exception circumstances (*e.g.,* Acts of God).

The Agency also recognizes that there is increased uncertainty for CCR surface impoundments larger than 40 acres. First, while available information documents that some CCR surface impoundments larger than 40 acres can be closed within this same five year period, the Agency has other information indicating that closure of units larger than 40 acres can be expected to take much longer than five years. For example, the largest surface impoundment in the country is approximately 950 acres and is scheduled to cease receiving CCR by December 31, 2016 and commence closure in 2017. The facility's projected closure period is 15 years. However, EPA currently has no data (anecdotal or otherwise) on the actual timeframes in which a surface impoundment of that size has completed closure. Given that closure for the largest of surface impoundments could reasonably be expected to take more than five years to complete, the Agency has concluded that surface impoundments larger than 40 acres need to be provided with the possibility of additional time extensions beyond the two years provided to impoundments less than 40 acres. Based on available information, in particular the current estimates of the time needed to close the largest unit in the country, the rule authorizes a facility to obtain a maximum of five time extensions, totaling as much as ten years in two year increments to close a CCR surface impoundment greater than 40 acres. However, the owner or operator must substantiate the factual circumstances demonstrating the need for each two-year extension.

Several commenters also urged EPA to specify in the final rule what EPA intended by the phrase "completion of closure;" and to define the activities or actions the owner or operator must complete to satisfy the closure requirements. For purposes of this rule, closure of a CCR unit is complete when the unit meets all of the requirements of this rule and the owner or operator

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obtains certification from a qualified professional engineer verifying that closure has indeed been completed, consistent with all of the performance standards in the rule. While EPA recognizes that under some state programs closure is not considered complete until the owner or operator receives certification from the state, this is not a prerequisite to completion of closure under these federal rules.

iii. Closure Timeframes for CCR Landfills

Similar to the approach for CCR surface impoundments, EPA recognizes that there can be unforeseen and extraordinary circumstances that warrant additional time to close a CCR landfill. Accordingly, the rule adopts procedures analogous to those for CCR surface impoundments that allow the owner or operator to obtain additional time to complete the closure of a CCR landfill, provided the owner or operator can make the prescribed demonstrations. However, the amount of additional time the facility can obtain beyond the presumptive six month timeframe does not depend on the size of the landfill; rather the maximum time extension is two one-year extensions (two years) for any CCR landfill. As with the procedures for CCR surface impoundments, the owner or operator must substantiate the factual circumstances demonstrating the need for each one-year extension.

EPA developed this timeframe based on its review of the available information in the record regarding the timeframes for completing the closure of CCR landfills, some of which is summarized below. Additional information may also be found in the comment response document.

In response to the August 2013 NODA, Nebraska Public Power District (NPPD) provided information documenting that it completed closure of a 10 acre CCR landfill within 180 days after the final volume of fly ash and bottom ash was placed in the CCR landfill. Closure was accomplished by leaving CCR in place and installing a final cover system. NPPD's comments do not indicate what year closure of this CCR landfill was completed. See EPA–HQ–RCRA–2012–0028–0076.

The Florida Electric Power Coordinating Group (FCG) stated in its comments that FCG member experience with CCR landfill closure has "demonstrated the need for a period of time greater than 180 days to complete closure activities." However, the commenter did not provide any information indicating how long such closures actually took, nor any information to substantiate their claim. See EPA–HQ–RCRA–2012–0028–0064.

Overall, the closure of CCR landfills is less complex than the closure of CCR surface impoundments. Portions of the CCR landfills that reach final grade can be closed as other areas of the CCR landfill continue to receive CCR, which is typically not possible at CCR surface impoundments. Nor does the owner or operator need to dewater the unit, which appears to be the aspect of closure most likely to be a source of unanticipated circumstances. Finally, there is substantially less uncertainty with respect to the timeframes to complete the closure of CCR landfills, which are not all that different (in this respect) than landfills containing other forms of solid or hazardous waste. EPA therefore has greater confidence that a fixed period of two years will be adequate to account for the vast majority of circumstances.

c. Alternative Closure Requirements

The Agency is finalizing alternative closure requirements in two narrow circumstances for a CCR landfill or CCR surface impoundment that would otherwise have to cease receiving CCR and close, consistent with the requirements of § 257.101(a), (b)(1), or (d). The first is where the owner or operator can certify that CCR must continue to be managed in that CCR unit due to the absence of both on-site and off-site alternative disposal capacity. § 257.103(a). The second is where the owner or operator of a facility certifies that the facility will cease operation of the coal-fired boilers no later than the dates specified in the rule, but lacks alternative disposal capacity in the interim. § 257.103(b). Under either of these alternatives, CCR units may continue to receive CCR under the specified conditions explained below. In addition, under either alternative, the owner or operator must continue to comply with all other requirements of the rule, including the requirement to conduct any necessary corrective action.

*1. No alternative CCR disposal capacity (§ 257.103(a)).*

The Agency recognizes that the circumstance may arise where a facility's only disposal capacity, both on-site and off-site, is in a CCR unit that has triggered the closure requirements in § 257.101(a), (b)(1), or (d). As a result, the facility may be faced with either violating the closure requirements in § 257.101 by continuing to place CCR in a unit that is required to close, or having to cease generating power at that facility because there is no place in which to dispose of the resulting waste. For example, while it is possible to transport dry ash off-site to alternate disposal facility that simply is not feasible for wet-generated CCR. Nor can facilities immediately convert to dry handling systems. As noted previously, the law cannot compel actions that are physically impossible, and it is incumbent on EPA to develop a regulation that does not in essence establish such a standard.

Should a facility choose to comply with the regulation and stop generating power, there would be significant risks to human health that would arise if a community would be left without power for an extended period of time. As information in the record demonstrates, obtaining alternative capacity can sometimes require a substantial amount of time (*e.g.,* if the facility needs to construct alternative capacity, including potentially the need to locate an alternative site or purchase additional property). EPA recognizes that there are also significant risks to human health and the environment, as demonstrated throughout this preamble, from a leaking or improperly sited CCR unit, and that these risks justify requiring those units to either retrofit to meet the federal criteria established in the final rule or close. EPA also acknowledges that in the interim period while the owner or operator seeks to obtain additional capacity, the risks associated with the continued use of these units will be significant. However, the Agency believes that the risks to the wider community from the disruption of power over the short-term outweigh the risks associated with the increased groundwater contamination from continued use of these units. This conclusion is further buttressed by the fact that during this interim period the risks associated with allowing these units to continue to receive CCR are mitigated by all of the other requirements of the rule with which the facility must continue to comply, including the requirements to continue groundwater monitoring and corrective action.

Under § 257.103(a)(1), a CCR unit that would otherwise be required to cease receiving CCR under § 257.101(a), (b)(1), or (d), may continue to receive CCR provided the owner or operator certifies that the CCR generated at that facility must continue to be managed in that unit due to the absence of alternative disposal capacity both on-site and off-site. The rule also requires the owner or operator to document this claim, and the claim must be based on the real absence of an alternative and not justified based on the costs or inconvenience of alternative disposal capacity. § 257.103(a)(1)(i). The owner

or operator must also remain in compliance with all other requirements of this rule, including the requirement to take any necessary corrective action. § 257.103(a)(1)(ii). Because this alternative is only available as long as the absence of disposal capacity exists, the owner or operator must document its efforts to obtain additional capacity. If any additional capacity is identified, the owner or operator must arrange to use it as soon as is feasible. § 257.103(a)(1)(iii). The owner or operator is also required to prepare an annual progress report documenting the continued absence of disposal capacity and must also document the progress made toward developing alternative capacity. § 257.103(a)(1)(iv).

Once alternative disposal capacity is available, the CCR unit must cease receiving CCR and must initiate closure following the timeframes in § 257.102(e) and (f). Finally, if the owner or operator has not identified alternative capacity within five years after the initial certification the CCR unit subject to this section must cease receiving CCR and must initiate closure following the timeframes in § 257.102(e) and (f). As discussed elsewhere in this preamble, several commenters provided information to document the length of time needed to obtain additional capacity. Based on this information, the five year timeframe provided for under this alternative is expected to provide sufficient time to obtain alternative disposal capacity and to avoid the consequences of a forced immediate closure of a power plant.

*2. Permanent cessation of a coal-fired boiler by a date certain. (§ 257.103(b)).*

Under this provision, the Agency addresses the circumstance where a facility's only disposal capacity, both on-site and off-site, is in a CCR unit that has triggered the closure requirements in § 257.101(a), (b)(1), or (d), but the owner or operator of coal-fired power plant has decided to permanently cease operation of that plant within one of two timeframes specified in the regulation. For the same reasons discussed immediately above, EPA has concluded that the provisions of § 257.103(b) represent the most reasonable balance between the competing risks.

Additionally, EPA anticipates that some owners or operators will decide to permanently cease operation of a coal-fired power plant in response to the combined effects of new and/or existing statutory or regulatory requirements promulgated under the Clean Air Act and under the Clean Water Act (*e.g.* the proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category. See 78 FR 34442, in combination with market dynamics. As discussed earlier in this preamble, RCRA section 1006(b) directs EPA to integrate the provisions of RCRA for purposes of administration and enforcement and to avoid duplication, to the maximum extent practicable, with the appropriate provisions of other EPA statutes, including the CAA and the CWA. As noted earlier, section 1006(b) conditions EPA's authority to reduce or eliminate RCRA requirements on the Agency's ability to demonstrate that the integration meets RCRA's protectiveness mandate (42 U.S.C. 6005(b)(1)). *See Chemical Waste Management* v. *EPA,* 976 F.2d 2, 23, 25 (D.C. Cir. 1992). The provisions of § 257.103(b) are fully consistent with the direction in section 1006(b) to account for the provisions of other EPA statutes which may lead an owner or operator to close a coal-fired power plant.

EPA has also concluded that the provisions of § 257.103(b) meet RCRA's protectiveness mandate. As stated above, EPA recognizes that there are long-term risks to human health and the environment, as demonstrated throughout this preamble, from a leaking CCR unit and those risks justify requiring those units to either meet the federal criteria established in this rule or close. However, the risks associated with allowing these units to continue to receive CCR are mitigated by the requirement that the facility must comply with all other requirements of the rule, including initiating groundwater monitoring and corrective action where necessary. And a critical factor is that facilities that choose to rely on this alternative will be required to *complete* closure of their disposal unit in an expedited timeframe. Thus, the risks from these units will be fully addressed sooner. Consequently, while over the short term the risks will be higher, overall, the risks will be at least equivalent to, or potentially lower than if the CCR unit had closed in accordance with the normal closure timeframes.

Under § 257.103(b)(1), a CCR unit that would otherwise be required to cease receiving CCR under § 257.101(a), (b)(1), or (d), may continue to receive CCR provided the owner or operator of the facility certifies that the facility will cease operation of the coal-fired boilers within the timeframes specified in paragraphs (b)(2) through (b)(4) and that the CCR generated at that facility (before the plant ceases to operate) must continue to be managed in that unit due to the absence of alternative disposal capacity both on-site and off-site. The rule also requires the owner or operator to document the facts that support this claim. The regulation specifies that the claim must be based on the real absence of alternative disposal capacity, and not justified based on the costs or inconvenience of alternative disposal capacity. § 257.103(b)(1)(i). The owner or operator must also remain in compliance with all other requirements of this rule, including the requirement to take any necessary corrective action. § 257.103(b)(1)(ii). The owner or operator is also required to prepare an annual progress report documenting the continued absence of disposal capacity and must also document the progress made toward the closing of the coal-fired boiler. § 257.103(b)(1)(iii).

Under § 257.103(b)(1), the owner or operator does not need to demonstrate any efforts to develop alternative capacity because of the impending closure of the power plant itself.

Consistent with the general timeframes provided for the closure of CCR surface impoundments, EPA has established different timeframes based on the size of the CCR unit. Under § 257.103(b)(2), where the disposal unit is a CCR surface impoundment 40 acres or smaller in size, the coal-fired boiler must cease operation and the disposal unit must have completed closure within 8.5 years of the publication date of the rule. Where the disposal unit is a CCR surface impoundment larger than 40 acres in size, the coal-fired boiler must cease operation and the disposal unit must have completed closure within 13.5 years of the publication date of the rule. § 257.103(b)(3). Finally, under § 257.103(b)(4), where the disposal unit is a CCR landfill, the coal-fired boiler must cease operation and the disposal unit must have completed closure within 6 years of the publication date of the rule. These timeframes were selected to ensure that closure of these units will be completed in a measurably shorter timeframe, and that overall the risks will be lower, or at least equivalent to, the level of risk that would be achieved under the rule's "standard" closure provisions.

5. Notation on the Deed to Property

The proposed rule would have required, following closure of the CCR unit, the owner or operator to record a notation on the deed or some other instrument normally examined during a title search. This notation would notify any potential purchaser in perpetuity that the property has been used as a CCR landfill or CCR surface impoundment and that use of the land is restricted under the rule's post-closure care provisions. After the

notation was completed, the proposed rule would have required the owner or operator to notify the state that the notation has been recorded and a copy has been placed in the facility's operating record and on its publicly accessible internet site. In addition, the Agency solicited public comment on adding a provision to the rule to allow removal of the deed notation once all CCR are removed from the CCR unit, and notification is provided to the state of this action. The EPA solicited comment on this potential approach as a way to create a further incentive for clean closure of the facility. 75 FR at 35208–09. The proposal further encouraged commenters who are interested in supporting such an option to suggest alternatives to state oversight to provide for facility accountability.

EPA received few public comments on the proposed requirement to record a deed notation to the property (or some other instrument that is normally examined during title search). One commenter provided general support for the proposed requirement to record a deed notation to the property. Another commenter urged EPA to ensure that any deed notation requirements should not interfere or conflict with existing state property laws that provide for environmental covenants.

EPA did receive several comments in response to the Agency's solicitation of comment on adding a provision to the rule to allow removal of the deed notation when all CCR are removed from the facility, and notification is provided to the state of this action. One commenter supported the addition of this provision, stating that the licensure requirements of the Professional Engineer provide an assurance of integrity because the Professional Engineer would be required to verify that closure has been completed in accordance with the closure plan. This commenter also stated that it would be sufficient to allow removal of a deed notation upon an application to the state agency supported by a declaration of a licensed professional, subject to state agency review and approval. Another commenter supported providing the incentive for clean closure and allowing the facility to demonstrate the "cleanliness of the closure." The commenter also recommended that the information provided by the facility should be followed by a review from an independent third party with knowledge of the industry and associated environmental issues.

After considering comments, the final rule requires an owner or operator to record a notation on the deed or some other instrument normally examined during a title search. This notation notifies any potential purchaser in perpetuity that the property has been used as a CCR landfill or CCR surface impoundment and that use of the land is restricted under the rule's post-closure care provisions. See § 257.102(i). In response to the commenter that urged EPA to ensure that any deed notation requirements should not interfere or conflict with existing state property laws, the Agency has no information that the proposed requirement would create such a conflict. In addition, the commenter did not provide any information or suggest that EPA's proposed approach would actually interfere or conflict with existing state property laws. Therefore, the Agency is finalizing the deed notation requirement as proposed.

In addition, regarding the Agency's solicitation of comment on adding a provision to the rule to allow removal of the deed notation when all CCR are removed from the facility, as discussed in Unit VI.M.2 of this preamble, the final rule adopts the proposal to allow the owner or operator to remove the deed notation required under § 257.102(i)(4), upon certification that clean closure has been completed. The rationale for this decision is discussed in that unit of the preamble.

6. Notification of Intent To Close and Certification of Closure Completion

The Agency proposed to require owners or operators to notify the state that a notice of intent to close a CCR unit has been placed in the facility's operating record and on the publicly accessible internet site. This notification had to be completed prior to beginning closure of the CCR unit. Following closure of a CCR unit, the proposed rule would also have required the owner or operator to obtain a certification from an independent registered professional engineer verifying that closure has been completed in accordance with the written closure plan. As proposed, this certification would be placed in the facility's operating record and on the publicly accessible Internet site.

The Agency received no public comments on the proposed requirements to develop a notification of intent to close or the certification of completion of closure. Therefore, the Agency is finalizing these requirements as proposed. See § 257.102(g) and (h).

7. Post-Closure Care Plan

The Agency proposed to require that the owners or operators of CCR landfills and CCR surface impoundments prepare a written post-closure care plan describing how the CCR unit would be maintained after closure. See proposed § 257.101(c). The proposal also identified the minimum information necessary to include in the post-closure care plan. This information included: (1) A description of the monitoring and maintenance activities for the CCR unit and the frequency at which these activities would be performed; (2) the name, address, and telephone number of the person or office to contact about the facility during the post-closure care period; and (3) a description of the planned uses of the property during the post-closure care period.

The proposed rule further provided that the post-closure use of the property shall not disturb the integrity of the final cover, liner(s), or any other components of the containment system, or the function of the post-closure monitoring systems unless necessary to comply with the requirements of the rule. The proposal would have allowed a disturbance if the owner or operator of the CCR unit demonstrated that disturbance of the final cover, liner, or other component of the containment system, including any removal of CCR, would not increase the potential threat to human health or the environment. A professional engineer would have been required to certify such a demonstration.

The Agency received no significant comments on the proposed post-closure care requirements. The Agency's responses to these comments are addressed in the closure comment response document, which is available in the rulemaking docket. Therefore, the Agency is finalizing these requirements substantially as proposed. See § 257.102(g) and (h).

8. Post-Closure Care Activities

Following closure of a CCR landfill or CCR surface impoundment, EPA proposed that the owner or operator would be required to conduct post-closure care of the closed unit. At a minimum, the proposal would have required the owner or operator to conduct at least the following: (1) Maintain the integrity and effectiveness of any final cover, including making repairs to the final cover to correct the effects of settlement, subsidence, erosion, or other events, and preventing run-on and run-off from eroding or otherwise damaging the final cover; (2) maintain the integrity and effectiveness of the leachate collection and removal system and operating the leachate collection and removal system in accordance with applicable requirements under the design criteria for such systems; and (3) maintain the groundwater monitoring system in

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accordance with applicable requirements under the groundwater monitoring and corrective action rule provisions.

EPA received few public comments on the proposed activities to conduct during the post-closure care period. These commenters were supportive of the activities and specifically urged the rule to require the monitoring of groundwater throughout the post-closure care period. The Agency received no comments opposing the proposed post-closure care activities. Therefore, EPA is finalizing the same post-closure care activities in this rule. See § 257.104(b). In addition, consistent with the proposal, the rule clarifies that certain CCR units are not subject to these post-closure care activities. Specifically, owners or operators that elect to close a CCR unit by removing CCR (*i.e.,* clean close the CCR unit) are not subject to any post-closure care requirements. See § 257.104(a)(2) and Unit M.2 of this preamble. In addition, owners or operators of inactive CCR surface impoundments that elect to complete closure of the unit within 30 months of the rule's effective date are not subject to any post-closure care requirements. See § 257.104(a)(3).

9. Length of Post-Closure Care Period

The Agency proposed that the owner or operator of a CCR unit conduct post-closure care for 30 years. EPA also proposed to allow utilities to conduct post-closure care for a decreased length of time if the owner or operator demonstrates that the reduced period is sufficient to protect human health and the environment. The owner or operator would have been required to have this demonstration certified by a professional engineer, in addition to complying with all of the notification and posting requirements under the proposed rule. The proposed rule would also have allowed an increase in the post-closure care period if the owner or operator of the CCR unit determined that it is necessary to protect human health and the environment. EPA also recognized in the proposed rule that state oversight can be critical to ensure that post-closure care is conducted for the length of time necessary to protect human health and the environment; however the Agency also recognized that there is no set length of time for post-closure care that will be appropriate for all possible sites, and all possible conditions. Therefore, EPA solicited comment on alternative methods to account for different conditions, yet still provide methods of oversight to assure facility accountability.

Some commenters supported the proposed approach because it provided flexibility to increase or decrease the post-closure care period of 30 years. EPA also received comments from a number of states documenting the current state requirements; some states require a post-closure care period of less than 30 years, some require 30 years, and one state currently requires 40 years for CCR units. Other commenters opposed the shortening of the 30-year period without state involvement and approval.

After considering public comments, and in a departure from the proposed rule, the Agency is requiring that post-closure care be conducted for a minimum of 30 years. EPA is making this change due to the lack of guaranteed state oversight for this rule. The Agency has concluded that providing the owner or operator the flexibility to shorten the post-closure care period is no longer appropriate, particularly given the flexibility being provided for the selection of a final cover system or alternative final cover system. As discussed in Unit M.3 above, the information available to the Agency supports the need to proceed cautiously. By not allowing the post-closure care period to be shortened, EPA better ensures that the final cover system will be properly maintained. In addition, a mandatory 30 year period ensures that if problems do arise with respect to a final cover system, the groundwater monitoring and corrective action provisions of the rule will detect and address any releases from the CCR unit, at least during the post-closure care period.

10. Notification of Completion of Post-Closure Care Period

The Agency proposed to require owners or operators of CCR units to notify the state that a notice of completion of the post-closure care period has been placed in the facility's operating record and on the publicly accessible Internet site. The proposed approach would have required the owner or operator to obtain a certification from an independent registered professional engineer verifying that post-closure care has been completed in accordance with the written post-closure care plan.

The Agency received no public comments on the proposed requirement to develop a notification of completion of the post-closure care period. Therefore, the Agency is finalizing these requirements as proposed. See § 257.104(e).

*N. Recordkeeping, Notification and Posting of Information to the Internet*

In response to EPA's lack of authority to require a state permit program or to oversee state programs, EPA has sought to enhance the protectiveness of the regulatory requirements by providing for state and public notifications of the third party certifications, as well as requiring a robust set of other information that documents the decisions made or actions taken to comply with the technical requirements of the rule. Consistent with the proposed rule, owners or operators of CCR units are required to document how the various provisions of the rule have been met by placing information (*e.g.,* plans, records, notifications, reports) in the operating record and providing notification of these actions to the State Director/or appropriate Tribal authority. The owner or operator is also required to establish and maintain a publicly accessible Internet site that posts documentation that has, in many instances, also been entered into the operating record. The owner or operator is required to maintain a copy of the current Emergency Action Plan, the current fugitive dust control plan, and the current written closure plan as long as the facility remains active. EPA believes that the establishment and maintenance of this information in both the operating record and on a publicly accessible Internet site is appropriate so as to allow states and citizens access to all of the information necessary to show that the rule has been implemented in accordance with the regulatory requirements.

With regard to the specific recordkeeping and reporting requirements outlined in the proposal, the Agency received very little comment. Commenters were primarily concerned not with the specific recordkeeping requirements but rather how the recordkeeping requirements aligned with the overall approach of the RCRA subtitle D regulatory scheme. These comments and the Agency's responses are discussed in Unit V of this preamble.

The combined mechanisms of recordkeeping, notifications, and maintaining a publicly accessible Internet site will serve to provide interested parties with the information necessary to determine whether the owner or operator is implementing and is operating in accordance with the requirements of the rule. As stated in the proposal and reiterated here, EPA believes that it cannot conclude that the RCRA subtitle D regulations will ensure there is no reasonable probability of

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adverse effects on health or the environment, unless there are mechanisms for states and citizens to monitor the situation, such as when groundwater monitoring shows exceedances above the groundwater protection standard specified in the rule, so they can determine when intervention is appropriate. EPA also believes that the recordkeeping and notification requirements will minimize the danger of owners or operators abusing the self-implementing system being established in this rule through increased transparency and by facilitating the citizen suit enforcement provisions applicable to the rule.

In contrast to the proposed rule, the Agency has identified for ease of implementation each recordkeeping, notification and Internet posting required in this rule. The proceeding section provides a summary of the requirements for each reporting mechanism.

1. Recordkeeping Requirements

This rule requires the owner or operator of a CCR landfill or CCR surface impoundment and any lateral expansion to maintain files of all required information (*e.g.,* demonstrations, plans, notifications, and reports) that supports the implementation of this rule in an operating record located at the facility. Each file must be maintained in the operating record for a period of at least five years following submittal of the file into the operating record. In certain instances, however, files must be maintained until the CCR unit completes closure. For example, the initial and periodic structural stability assessments as required under section § 257.73(d) and § 257.74(d) must be maintained for five years consistent with the timeframe for periodic reassessments. Whereas, information on the construction of a CCR surface impoundment must be maintained until the CCR unit completes closure (see 257.73(c) and 257.102.) These timeframes are generally consistent with the timeframes required for maintaining hazardous waste compliance records under subtitle C of RCRA and with the timeframes outlined in the proposed subtitle C option for the regulation of CCR. (See specifically 40 CFR 264.73 and 265.73.)

Owners or operators with more than one CCR unit may elect to consolidate all files into one operating record provided that each unit is identified and files for that unit are maintained separately in different sections of the operating record. The owner or operator of the CCR unit must place files documenting compliance with the location restrictions; design criteria; operating criteria; groundwater monitoring and corrective action; closure and post closure care, into the operating record, with the specific documentation requirements found in § 257.105. In the development of this final rule, the Agency has included in the regulatory language a comprehensive listing of each recordkeeping and notification required by the rule. The Agency anticipates that this effort will facilitate owners or operators efforts in complying with the reporting provisions of the rule, and will provide other interested parties with a guide to the reporting provisions of the rule.

2. Notification Requirements

As previously discussed, owners or operators are required to notify State Directors and/or the appropriate Tribal authority when specific documentation has been placed in the operating record and on the owner or operator's publicly accessible Web site. In most instances these notifications must be certified by a qualified professional engineer and may, in certain instances will be accompanied with additional information and or data supporting the notification. For example under § 257.106(f)(1), within 60 days of commencing construction of a new CCR unit, a notification of the availability of the design criteria specified under § 257.105(f)(1) or (f)(3) in the operating record and on the owner or operator's publicly accessible Internet site. If however, the owner or operator of the CCR units elects to install an alternative composite liner, the owner or operator must also submit to the State Director and/or appropriate Tribal authority a copy of the alternative composite liner design which has been certified by a qualified professional engineer.

Notification requirements can be found in § 257.106, and are required for location criteria, design criteria, operating criteria, groundwater monitoring and corrective action and closure and post closure care.

3. Publicly Accessible Internet Site Requirements

The Agency is finalizing, as proposed a requirement for owners and operators of any CCR unit to establish and maintain a publicly accessible Internet site, titled "CCR Rule Compliance Data and Information." As with the operating record, owners or operators that maintain multiple CCR units may elect to use one Internet site in order to comply with these requirements, provided that the Web site clearly and distinctly identifies information from each of the CCR units by name and location. Unless provided otherwise in the rule, information posted to the Internet site must be available for a period no less than three years from the initial posting date. Posting of information must be completed no later than 30 days from submittal of the information to the operating record. This timeframe is consistent with the notification requirements of the rule. As with the other criteria in this section, Internet postings are required for various elements identified in the following sections: Location restrictions; design criteria; operating criteria; groundwater monitoring and corrective action; closure and post closure care. These requirements are enforceable by citizen suits.

## VII. Summary of Major Differences Between the Proposed and Final Rules

The basic regulatory framework outlined in the proposed rule under the subtitle D option, is being adopted in this final rule for the regulation of CCR landfills and CCR surface impoundments and any lateral expansion. However, as discussed in Unit VI of this document, the Agency has made a number of revisions to several of the provisions in the proposed rule, including (1) the timeframes for closure; (2) locations restrictions—placement above the uppermost aquifer; (3) the use of an alternative composite liner design; (4) revisions to align the structural stability criteria with the experience and data generated by the Assessment Program; and (5) air criteria. These changes have been made in response to public comments and additional information collected and analyses conducted by EPA in the course of responding to those comments. These are discussed in greater detail below. Under the proposed rule, all new CCR landfills and all CCR surface impoundments that had not completed closure would be required to retrofit to a composite liner or close within five years. However, after reviewing comments and further evaluation, the Agency has concluded that this regulatory approach was unnecessary in light of the protections afforded by the other technical provisions of the rule (*e.g.,* groundwater monitoring, corrective action). In the final rule, EPA is allowing unlined CCR surface impoundments to continue to operate for the remainder of the active life, provided that the facility documents through groundwater monitoring that the CCR surface impoundment is not contaminating groundwater. However, if groundwater

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monitoring at the facility demonstrates that the unlined CCR surface impoundment has exceeded any groundwater protection standard, the owner or operator must initiate corrective action, and either remove all CCR from the unit and install a composite liner (*i.e.,* "retrofit") or close within five years. In a departure from the proposed rule, CCR surface impoundments less than 40 acres may receive one two-year extension, providing for a maximum of seven years to complete closure. Units greater than 40 acres may receive up to five two-year extensions providing a maximum of 15 years to complete closure. These units are also eligible for alternative closure timeframes to account for site specific operational constraints.

In addition, under the proposed rule, CCR surface impoundments that had not closed in accordance with the rule would be subject to all the provisions of the rule. After further evaluation, EPA has revised the provision to allow an inactive CCR surface impoundment three years from publication of the rule in the **Federal Register** to complete closure. Owners or operators of inactive CCR surface impoundments that have not completed closure within this timeframe are subject to all the applicable requirements of the rule.

In response to comment and upon further evaluation the Agency is amending the location restriction relating to the placement of the CCR unit above the natural water table. Under the proposal, new landfills, any CCR surface impoundment, and all lateral expansions would have been required to have a base located a minimum of two feet above the upper limit of the natural water table. In the final rule, the Agency has amended this requirement to require that new CCR landfills and all CCR surface impoundments, and all lateral expansions be constructed with a base no less than 1.52 meters (five feet) above the uppermost aquifer or must demonstrate that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the CCR unit and the uppermost aquifer due to normal fluctuations in groundwater elevations (including the seasonal high water table.) EPA has made this change in response to comments and further evaluation demonstrating that this standard is the minimum distance necessary to demonstrate that no reasonable probability of adverse effects on human health and the environment will occur.

EPA proposed to require all new CCR landfills, CCR surface impoundments and any lateral expansion to be constructed with a composite liner. A composite liner was defined as a system consisting of two components; the upper component consisting of a minimum 30-mil FML and the lower component consisting of at least two feet of compacted soil. Based on public comments and further evaluation, the Agency is finalizing a new requirement that allows an owner or operator to install an alternative composite liner provided it meets the performance standard established in the rule. EPA has concluded that this alternative composite liner affords the same protection to groundwater resources as a composite liner.

Under the proposed rule, all CCR landfills and CCR surface impoundments would have been required to manage fugitive dusts in a manner not to exceed 35 μg/m3. The proposal also required owners or operators to control the wind dispersal of dusts consistent with the standard, and to document the measures taken to comply with the requirements. In response to comments and upon further evaluation, the Agency has removed the numerical standard of 35 μg/m3 from the rule and is establishing a performance standard for fugitive dust control. This standard requires owners or operators of any CCR unit to adopt measures that will effectively minimize CCR from becoming airborne at the facility. The Agency considers this standard to be generally consistent with the proposed rule with the added advantage of allowing for flexibility in achieving compliance. The owner or operator must also prepare an annual CCR fugitive dust control report that describes actions taken by the owner or operator to control CCR fugitive dust and to present a record of all citizen complaints during the previous year, as well as a summary of the corrective action measures taken.

## VIII. Implementation Timeframes for Minimum National Criteria and Coordination With Steam Electric ELG Rule

The final rule generally establishes timeframes for the technical criteria based on the amount of time determined to be necessary to implement the requirements (*e.g.,* installing the groundwater monitoring wells). In establishing these timeframes, EPA also accounted for other Agency rulemakings that may affect owners or operators of CCR units, namely the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG) (78 FR 34432 (June 7, 2013)) and the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Clean Power Plan) (79 FR 34830 (June 18, 2014)). Specifically, the implementation timeframes in this rule will not require owners or operators of CCR units to make decisions about those CCR units without first understanding the implications that such decisions would have for meeting the requirements of each rule. For example, this final rule requires the closure and post-closure plans to be prepared following the anticipated publication of the ELG and Clean Power Plan final rules so that owners or operators of CCR units can take into consideration those final rules as they prepare the closure and post-closure care plans.

This is also particularly true in the situation where the minimum criteria in the CCR rule could potentially require a surface impoundment to either undergo RCRA closure or retrofit with a composite liner. A decision on what action to take with that unit may ultimately be directly influenced by the requirements of the ELG rule; for example, if the final ELG rule requires a conversion to dry handing of fly ash, then it may not make economic sense for an electric utility to retrofit a surface impoundment that contains wet-handled fly ash since it would be required to cease that practice under the ELG rule. Thus, under the final timeframes in this rule, any such decision will not have to be made by the owner or operator of a CCR unit until well after the ELG rule is final and the regulatory requirements are well understood. In this example, the earliest date that a CCR surface impoundment may be triggered into a retrofit or closure decision is approximately February 2017 (the exact date would be 24 months following publication of this final rule), which would apply to a CCR surface impoundment that fails to achieve minimum safety factors for the CCR unit. This is due to the fact that the owner or operator must complete the initial safety factor assessment within 18 months of the publication of this rule plus an additional six months to initiate closure of the CCR unit if the minimum factors or safety are not achieved. The ELG rule is scheduled to be finalized in September 2015 and its effective date is 60 days following its publication. Thus, there is ample time for the owners and operators of CCR units to understand the requirements of both regulations and to make the appropriate business decisions.

The tables below summarize the implementation timeframes for the minimum criteria for existing CCR

surface impoundments and for existing CCR landfills being promulgated in this rule.

IMPLEMENTATION TIMEFRAMES FOR THE MINIMUM CRITERIA FOR EXISTING CCR SURFACE IMPOUNDMENTS

| Requirement | Implementation timeframe (number of months after publication of rule) | Description of requirement to be completed |
|---|---|---|
| Location Restrictions (§ 257.60–§ 257.64) | 42 months | —Complete demonstration for placement above the uppermost aquifer. |
| | | —Complete demonstrations for wetlands, fault areas, seismic impact zones, and unstable areas. |
| Design Criteria (§ 257.71) | 18 months | —Document whether CCR unit is either a lined or unlined CCR surface impoundment. |
| Structural Integrity (§ 257.73) | 8 months | —Install permanent marker. |
| | 18 months | —Compile a history of construction, complete initial hazard potential classification assessment, initial structural stability assessment, and initial safety factor assessment. |
| | 24 months | —Prepare emergency action plan. |
| Air Criteria (§ 257.80) | 6 months | —Prepare fugitive dust control plan. |
| Hydrologic and Hydraulic Capacity (§ 257.82) | 18 months | —Prepare initial inflow design flood control system plan. |
| Inspections (§ 257.83) | 6 months | —Initiate weekly inspections of the CCR unit. |
| | 6 months | —Initiate monthly monitoring of CCR unit instrumentation. |
| | 9 months | —Complete the initial annual inspection of the CCR unit. |
| Groundwater Monitoring and Corrective Action (§ 257.90–§ 257.98). | 30 months | —Install the groundwater monitoring system; develop the groundwater sampling and analysis program; initiate the detection monitoring program; and begin evaluating the groundwater monitoring data for statistically significant increases over background levels. |
| Closure and Post-Closure Care (§ 257.103–§ 257.104). | 18 months | —Prepare written closure and post-closure care plans. |
| Recordkeeping, Notification, and Internet Requirements (§ 257.105–§ 257.107). | 6 months | —Conduct required recordkeeping.<br>—Provide required notifications.<br>—Establish CCR website. |

IMPLEMENTATION TIMEFRAMES FOR THE MINIMUM CRITERIA FOR EXISTING CCR LANDFILLS

| Requirement | Implementation timeframe (number of months after publication of rule) | Description of requirement to be completed |
|---|---|---|
| Location Restrictions (§ 257.64) | 42 months | —Complete demonstration for unstable areas. |
| Air Criteria (§ 257.80) | 6 months | —Prepare fugitive dust control plan. |
| Run-On and Run-Off Controls (§ 257.81). | 18 months | —Prepare initial run-on and run-off control system plan. |
| Inspections (§ 257.83) | 6 months | —Initiate weekly inspections of the CCR unit. |
| | 9 months | —Complete the initial annual inspection of the CCR unit. |
| Groundwater Monitoring and Corrective Action (§ 257.90–§ 257.98). | 30 months | —Install the groundwater monitoring system; develop the groundwater sampling and analysis program; initiate the detection monitoring program; and begin evaluating the groundwater monitoring data for statistically significant increases over background levels. |
| Closure and Post-Closure Care (§ 257.103—§ 257.104). | 18 months | —Prepare written closure and post-closure care plans. |
| Recordkeeping, Notification, and Internet Requirements (§ 257.105—§ 257.107). | 6 months | —Conduct required recordkeeping.<br>—Provide required notifications.<br>—Establish CCR website. |

## IX. Implementation of the Minimum Federal Criteria and State Solid Waste Management Plans

As explained earlier in this document, the final regulations EPA is promulgating under RCRA subtitle D impose minimum federal criteria with which CCR units must comply without any additional action by a state or federal regulator. As discussed previously in this document, under the provisions of subtitle D applicable to solid waste, states are not required to adopt or implement these regulations, to develop a permit program, or submit a program covering these units to EPA for approval and there is no mechanism for EPA to officially approve or authorize a state program to operate "in lieu of" the federal regulations.

EPA has, however, received numerous comments regarding the potential implementation challenges that this statutory and resulting regulatory structure may pose, particularly in states that already have a comprehensive regulatory program governing CCR units. These concerns include the fact that facilities may need to comply with two sets of potentially differing regulations, perhaps resulting in confusion for the regulated community and the general public, and also potentially resulting in inconsistent results from citizens seeking enforcement of the criteria. The

commenters were also concerned that there is no explicit mechanism for EPA to officially approve a state program (as there is in subtitle C or in the municipal solid waste provisions of subtitle D). In addition, in states without a current formal program for overseeing CCR landfills and surface impoundments at coal fired electric utilities, stakeholders have expressed a preference for a state mechanism for implementing the federal requirements. Finally, many stakeholders expressed a strong preference for a permit program with its opportunities for public input and transparency.

Moreover, EPA recognizes the critical role that our state partners play in implementation and ensuring compliance with environmental regulations. This is particularly important in complex situations, such as presented by CCR landfills and surface impoundments that involve corrective action and requirements and timelines for closure of units. EPA expects that states will be active partners in overseeing the regulation of CCR landfills and CCR surface impoundments, and has adopted a number of provisions to ensure that States have the information necessary to undertake this role. First, the final regulations require owners or operators of regulated CCR units to notify the state of actions taken to comply with the requirements of the rule (see § 257.106). Facilities will also be required to maintain a publicly accessible internet site that will document the facility's compliance with the requirements of the rule; states (along with other members of the public) will be able to access this site to monitor facility activities (see § 257.107). (For a detailed discussion of these requirements, please see Unit VI.N of this document.)

In order to ease implementation the regulatory requirements for CCR landfills and CCR surface impoundments, EPA strongly encourages the states to adopt at least the federal minimum criteria into their regulations. EPA recognizes that some states have already adopted requirements that go beyond the minimum federal requirements; for example, some states currently impose financial assurance requirements for CCR units, and require a permit for some or all of these units. This rule will not affect these state requirements. The federal criteria promulgated today are minimum requirements and do not preclude States' from adopting more stringent requirements where they deem to be appropriate.

As noted above, commenters on the proposal voiced concerns that because EPA does not have the authority to approve a state program under subtitle D of RCRA, there is no document in which EPA formally provides its judgment that a state solid waste program substantially incorporates the minimum federal criteria. However, a mechanism for this has been available for many years through the solid waste management planning process already in the regulations at 40 CFR part 256 "Guidelines for Development and Implementation of state Solid Waste Management Plans." This process, designed early in the development of the waste management infrastructure, was structured to encourage states to effectively plan for and manage their solid wastes, including upgrading or closing any units that were considered "open dumps" through the development of SWMPs. Currently most states have SWMPs that have previously been submitted to and approved by EPA. EPA strongly recommends that states take advantage of this process by revising their SWMPs to address the issuance of the revised federal requirements in this final rule, and to submit revisions of these plans to EPA for review, using the provisions contained in 40 CFR part 256. To be clear, EPA is not suggesting that states revise their entire SWMPs, but only that states revise their plans to address the revised federal requirements being promulgated today. EPA would then review and approve the revised SWMPs provided they demonstrate that the minimum federal requirements in this final rule will be met. In this way, EPAs approval of a revised SWMP signals EPA's opinion that the state SWMP meets the minimum federal criteria.

As noted above, the part 256 regulations established the system for the development and approval of initial SWMPs as well as their revisions. For the convenience of the reader, we describe these regulations in the following paragraphs. The regulations lay out a series of requirements that a plan must meet to be approved, as well as a number of recommendations that should also be reflected in the solid waste management plan. (*e.g.*, 40 CFR 256.01–256.04 and 256.20–256.27.) For example, § 256.02 sets out the scope of the SWMPs, requiring that the plans address "all solid waste in the state that poses potential adverse effects on public health or the environment or provides an opportunity for resource conservation or resource recovery." The regulations also specify that the plan must require that all solid waste shall be disposed of in "sanitary landfills,"—*i.e.*, units that meet any federal requirements promulgated under RCRA section 4004(a)—or otherwise disposed of in an environmentally sound manner. 40 CFR 256.01(a)(2). The plan must also prohibit the establishment of new open dumps, and provide for the closing or upgrading of all existing open dumps within the state, pursuant to the requirements of RCRA section 4005. 40 CFR 256.01(a)(2)–(3). State plans must also "set forth an orderly and manageable process for achieving the objectives of the Act and meeting the requirements of these guidelines." 40 CFR 256.02(d). The regulations further specify that the plan "shall describe as specifically as possible the activities to be undertaken, including detailed schedules and milestones." Id.

The part 256 regulations further require a SWMP to identify the state's legal authorities, and regulatory powers, including any revisions that may be necessary to implement the plan. 40 CFR 256.02(e). The plan must also identify and set out the responsibilities of state, local, and regional authorities that will implement the state plan. 40 CFR 256.10(a). Thus, the SWMP is the comprehensive compendium, developed and adopted with public participation, setting forth how solid waste is managed in a particular state. As such, SWMPs have been a key component of solid waste programs for many years. As stated above, states that have approved plans will only need to address these requirements for CCR landfills and surface impoundments.

In addition to the substantive requirements, the part 256 regulations impose a number of procedural obligations. Before submission to EPA, the SWMP must be adopted by the state pursuant to state administrative processes and developed in accordance with the public participation requirements set out in § 256.60. In addition, all SWMPs were to contain procedures for revisions. 40 CFR 256.03(e). EPA anticipates that states would rely on their existing procedures to revise their SWMPs to implement the new federal criteria.

Currently, most states have approved SWMPs. These approvals were based on the requirements applicable to solid waste management that were in force at the time of approval. Now, because EPA is promulgating revised federal criteria, the facilities that will be considered to be "sanitary landfills" and "open dumps" is changing. Thus, EPA expects that SWMPs in many states will need to be revised to account for these revised Federal requirements. Consistent with the provisions in § 256.01(a)(2)–(3) and with the requirement in § 256.03(e) that such plans are to be revised where

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necessary, in order to maintain approval of these plans EPA expects that states will revise their SWMPs to account for the promulgation of revised federal criteria for CCR landfills and surface impoundments.

As fully explained later in this section, the plans are generally the best tool available for demonstrating how CCR units will be regulated in a state, including how the state intends its state requirements to relate to the federal regulations. In addition, EPA anticipates that the public participation processes will have substantial benefit, by involving all sectors of the community in addressing the management of CCR in a particular state.

EPA believes that the revised SWMPs will have significant benefits and provide the best mechanism available to respond to the concerns expressed by commenters regarding the role of states in management of this waste. First, the revised plans will enable states to set out, as part of their overall solid waste program, how the State intends to regulate CCR landfills and surface impoundments; that is, these plans can demonstrate how, if at all, the state program has incorporated the minimum national criteria and can highlight those areas where the state regulations are more stringent than or otherwise go beyond the federal minimum criteria. For example, the plan can describe the actions the state will take to oversee CCR units, particularly those units undergoing closure or corrective action, and how the State intends to review or use the notices and other information pertaining to the units that the facility owners will be providing to the state (as required in the federal regulations). Providing this detail can greatly assist the regulated community to understand the regulatory structure under which they will be operating. It can also assist the general public in understanding the regulations and thereby their ability to monitor industry's compliance with the rule.

Second, substantial benefits will be gained through the public participation process required as part of revising the state plans. See 40 CFR 256.60. At a minimum, these processes will promote greater awareness of the federal regulatory requirements, as well as how these fit into the overall context of solid waste management in the State, which will be very valuable as the new minimum criteria for CCR are implemented. In addition, these processes will provide the public and communities near CCR landfills and surface impoundments with an opportunity to participate in the decision making about how CCR are managed in their state. Finally, the record generated by the public participation process has an inherent value to states, the utilities, and the general public in that it can demonstrate explicitly the manner in which issues related to the regulation of CCR landfills and surface impoundments were raised and resolved in the state. This record would be a value in any later proceedings seeking enforcement of the rule.

Third, once EPA has approved a SWMP that incorporates or goes beyond the minimum federal requirements, EPA expects that facilities will operate in compliance with that plan and the underlying state regulations. In those circumstances, EPA's view is that facilities adhering to the requirements of a state program that is identical to or more stringent than an approved SWMP will meet or exceed the minimum federal criteria. In addition, EPA anticipates that a facility that operates in accord with an approved SWMP will be able to beneficially use that fact in a citizen suit brought to enforce the federal criteria; EPA believes a court will accord substantial weight to the fact that a facility is operating in accord with an EPA-approved SWMP. In addition, as noted above, the record generated by the public participation process in developing the SWMP has an inherent value to the states, the utilities, and the general public in any such litigation. The more specific the record is on the public process regarding how the SWMP would incorporate the minimum federal requirements and any state oversight the more valuable it would be in any court proceedings to complement EPA's approval of the SWMP. As fully explained earlier, EPA approval of a state SWMP does not mean that the state program operates "in lieu of" the federal program as EPA does not have the authority to make such a determination.

The process and criteria for approval of SWMPs are set out in 40 CFR part 256. The part 256 regulations state that EPA has six months from submittal of a plan to either approve or disapprove it. The regulations further state that EPA will approve a plan if the agency determines that the plan: (a) Meets the requirement set out in RCRA Section 4003(a)(1), (2), (3), and (5); (b) and contains provisions for revisions. Those requirements of 4003(a) are: The identification of the responsibilities of state, local, and regional authorities in the implementation of the plan and the means for coordinating regional planning and implementation; prohibition on the establishment of new open dumps and the requirement that all solid waste be utilized for resource recovery or disposed of in landfills meeting the minimum federal criteria; provision of the closing or upgrading of all existing open dumps; and no prohibition on negotiating or entering into contracts for the supply of solid waste to resource recovery facilities. In this rule, EPA has established minimum national criteria for CCR disposal facilities, which effectively define when CCR disposal facilities are open dumps. In order for EPA to approve a revised state SWMP, it must determine that the state plan provides enforceable regulatory requirements for the closing or upgrading of CCR disposal facilities that constitute open dumps. A state SWMP can do so through direct incorporation and implementation of the minimum federal criteria established by this rule or through incorporation of alternative requirements that are at least as protective of public health and the environment.

EPA anticipates that it will be able to review and approve state SWMPs that adopt the federal regulations in total or go beyond the federal minimum criteria very quickly; EPA's review of plans that do not adopt the federal minimum criteria or alter them substantially is likely to be more difficult and therefore more time consuming. EPA's review of and decision to approve or disapprove a state solid waste management plan will be based on the record before the Agency at the time of that decision. This record includes the record developed during the public participation process in which the state engaged prior to submitting the revised SWMP to EPA for approval. Should information come to EPA's attention at a later date that a state is not implementing its approved plan or taking actions at variance with the plan's provisions, EPA will take appropriate steps including potentially withdrawing approval of the SWMP.

Because SWMPs form a critical part of the implementation of this rule, EPA intends to engage the states very soon after promulgation of the minimum criteria to develop a streamlined, efficient process for review and approval of these revised plans. EPA also intends to develop both guidance for states to use to submit revisions and for EPA to use in its review of the revisions.

In addition, EPA is exploring options for developing and publishing the statutorily required inventory of open dumps. Specifically, within one year of the promulgation of federal criteria under RCRA section 4004(a), section 4005(b) directs EPA "to assist the states in complying" with the directive in section 4003(a)(3) that state SWMPs

shall provide for closure and upgrading of open dumps (*i.e.,* facilities that do not meet the revised federal criteria) by publishing an inventory of all "open dumps" in the US. 42 U.S.C. 6945(b). Because the minimum criteria promulgated today include implementation timelines, it is possible for a facility to become an open dump in the future for failure to meet the minimum criteria. Thus, EPA anticipates publishing an initial inventory and likely subsequent periodic updates.

Finally, in addition to benefits just described of a revised SWMP, RCRA Section 4005 provides an incentive in certain circumstances for states to obtain EPA approval on revised SWMPs. Under section 4005, States with approved SWMPs can provide additional time for facilities that do not meet the national minimum criteria (*i.e.,* "open dumps"), to come into compliance. As noted above, within one year of the promulgation of federal criteria under RCRA section 4004(a), section 4005(b) directs EPA "to assist the states in complying" with the directive in section 4003(a)(3) that state SWMPs shall provide for closure and upgrading of open dumps (*i.e.,* facilities that do not meet the revised Federal criteria) by publishing an inventory of all "open dumps" in the US. 42 U.S.C. 6945(b). Facilities on this inventory are eligible to obtain a "schedule of compliance" from a state with an approved management plan, provided certain additional criteria have been met. Specifically, the facility must demonstrate that it is unable to use other "public or private alternatives" to manage its waste in the non-compliant unit. In such cases, the state may establish a schedule of remedial measures that includes "an enforceable sequence of actions or operations" which must lead to compliance within a "reasonable time (not to exceed five years from the date of publication of criteria)." 42 U.S.C. 6945(a). Such a schedule would shield the facility from any suit brought to enforce the criteria. Thus, if a State receives EPA approval on its revised plan, it can offer facilities additional time, albeit limited, to come into compliance with the federal requirements. EPA expects, however, that few facilities will either be eligible for or need to take advantage of this flexibility. First, as a practical matter, only a limited number of facilities or units will fall into the category of open dumps within the relevant timeframes. As noted, an open dump is defined as a solid waste facility that does not meet the federal minimum criteria. 42 U.S.C. 6903(14). As also explained, the final criteria establish timeframes for facilities to implement the technical requirements, ranging between six months to several years, including certain provisions that authorize extensions. Until those deadlines pass, the facility is not an open dump and therefore would not be eligible for or need a compliance schedule under section 4005. Because the statute limits the states' ability to set compliance schedules to five years from the publication of the criteria, if a facility is out of compliance with the criteria either shortly before or after this time five-year timeframe, from a purely practical perspective, compliance schedules are no longer a viable option. Thus for certain of the provisions (*e.g.,* closure, which generally must be completed within five years) compliance schedules would never be available.

Second, the timeframes in the regulation reflect EPA's considered judgment of the amount of time that would realistically be needed under normal circumstances for a facility to come into compliance, based on standard engineering practices used throughout the industry. Most facilities will, in fact, be able to comply with the federal criteria within the specified timeframes, and so will not need to seek a compliance schedule. For example, as part of its Dam Safety Assessment program, EPA evaluated all CCR surface impoundments with a dam hazard potential rating of "high" or "significant," using criteria that were essentially the same as the technical criteria adopted in the final rule. As of the completion of that program, all units were either rated satisfactory, or were taking steps to ensure the structural stability of the unit. EPA acknowledges that ensuring the structural stability of these units requires continued maintenance and oversight, so past compliance is no guarantee of future compliance. However, our experience from the Assessment Program leads us to expect that the vast majority of CCR surface impoundments will be able to demonstrate compliance with the structural stability requirements in the final criteria within the specified timeframes. Any facility that seeks to justify an extension would have a heavy burden to demonstrate that anything longer than a minor amount of time is needed to implement the structural stability requirements would meet the statutory standard (*i.e.,* be "reasonable"). Similarly, absent factors beyond the facility's control (i.e, "Acts of God") EPA is unable to envision the circumstances that would support a decision that additional time beyond the 30 months already provided in the criteria to comply with the groundwater monitoring requirements would be "reasonable."

Third, RCRA section 4005(a) imposes a number of requirements that will further limit both the circumstances in which a compliance schedule may be granted, and the amount of time that states will ultimately be authorized to grant. 42 U.S.C. 6945(a). Section 4005(a) requires that to obtain a compliance schedule, the facility must first demonstrate that it has considered other public or private alternatives to comply with the prohibition on open dumping and is unable to utilize such alternatives.[127] At a minimum, this means that the facility must demonstrate that there are no alternative units that meet the federal requirement, either on-site or off-site, that can be used to dispose of the CCR. EPA also interprets this provision to require the facility to demonstrate that it has made a good faith effort to comply with the criteria, which would include documenting the actions that had been taken, along with the facts demonstrating the reasons that compliance was not feasible within the criteria's timeframes. As has been previously discussed, cost is not a factor that is appropriately considered under sections 1008(a)(3), 4004(a), or 4005(a), and so would not provide an adequate justification for these purposes either.

Further, the statute requires that a schedule for compliance specify "a schedule of remedial measures, and an enforceable sequence of actions, leading to compliance within a reasonable time." Id. This means that any compliance schedule must lay out precisely the activities that remain to be completed, along with clear and enforceable deadlines for each. Again, this will effectively serve to limit the ultimate amount of time that would be granted in any individual case.

Finally, as stated earlier, the statute requires that any schedule to bring an open dump into compliance is to be limited to a "reasonable time," that is not to exceed five years from the date of publication of the federal criteria. Whether a particular period of time is "reasonable" depends on the facts of the particular situation, but, generally speaking, it should take into account the technical complexity of the requirement, the activities that remain

[127] Upon promulgation of criteria under sections 1008(a)(3) and 4004(a), the continued use of any unit that does not comply with these criteria is prohibited, as "open dumping," unless a compliance schedule has been established.

to be completed, the reasons for the lack of compliance, and other particular factors such as geology, geography, weather, and engineering circumstances. For example, EPA expects that a significantly lower amount of time would be reasonable for a facility that simply chose to delay implementation than for a facility whose compliance was complicated by factors beyond its control. Overall, to be consistent with the statute, EPA expects that facilities seeking to establish an alternative compliance schedule would need to provide a factual justification that not only documents the reasons that compliance within the criteria's timeframes was not feasible, but carefully documents the facts that would support a determination that any significant extension of time to come into compliance is "reasonable."

EPA expects that as part of any revised solid waste management plans, a state would explain the criteria it intended to use to determine whether and how much additional time to comply with the federal criteria should be granted. See 40 CFR 256.04(f) and 256.26. Consistent with the statute's directives, EPA expects that any extension would be limited to the time absolutely necessary to bring a unit into compliance, and that five years would not automatically be granted. Nor would a revised solid waste management plan that granted all "open dumps" an additional five years generally meet the regulatory criteria for approval. Id. EPA also expects that states would consider the original timeframes laid out in the criteria. As previously discussed, in developing these time frames EPA sought to achieve a balance between the minimum amount of time that would realistically be needed to properly and adequately implement the technical requirements, and the need to expeditiously address the significant risks associated with CCR units. EPA therefore expects that in granting additional time under compliance schedules, states will be guided by the same considerations. As documented throughout this preamble, CCR disposal units do pose significant risks to public health and the environment; it is therefore critical that actions to implement these criteria be taken expeditiously to address these risks. EPA intends to closely review those portions of a state solid waste management plan that address the processes and criteria for establishing compliance schedules.

In conclusion, EPA believes that the use of the solid waste management plan revision process is the best mechanism available under RCRA subtitle D to address the states' interest in obtaining formal EPA "approval" of their solid waste management plans. EPA will continue to work with the states as the rules are implemented to ensure that this process is streamlined and efficient.

## X. Risk Assessment

EPA revised and updated the 2010 draft risk assessment using mathematical models to determine the rate at which chemical constituents may be released from different waste management units (WMUs), to predict the fate and transport of these constituents through the environment, and to estimate the resulting risks to human and ecological receptors. Modeling was conducted in a step-wise fashion, with more refined analyses used at each subsequent step. Below, EPA discusses how the risk assessment was revised and updated in response to the various public comments received. The Agency also provides a summary of the analyses conducted as part of the risk assessment and the final conclusions drawn from these analyses. For further discussion, see the revised risk assessment and response to comments documents available in the docket.

### *A. Response to Public Comments*

EPA received numerous, general comments on both the draft risk assessment and subsequent NODAs. These comments tended to express general support or disapproval for the risk assessment methodology, data, or results. However, these comments did not provide any specific technical recommendations or data that could be used to improve the risk assessment. EPA appreciates the overwhelming interest of the public regarding the Agency's risk assessment. However, without any substantive critique that could be acted upon, EPA could not alter the risk assessment in response to these more general comments. To the extent that any commenter mentioned substantive issues regarding a specific aspect of the risk assessment, these comments are further addressed in subsequent sections of this preamble.

#### 1. Comments Related to Fate and Transport Modeling

COMMENT: Commenters wondered how realistic results may be using a risk assessment model that assumes current conditions will be maintained for 10,000 years. Specifically, commenters were concerned about the assumption that constituent concentrations in the leachate remain constant throughout that timeframe. In addition, commenters questioned the assumption that well use and climate conditions will remain constant for 10,000 years.

EPA RESPONSE: EPA acknowledges that the 10,000-year groundwater modeling time horizon required further clarification in the revised risk assessment. Thus, the text in the revised risk assessment has been updated to make it clear that the selection of a *maximum* 10,000-year time horizon does not mean that all model simulations continue for the full 10,000 years. Specifically, Section 4 states:

*EPA ran the model until either the observed groundwater concentration of a constituent at the receptor point reached a peak and then fell below a model-specified minimum concentration ($10^{-16}$ mg/L), or the model had been run for a time period of 10,000 years.*

Although groundwater concentrations are modeled beyond the observed peak or maximum average concentrations, these post-peak or post-maximum average predictions are not used in estimates of risk. In many cases the leachate plume reaches the receptor point much sooner than 10,000 years. As discussed in Section 5 and appendix K of the revised risk assessment, on a national scale, both unlined and clay-lined surface impoundments consistently pose peak risks within 100 years. Meanwhile, composite liners show much longer peak arrival times, close to 10,000 years for most surface impoundment runs. Peak arrival times are longer for landfills, and more than 10,000 years for composite-lined landfills. Under such timeframes, EPA acknowledges that surface conditions may change significantly, compounding the uncertainty associated with the predicted exposures and risks. However, EPA also notes that the time to first exceedance of selected risk criteria is typically considerably less than the time to the greatest exceedance.

EPA acknowledges that future groundwater use patterns may shift as the number and location of receptors changes, and that it is unknown whether future changes in receptor locations and other surface conditions would result in greater, lesser, or the same risk as predicted in this analysis. However, no known data exist that would allow EPA to do more than speculate about future population dynamics. Thus, the Agency relied on the best available data on the current population to conduct the revised risk assessment. The approach used to place residential groundwater wells is further discussed in Section 4 and appendix B of the revised risk assessment, and the associated uncertainties are discussed in Section 5.

COMMENT: Comments related to the specifics of the groundwater transport modeling were received from commenters. Issues covered in their comments included the following:

Geochemical Modeling:

- The way that soil and aquifer $K_d$ values were determined and used, including the fact that the risk assessment did not explicitly model oxidation/reduction reactions and precipitation-dissolution processes that may influence the chemical fate and transport.
- Whether hydrogeologic settings were assigned correctly.

Selection of Sorbents:

- The selection of iron oxides, and dissolved organic matter (DOM) and particulate organic matter (POM) to represent all sorbents in soil and aquifer materials.
- The selection of goethite as the iron oxide mineral used to estimate sorption to vadose zone and aquifer materials.
- The treatment of POM and DOM in the MINTEQA2 modeling used to generate the $K_d$ values (sorption isotherms) used in the analysis.
- The adequacy of sensitivity and uncertainty analyses for the MINTEQA2 modeling.

$K_d$ Values:

- The approach used to determine the value of pH in the aquifer for selecting $K_d$.
- The subsequent calculation of the retardation factor.

Arsenic Speciation:

- The assumption that arsenic III is the only or dominant form of arsenic is too conservative, as arsenic III readily converts to the less mobile arsenic V species under aerobic conditions.
- A commenter requested time to exceedance results for arsenic species and other constituents, as well as distance versus concentration output from EPACMTP.

EPACMTP Assumptions and Simplifications:

—The appropriateness of EPACMTP and its various assumptions and simplifications for groundwater modeling, including:
—Not altering the chemistry of the aquifer receiving leachate.
—Not simulating variable oxidation-reduction potential conditions or multiple chemical species during a model run.
—Not evaluating the potential mobilization of non-waste related metals from soils when exposed to leachate with potentially different geochemistry compared to ambient conditions.
—Not considering the potential occupation of adsorption sites by naturally occurring metals or competition from multiple contaminants.
—Not considering mounding-induced reduction of the unsaturated zone thickness or other cases where the groundwater table is in direct contact with the bottom of the WMU.
—Not considering fractured rock, karst, and other complex hydrogeologic settings.

The comments also addressed the general need for more transparency in the data and methods used in the analysis and the need for validation and/or comparison of model inputs and results to site-specific field data.

EPA RESPONSE: The following is EPA's response broken out by subtopic.

Geochemical Modeling:

EPA recognizes that explicit reactive/geochemical modeling would be more realistic than using linear and nonlinear partitioning coefficients. EPA considered the use of the Objects Representing Chemical Speciation and Transport (ORCHESTRA) model during revisions to the risk assessment because it can account for geochemical interactions, such as aqueous complexation, precipitation, surface complexation, and ion exchange.[128] However, such modeling is not a practical approach for a nationwide analysis because the data collection effort necessary to populate such a model on a nationwide, location-based level would be prohibitively expensive. Even assuming such data were available to populate ORCHESTRA or a similar model, the complexity of the algorithms necessary to account for highly variable geochemical and hydrogeologic conditions nationwide and the time required to run such a model would also be impractical. Furthermore, the use of $K_d$ as a surrogate for dilution/sorption/precipitation processes is a widely used and accepted method in both the scientific literature and the groundwater modeling community, provided the values of $K_d$ used are appropriate to account for the range of potential attenuation processes.[129] Therefore, for a nationwide analysis, the use of $K_d$ is a practical and necessary simplification. EPA has added discussion to the risk assessment to clarify $K_d$-related issues raised by the commenters. Appendix H of the revised risk assessment displays select percentiles of the $K_d$ values used in the analysis. These values were derived from the isotherm sampling performed by EPACMTP and used in the modeling (including effective $K_d$ values for the unsaturated zone). A listing of all individual $K_d$ values available in the MINTEQA2 isotherms used in these analyses would not be practicable. Instead, the full input and output files are available to the public in the docket.

Some commenters suggested that EPA should focus on the effect of redox potential in the groundwater on fate and transport. While this is possible, it would take significant effort to set up this type of approach for every inorganic constituent considered in the risk assessment, and it was determined not to be necessary. EPA did indirectly account for some of the major effects of redox potential when modeling arsenic and other constituents for which speciation is known to have a significant impact on mobility. For these constituents, a model run was conducted for each species under the assumption that all of the constituent mass was present as that speciation. Therefore, EPA did not evaluate redox, and acknowledges this is a source of uncertainty for the groundwater transport modeling approach. Commenters expressed concern about the assumption of a single speciation, noting that it is likely that constituents will be present as some combination of the different species. EPA acknowledges that this approach is a simplification of real world conditions; however, the Agency believes this approach is useful because it provide bounding estimates that can inform the risk assessment.

Regarding the concern that there were possible errors in hydrogeological assignments, these assignments have been updated in the revised risk assessment based on a more robust and accurate dataset for waste management units (WMU) and facility locations. These data are discussed in Section 3 and appendix B of the revised risk assessment. Because these assignments were based on more complete GIS coverages of soils and aquifers across the U.S., they are more consistent and reliable than the previous ones in representing the spatial variability in hydrogeologic environments needed by the EPACMTP model.

Selection of Sorbents:

In recent years, databases of equilibrium sorption reactions have been compiled in the literature for several of the dominant potential sorbents in the environment, including two common iron oxide minerals: hydrous ferrous oxides (HFO) and

[128] Meeussen, J.C.L. 2003. ORCHESTRA: An Object-Oriented Framework for Implementing Chemical Equilibrium Models. *Environmental Science & Technology* 37(6):1175–1182.

[129] U.S. EPA. 1999. *Understanding Variation In Partition Coefficient, Kd, Values Volume I: The Kd Model, Methods of Measurement, and Application of Chemical Reaction Codes.* EPA 402–R–99–004A. OAR. Washington, DC. August.

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goethite.[130] [131] Because of the availability of these data and their prevalence in the environment, these are the sorbent types available for MINTEQ2 modeling used to develop constituent sorption isotherms. Other common hydrous oxides that can sorb chemicals include hydrous oxides of aluminum, manganese, and silicon (Dzombak and Morel, 1990); however, there were insufficient data on these to consider their use. To determine the most appropriate iron oxide sorbent, EPA chose goethite as the most appropriate form of hydrous iron oxide for the risk assessment to avoid an underestimation of risk. While both goethite and HFO are common forms of iron oxide in soils, goethite is a much poorer adsorbent than HFO, thereby leading to relatively greater groundwater plume concentrations. EPA acknowledges that HFOs are common as well and there is the potential for HFOs with greater sorption affinities than goethite to be present at some CCR disposal sites. In reaching this conclusion, EPA consulted experts who published on this subject (specifically, Dr. David Dzombak, Dr. Samir Mathur and Dr. Jerry Allison), developer of MINTEQA2. EPA agrees that this was a necessary assumption.

EPA also recognizes that limiting MINTEQA2 to two types of sorptive materials (iron oxide and organic matter [DOM and POM]) is a simplification given the wide range or soil and aquifer materials that actually adsorb metals (*e.g.,* clay and other soil minerals). However, given that the extensive sorption databases needed to perform MINTEQA2 are available for POM, DOM, and goethite, they are the best representation of subsurface sorption processes active in soils and aquifer materials. This decision and the actual approaches used to model DOM, POM, and goethite are described in detail in MINTEQA2 background documents and the associated Response to Peer Review Comments for those documents.

Finally, with respect to the adequacy of sensitivity and uncertainty analyses for MINTEQA2, EPA notes that the 2009 sensitivity analysis showed that only results for strongly sorbing constituents were sensitive to the $K_d$ values output from MINTEQA2. In contrast, the three risk drivers identified in the revised risk assessment (arsenic, lithium, and molybdenum) all tend to be weakly sorbing, with the exception of arsenic in the pentavalent state. Furthermore, to the extent $K_d$ affects the risks, Section 5 of the revised risk assessment evaluated these effects by examining alternate speciation (*e.g.,* trivalent and pentavalent arsenic) as well as the effect of waste type and waste pH. For these reasons, EPA finds that sufficient sensitivity and uncertainty analyses were conducted.

$K_d$ Values:

The approach adopted in the risk assessment to determine the value of pH in the aquifer (used to select $K_d$) and the subsequent calculation of the retardation factor assumed that, after entering the aquifer, the leachate plume would thoroughly mix with the ambient, uncontaminated groundwater. One commenter stated that the mixing zone would only be present at the periphery of the groundwater plume. This is consistent with the general conceptual model used in this risk assessment of uniform subsurface flow with recharge. However, EPACMTP requires a constant groundwater pH in each model run to model transport with nonlinear sorption isotherms. EPA assumed full mixing as a more conservative approach to selecting pH because, for most metals, sorption/precipitation tends to increase (*i.e.,* $K_d$ goes up) with higher pH, which is characteristic of much CCR leachate (*i.e.,* assuming full mixing lowers the groundwater pH and, thus, decreases sorption). To characterize the potential effect of this simplifying assumption on calculated risk results, EPA conducted an uncertainty analysis that is presented in Section 5 of the revised risk assessment.

EPA considered comparing the modeled $K_d$ values to available estimates in the published literature, but did not do so for three reasons. First, there are many individual values within each $K_d$ isotherm that depend both on constituent concentrations and MINTEQA2 master variables, such as pH, organic carbon, and iron oxide concentrations. Second, measured values are limited to specific sites where conditions that may not be fully documented, and because such variables can vary from site to site, it can be very difficult to determine exactly how well the collected values represent conditions across the country. Third, field and laboratory methods for measuring $K_d$ vary greatly and are not easy to compare, adding a significant measurement uncertainty to the variability issues mentioned above. Therefore, not only would this comparison be complicated to perform, it would also be subject to its own numerous uncertainties and unknown biases, making it unlikely to provide a basis for definitive conclusions about the representativeness of the current approach.

With respect to comments on the calculation of the retardation factor, EPA points commenters to U.S. EPA (2003) [132] which discusses how EPA uses $K_d$ values to model sorption in the subsurface environment.

Arsenic Speciation:

Commenters also pointed out that literature on arsenic V often shows that it is orders of magnitude less soluble than arsenic III, which appears inconsistent with the results of the 2010 Draft Risk Assessment. The draft assessment found similar exposure concentrations for both arsenic species. As a result of a combination of different updates to the revised risk assessment, the modeled concentrations of arsenic III and V are now generally an order of magnitude different, although the specific results vary between pathways. One cause of this difference is likely the increased distances to receptors in the revised risk assessment. The increased distance would lead to additional arsenic V attenuation because this species sorbs more readily (*i.e.,* has greater $K_d$ values) than arsenic III. Section 5 of the revised risk assessment discusses the uncertainty associated with modeling both species of arsenic. For the specific concentrations at various distances, EPA directs the commenter to review the input and output files available in the docket.

EPA did not model the time to first exceedance of risk criteria, but did conduct a sensitivity analysis for the time to peak groundwater concentration. The time to peak results for arsenic species and other select constituents are presented in Section 5 of the revised risk assessment. The distance to nearest well receptors is also discussed in Section 5 of the revised risk assessment. The relation of distance versus concentration was not explicitly evaluated on a per simulation basis, rather all receptor well locations within one mile from the WMU footprint were included in the analysis to provide a conservative risk estimate.

EPACMTP Assumptions and Simplifications:

Comments on the treatment of dispersivity within EPACMTP highlighted the need for greater transparency about the model's

[130] Dzombak, D.A and F.M.M. Morel. 1990. Wiley-Interscience, New York, 393 pp.

[131] Mathur, Samir S. 1995. *Development of a Database for Ion Sorption on Goethite using Surface Complexation Modeling.* Carnegie Mellon University, M.S. Thesis, Department of Civil and Environmental Engineering.

[132] U.S. EPA (Environmental Protection Agency). 2003. *EPA's Composite Model for Leachate Migration with Transformation Products (EPACMTP).* Technical Background Document. EPA 53–R–03–002. Office of Solid Waste, Washington, DC.

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underlying assumptions and input data sources. The documentation for the 2010 Draft Risk Assessment did not include comprehensive tables detailing model input parameters, their values or distributional characteristics, and the sources of the data used. These values are, in many cases, publicly available in the EPACMTP Background and Parameters/Data Background documents.[133] [134] EPA still finds it inappropriate to duplicate this large amount of data. Instead, the revised risk assessment includes an increase in the number of references to these documents, and directs readers to refer to these documents for further information. Additionally, the full input and output files are available to the public in the docket.

With respect to the fundamental questions raised about the assumptions and simplifications built into EPACMTP, EPA acknowledges some limitations within the model. Some simplifications are necessary to complete a large, national scale risk assessment, and the model provides the most appropriate available tool to complete this type of analysis. As discussed in Section 5 of the revised risk assessment, EPACMTP has been thoroughly peer reviewed and tested for application in large-scale risk assessments. This section also provides additional documentation on these internal and external reviews of the model, its limitations, and the associated uncertainties. With respect to particular criticisms levied:

- EPA alters the chemistry of the aquifer receiving leachate by changing the aquifer pH in response to full mixing. Alternatively, EPA conducts an analysis in Section 5 using the alternate assumption of partial mixing;
- EPA evaluates alternative species in separate model runs. As described in the revised risk assessment, EPA believes that presentation of these two results bound the range of possible risks from a constituent. To the extent that EPA does not model oxidation-reduction potential, EPA notes that this would require geochemical modeling, which was not feasible for the reasons discussed above;
- Full mixing of the leachate plume did not demonstrate significant potential to affect aquifer pH. Thus, since pH is one of the most significant factors affecting constituent mobilization EPA does not believe significant constituent mass from the underlying soils will be mobilized in most cases. Instead, it is a site-specific consideration that is not possible to include in a nationwide risk assessment.
- A discussion of sorbent competition as a limitation of the analysis is discussed in Attachment H–1 of appendix H in the revised risk assessment.
- EPA did not consider groundwater mounding, groundwater in contact with the waste management unit, fractured rock, karst, and other complex hydrogeologic settings as these are site-specific considerations that could not be accommodated in a nationwide risk assessment.

COMMENT: Several commenters discuss the use of site-specific analysis to increase confidence in the risk assessment results. They expressed concern that the results are difficult to evaluate given the significant variability and uncertainty associated with the national scope of the analysis, and that validation or calibration of EPACMTP results with actual data is needed, including the potential use of damage cases.

EPA RESPONSE: Commenters expressed concern about validation of the EPACMTP model with actual field data and some commenters suggested that EPA should use actual monitoring data rather than modeling to assess potential risks. EPA recognizes the importance of monitoring data in characterizing specific sites. EPA agrees with the commenters that confidence in the results of an environmental fate and transport model increase significantly when model predictions can be compared favorably with measured field results. However, site-specific modeling involves extensive data collection and detailed modeling (representing site-specific conditions and processes), which was not possible for this large, national-scale risk assessment. Available site-specific data are limited to a relatively small fraction of locations and settings. This risk assessment was intended to represent a broad range of potential conditions. Consequently, EPA validated the model results with actual field data by comparing the results of the national probabilistic, Monte Carlo analysis to proven/potential damage cases from across the United States. These damage cases represent real-world instances of contamination from CCR WMUs that provide the best available comparison for the results of the risk assessment. This comparison is presented in Section 5 of the revised risk assessment. EPA also provided extensive EPACMTP validation results relative to theoretical models and field data in appendix D of the EPACMTP technical background document (U.S. EPA, 2003a,b).[135]

COMMENT: Comments relating to the number of wells contaminated, the realistic risk of exposure, well placement within the plume, distance to receptor wells, identification of surface water receptors, surface water interception modeling, the appropriateness of receiving water reaches (*e.g.* the nearest surface water body), and other receptor or well-related issues were received from public commenters.

Surface Water Interception Modeling:

Regarding surface water interception, many comments were supportive of EPA's approach for simulating the interception of groundwater by surface water bodies, which has been added to the revised risk assessment. However, some commenters indicated that a meaningful allocation of the groundwater plume between a surface water body and a downgradient well receptor can only be determined reliably with assessment of the system at a local scale.

Commenters also raised questions regarding the specific surface water interception methodology, including the base data and algorithms used to calculate stream base flow, net groundwater flow, and the contaminant mass loss to groundwater. Concern was expressed about the large range of possible values used for Monte Carlo sampling without calibrating models to site specific conditions and the potential to mismatch parameters. Additionally, concerns were raised that the assessment assumed transport directly to the nearest water body without reflecting complexities that are often present and could lead to longer transport pathways or to pathways to water bodies other than the nearest.

Commenters noted that the vicinity of many WMUs is serviced by a municipal water supply, and; therefore, there would be no drinking water receptors associated with these WMUs. Comments were also received that the one mile distance considered by the transport model is not sufficient, because actual receptor wells in many cases are further than one mile from facilities. Comments also highlighted the possibility that modeled receptor well concentrations may incorrectly represent actual

[133] U.S. EPA. 2003. *EPA's Composite Model for Leachate Migration with Transformation Products (EPACMTP): Parameters/Data Background Document.* EPA 530–R–03–003. Office of Solid Waste, Washington, DC. April.

[134] U.S. EPA. 2003. *EPACMTP Technical Background Document.* Office of Solid Waste, Washington, DC.

[135] U.S. EPA (Environmental Protection Agency). 2003a. *EPA's Composite Model for Leachate Migration with Transformation Products (EPACMTP).* Technical Background Document. EPA 53–R–03–002. Office of Solid Waste, Washington, DC.

exposures by sampling from a single aquifer depth. Comments on dispersivity noted the need for greater transparency in the report.

Placement of Receptor Wells, EPACMTP Well Inputs and Assumptions:

Comments related to the risk assessment's use of water well distances from MSWLFs and the Agency's belief that these distances would be protective for CCR WMUs. Additional comments focused on the assumption that the wells used in this assessment are contaminated (*i.e.,* located within the plume), even if the well location used reflects a deeper well that may be screened in an uncontaminated aquifer; the manner in which the assessment handles uncontaminated wells, plume characteristics, groundwater-surface water interactions, vertical contaminant concentration across a screened interval in an aquifer; and the values used for plume dispersivity.

EPA RESPONSE: The following is EPA's response broken out by subtopic.

Surface Water Interception Modeling:

In cases where receptor wells are located downgradient from a surface water body that intersects the groundwater table, some or all of the groundwater, along with the mass of constituents contained therein, is intercepted by the water body before it can reach the well. This interception was not modelled in the 2010 Draft Risk Assessment. However, a review of the input database for the 2010 Draft Risk Assessment found that such a water body was present in approximately two-thirds of the Monte Carlo runs. Furthermore, ignoring the loss of constituent mass had the effect of overestimating exposures. Thus, in the revised risk assessment an EPACMTP model post-processor was created to account for surface water interception by removing constituent mass flowing into the water body from the groundwater plume, and leaving only the remaining groundwater available to migrate to a drinking water receptor. The approach used to account for interception is discussed in further detail in Section 4 and appendix J of the revised risk assessment.

While commenters were generally supportive of the proposed approach, some indicated that a meaningful allocation of constituent mass from groundwater into a surface water body required site-specific data. Concerns were raised about the assumption that transport occurred directly to the nearest water body without reflecting complexities that are often present and could lead to longer transport pathways or to pathways to water bodies other than the nearest. EPA acknowledges that local conditions can make groundwater flow conditions complex, and detailed, local-scale assessments would be required to describe these conditions accurately. While EPA agrees that local-scale conditions must be considered for precise estimation for specific systems, it was impractical for EPA to characterize, simulate, and calibrate models for the numerous locations across the nation. Discussion of the uncertainties associated with this approach has been added to Section 5 of the revised risk assessment.

Several questions about the surface water interception methodology were raised by the public. The qBaseflow input parameter was derived from the NHDplus mean recharge parameter (MEAN_RCHRG) [136] and the size of the water body catchment and reach (see appendix B of the revised risk assessment). The approach assumes that all streams intersect the shallow aquifer and that all streams either gain water from the aquifer or do not interact with the aquifer at all (for simplicity and conservatism). As the commenter indicates, qNetflow is a key result calculated by subtracting the stream baseflow from the average groundwater flow upgradient of the stream. The qNetflow value becomes the adjusted groundwater flow beyond the stream, reflecting groundwater losses to the stream. One commenter raised a specific question about how the methodology handles cases where qNetflow is less than zero, but greater than the average groundwater flow. This case does not occur with the methodology adopted by EPA, because qNetflow is always equal to or less than the average groundwater flow (*i.e.* streams are assumed not to be losing). If qNetflow is negative (*i.e.,* a losing stream), all of the groundwater is assumed to migrate to any wells on the opposite side of the stream.

Model Validation/Calibration:

Concern was expressed about the large range of possible values used in the probabilistic analysis for certain parameters and the potential for this to result in a mismatch of input parameters without proper site-specific calibration. EPA notes that the revised risk assessment is not intended to capture the exact risks at each disposal site. Instead, the revised assessment combines the best resolution of site-based, regional and national data available to provide an estimate of potential risks that may occur from current disposal practices. While the assigned data for any given model iteration may not reflect the exact conditions at a real-world site, the resulting sum of all model iterations reflect the range of potential conditions near each WMU, weighted by prevalence, across the conterminous United States.

Placement of Receptor Wells, EPACMTP Well Inputs and Assumptions:

Comments regarding placement of receptor wells in the probabilistic analysis (also known as the appropriateness of receiving water reaches) are the result of a fundamental misinterpretation regarding the constraints placed on groundwater receptor location to be, as described in the 2010 Draft Risk Assessment, "within the contaminant plume." This constraint is more fully explained in Section 4.4.3.6 of the EPACMTP technical background document.[137] A citation referring readers to that document has been placed in Section 4 of the revised risk assessment. Because the comment resulted from a misunderstanding, EPA does not believe the sensitivity analysis suggested by the commenter is necessary.

Some commenters were concerned that many residents in the vicinity of some WMUs may be serviced by a municipal water supply. Because these residents would not be exposed to groundwater, the risk assessment could overestimate exposures. EPA acknowledges that there may be a large percentage of the population that does not rely on groundwater as a source of potable water; however, the aim of the risk assessment is to estimate the magnitude of potential risk to the exposed population. Thus, this does not represent a significant source of uncertainty in the risk assessment.

Comments were also received that the one-mile distance considered by the transport model is not sufficient, because actual receptor wells in many cases are further distant than one mile from facilities. EPA conducted a sensitivity analysis, discussed in Section 5 of the revised risk assessment, which indicates that risks beyond the one-mile distance are appreciably lower than risks within one mile. Given that the highly exposed population was adequately captured by a one-mile radius, the significant additional effort required to extend the analysis further downgradient was unjustified.

[136] Available online at: *water.usgs.gov/GIS/metadata/usgswrd/XML/nhd_recharge.xml.*

[137] U.S. EPA (Environmental Protection Agency). 2003a. *EPA's Composite Model for Leachate Migration with Transformation Products (EPACMTP).* Technical Background Document. EPA 53–R–03–002. Office of Solid Waste, Washington, DC.

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With respect to comments related to the placement of wells within deeper aquifers, EPA has a policy of addressing uncertainty by erring in favor of the protection of human health and environmental quality. Consistent with this practice, wells screened within vulnerable, surficial aquifers (*i.e.,* the top 10 meters of the saturated zone) continue to be the primary focus of the Agency's national-scale modeling efforts. Comments also highlighted the possibility that modeled receptor well concentrations may incorrectly represent actual exposures by sampling from a single aquifer depth. Wells are typically screened across an extended depth, and may capture both contaminated and pristine groundwater. Due to the constraints of EPACMTP, EPA maintained the current approach of modeling exposures at a single depth. A discussion of the uncertainties associated with this approach has been added to Section 5 of the revised risk assessment.

In response to comments on the use of MSW landfill data to predict the distance to private wells, EPA did not use the MSW data in the revised risk assessment. Instead, EPA used synthetic population representations of U.S. Census data to place each household and its occupants at discrete points across the landscape surrounding CCR WMUs. Synthetic populations are realistic representations of households and individual residents and their attributes in a given census area, and are based on methods that identify realistic locations within each block by using LandScan 90-meter night-time population distributions to place each household across the landscape.[138] From these households, a distribution of the distances to the nearest well was created. This approach is discussed in more detail in appendix B of the revised risk assessment. Some commenters suggested that EPA develop site-specific estimates of actual populations around facilities rather than relying on synthetic populations to determine potential receptor locations. The synthetic approach provides the maximum spatial resolution possible for publically available population data from the U.S. Census. More site-specific estimates would be costly, but not necessarily more accurate.

Some commenters were also concerned that the assessment did not consider direct discharges from surface impoundments to surface water. This pathway was outside the scope of the assessment, because it is regulated by the NPDES program. However, this pathway was evaluated in *Environmental Assessment for the Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category,*[139] which will be revised in support of final effluent limitation guidelines due to be released in September of 2015.

2. Comments Related to Source Modeling

COMMENT: The majority of the public commentary in this subcategory was dominated by the assertion that Toxicity Characteristic Leaching Procedure (TCLP), Synthetic Precipitation Leaching Procedure (SPLP) and other laboratory leachate test data are not applicable to CCR wastes. Comments specifically regarding the use of Leaching Environmental Assessment Framework (LEAF) data for modeling leaching behavior noted that the data should be applied appropriately and pointed out the following: (1) That the range of conditions (*i.e.,* range of pH) encompassed by the LEAF data is broader than those conditions found in the field for CCR disposal; (2) high pH limits the mobility of leaching constituents; (3) the need for validating LEAF leachate concentrations against field data if available; and (4) the reliability of the LEAF data is questionable as a result of inconsistencies identified in the LeachXS Lite™ database.

EPA RESPONSE: Only pore water and impoundment water data were used to characterize surface impoundments. Therefore, the comments received on the use of laboratory leachate data are not relevant for the surface impoundment scenario. For landfills, EPA agrees that TCLP, SPLP and other single pH test methods may not be the most appropriate leachate extraction methods for all waste streams and all disposal scenarios. The 2010 Draft Risk Assessment relied on a hierarchy of dissolved concentration data to characterize leaching from landfills, ranging in order of preference from field leachate data to TCLP. However, new data collected using the LEAF test methods have been made available through a series of EPA reports.[140] [141] [142] LEAF were collected with three LEAF methods, specifically:

- SW–846 Method 1313 (and its predecessor, Method SR02);
- SW–846 Method 1314; and
- SW–846 Method 1316 (and its predecessor, Method SR03).[143]

With the availability of the LEAF data, EPA no longer relied on other data sources to model landfills because the inability to identify trends in leaching behavior from single pH tests made it impossible to link these data together with the LEAF data in the probabilistic analysis. The LEAF data provide information on the leaching behavior of CCR for a range of pH values observed in CCR landfills, as well as the liquid-to-solid ratio of the pore water. The data from these three methods were used in conjunction to characterize landfill leaching. While the natural pH range for any individual sample may be narrower than the full range analyzed with the LEAF methods, many facilities burn a range of coal types under varying operating conditions, and co-dispose with other materials, so the range of pH for a specific CCR sample may be exposed to is wider than the pH estimated based on one sample alone.

EPA agrees that appropriate use of the data is needed to ensure that data represent likely conditions of leaching occurring at range of facilities nationwide taking into account local specific environmental conditions, the geometry of monofill, type of coal, air pollution control, and other factors that affect leaching. Since the NODAs were released, a report comparing leachate from field and laboratory analyses has been completed.[144] The report includes the use of geochemical speciation modeling as needed to reflect site-

[138] Bhaduri, B., E. Bright, P. Coleman, and M. Urban. 2007. LandScan USA: A high resolution geospatial and temporal modeling approach for population distribution and dynamics. *GeoJournal 69*:103–117.

[139] U.S. EPA. 2013. Environmental Assessment for the Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category. EPA–821–R–13–003. Office of Water. Washington, DC. 20460. April.

[140] U.S. EPA. 2006. *Characterization of Mercury-Enriched Coal Combustion Residues from Electric Utilities Using Enhanced Sorbents for Mercury Control. EPA–600/R–06/008.* Prepared by F. Sanchez, R. Keeney, D. Kosson, and R. DeLapp for the U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division. February.

[141] U.S. EPA. 2008. *Characterization of Coal Combustion Residues from Electric Utilities Using Wet Scrubbers for Multi-Pollutant Control. EPA/600/R–08/077.* Prepared by F. Sanchez, D. Kosson, R. Keeney, R. DeLapp, L. Turner, and P. Kariher for the U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division. July.

[142] U.S. EPA. 2009. *Characterization of Coal Combustion Residues from Electric Utilities—Leaching and Characterization Data.* EPA–600/R–09/151. Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC. December.

[143] Methods SR02 and SR03 are predecessor methods to SW–846 Methods 1313 and 1316.

[144] U.S. EPA. 2014. *Leaching Test Relationships, Laboratory-to-Field Comparisons and Recommendations for Leaching Evaluation using the Leaching Environmental Assessment Framework (LEAF).* EPA–600/R–14/061. EPA Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC 27711. November.

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specific factors affecting leaching, and shows that LEAF methods provide realistic predictions of environmental releases across the range of pH.

All three LEAF methods are summarized in appendix C, with the leachate data provided in Attachment C–5 of the revised risk assessment. Additionally, the inter-laboratory validation for these methods are described in U.S. EPA (2012a, b) [145] [146] while Kosson et al. (2002) [147] provides the detailed test methodology for the predecessor methods, SR02 and SR03. The noted discrepancies and classification errors within LeachXS Lite have been corrected.

COMMENT: Public comments focused on the general relevance of the facility data based on age and noted that newer data should be used to more accurately reflect the current state of CCR management. Related comments cited that the grouping of waste and liner types by facility is not representative of current conditions. Another commenter suggested that the outcomes for different liner types were not comparable and should not be used to make relative conclusions about liner performance. It was also suggested that the assumed three-foot clay layer underlying composite liners is too thick, and two feet would be more representative of current practice. Commenters also described existing management controls required in some geographical locations that mitigate potential risks (*e.g.,* liners, leachate collection) and requested that EPA reflect the existence of those controls in their analysis, as well as mismanagement scenarios when these controls are not in place.

EPA RESPONSE: Since the purpose of the risk assessment was to evaluate risks for the universe of currently operating facilities and WMUs, EPA generally agrees with the commenter that the 1995 EPRI and 2006 DOE survey data relied on in the 2010 Draft Risk Assessment may be outdated. Thus, EPA collected data from several new sources of information on the facilities, WMUs, and liners that are present at the time of this analysis. Further discussion of these data sources is available in Section 2 and appendix A of the revised risk assessment.

Regarding the inclusion of mismanagement scenarios, EPA reviewed the high-end pore water concentrations and determined that these data represent actual CCR samples and therefore represent possible high-end risks from current management practices. To better understand which practices may lead to the highest risks, EPA conducted sensitivity analyses that consider the influence of liner type, liner design, waste type and other variables on model results. The results of these analyses are presented in Section 5 of the revised risk assessment.

Several commenters described existing management controls required in some geographical locations that mitigate potential risks (*e.g.,* liners, leachate collection) and requested that EPA reflect the existence of those controls in the final risk analysis. The Agency's analysis reflects the presence of different management scenarios at WMUs to the extent the available data allowed (*e.g.,* WMUs were assumed to have liners if the information indicated such). A key objective of the analysis was to compare the effectiveness of management options (*e.g.,* liners; surface impoundments versus landfills) at preventing potential releases and exposures. Because the population of WMUs considered in the analysis included a range of management controls, the analysis does provide such comparative results between management options. The uncertainties associated with the updated facility, WMU and liner data are discussed in Section 5 of the revised risk assessment.

COMMENT: One commenter suggested that the risk assessment applied risk results for fly ash to bottom ash, FGD sludge, and other CCR wastes, which may result in an incorrect estimate of risks for these other wastes. Other commenters called for EPA to evaluate each CCR waste independently. A public commenter expressed concern about whether the risk assessment adequately considered alternative CCR disposal scenarios. Specifically, it was noted that CCR codisposed with coal refuse generate more acidic conditions (*i.e.,* lower pH) due to higher-levels of sulfide minerals, which may significantly impact the mobility of metals.

EPA RESPONSE: In the revised risk assessment, EPA modeled a combined ash waste types for the majority of surface impoundments and all landfills. Although commenters are correct that different CCR wastes may behave differently when monofilled, the 2009/2010 EPA survey data indicates that the CCR are codiposed in a majority of units. Thus, EPA believes this approach appropriately reflects current disposal practices.

With regard to the evaluation of CCR codisposed with coal refuse, EPA notes that the pore water data used to characterize surface impoundments were broken out separately for this waste type evaluation. These data reflect samples collected in the field and are representative of the pH at which these samples are managed. While some ash and coal refuse samples are highly acidic, others are more neutral or slightly basic (full pH range of 1.7 to 8.2). The development and application of these waste types is discussed in Section 3, Section 4 and appendix H of the revised risk assessment, while the associated uncertainties are discussed in Section 5. For landfills, waste pH, which is the major driver of variations in $K_d$ values used to distinguish waste types, was known with great accuracy for CCR nationwide because U.S. EPA (2009a) [148] compiled a full, nationwide distribution of CCR pH. In this distribution, disposal of ash with coal refuse is reflected is the acidic tail of the distribution. For the national probabilistic analysis, EPA aggregated model runs for ash and coal refuse (surface impoundments) and acidic waste (landfills) with other wastes so that risks reflected the prevalence of these disposal practices. However, EPA also performed sensitivity analyses to understand the extent that the lower pH of co-managed wastes could affect risks, which is discussed in Section 5 of the revised risk assessment.

COMMENT: Commenters stated that it is unclear why EPA chose to approximate infiltration through composite liner systems based on leak detection system flow rates from industrial landfills that use a different construction design than projected for CCR landfills.

EPA RESPONSE: The composite liner leakage rates used for this risk assessment correspond to leakage rates developed for the peer-reviewed Industrial Waste Management

[145] U.S. EPA. 2012. *Interlaboratory Validation of the Leaching Environmental Assessment Framework (LEAF) Method 1314 and Method 1315.* EPA/600/R–12/624. Prepared by A.C. Garrabrants, D.S. Kosson, R. DeLapp, P. Kariher, P.F.A.B. Seignette, H.A. van der Sloot, L. Stefanski, and M. Baldwin for the U.S. EPA Office of Research and Development, Air Pollution Control Division. September.

[146] U.S. EPA. 2012b. *Interlaboratory Validation of the Leaching Environmental Assessment Framework (LEAF) Method 1313 and Method 1316. EPA/600/R–12/623.* Prepared by A.C. Garrabrants, D.S. Kosson, L. Sefanski, R. DeLapp, P.F.A.B. Seignette, H.A. van der Sloot, P. Kariher, and M. Baldwin for the U.S. EPA Office of Research and Development, Air Pollution Control Division. September.

[147] Kosson, D.S., H.A. van der Sloot, F. Sanchez and A.C. Garrabrants. 2002. An integrated framework for evaluating leaching in waste management and utilization of secondary materials. *Environmental Engineering Science 19*(3):159–204.

[148] U.S. EPA. 2009. *Characterization of Coal Combustion Residues from Electric Utilities—Leaching and Characterization Data.* EPA–600/R–09/151. Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC. December.

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Evaluation Model (IWEM).[149] The types of synthetic liners used are likely to be the same, regardless of the type of waste present. EPA is unaware of any factors specific to CCR that would exacerbate leakage rates, nor did the commenter provide any. Thus, in the absence of any information to the contrary, EPA finds these to be the best available data.

Because there is currently no approach for differentiating between flow from unimpacted water released by the consolidation of clay and from contaminated leakage through the liner, EPA excluded data on the subset of composite liners constructed with natural clay from the distribution of composite liner leakage rates. EPA did consider the potential impact of incorporating these additional data into the risk assessment as part of sensitivity analysis, presented in Section 5 of the revised risk assessment.

COMMENT: Concerning the treatment of non-detect values in the risk assessment, one commenter recognized that the use of one half the detection limit in calculations has become an accepted protocol. However, it was suggested that this approach may not be appropriate in all cases, and that newer or more straightforward methods can be applied to improve precision and minimize biasing of the dataset. Another commenter noted that mercury was excluded from the analysis due to the high number of non-detects.

EPA RESPONSE: Additional constituent data measured with lower detection limits have been made available to EPA since completion of the 2010 Draft Risk Assessment. However, the overall CCR constituent database still contains a large number of non-detect data for some constituents. EPA continues to incorporate all available with the use half the reported detection limit as the most appropriate method to account for these non-detects. The commenter is correct that much of the pre-2010 mercury data has high detection limits and a large proportion of non-detects. In this one instance, EPA relied only on the newer data made available to the Agency since the 2010 Risk Assessment, which was collected through newer methods with significantly lower detection limits. A more detailed rationale for this approach is provided in Section 3 of the revised risk assessment, along with further discussion of the uncertainty in Section 5.

[149] U.S. EPA. 2002. *Industrial Waste Management Evaluation Model (IWEM) Technical Background Document.* EPA530–R–02–012. Office of Solid Waste, Washington, DC. August.

COMMENT: Comments received related to the effect of waste compaction in landfills focused on changes to hydrologic properties of waste materials, such as porosity and hydraulic conductivity. These changes may result from compaction, consolidation, hydration or geochemical changes, and have the potential to result in either an underestimation or overestimation of risks.

EPA RESPONSE: EPA acknowledges that the landfill source model does not consider the compaction of CCR waste that may occur over time as a result of anthropogenic activities, gravity or infiltrating water. However, no data on either the rate or degree to which these processes may occur were provided by commenters or identified elsewhere. EPA considered the impacts of this uncertainty in Section 5 of the revised risk assessment.

COMMENT: Public comments focused on assumptions relating to the variability of unlined landfill design, landfill clay liner materials, and construction of landfill cover materials and construction. Specific comments emphasized that the clay liner and cover thickness assumptions (three feet) were too conservative and not conservative enough, respectively. Commenters also questioned why composite covers and leachate collection systems were not considered for clay-lined landfills. Additionally, commenters stated that there was a high degree of variability in the material and design and construction for unlined landfills that was not accounted for in the HELP modeling. One commenter also pointed out that the assessment may overestimate percolation rates from landfills by underestimating the use of engineering controls. In addition, a commenter stated that the assessment assumes that States will require liners in all cases which may not be the case, thereby weakening the regulation.

EPA RESPONSE: For both unlined and clay-lined landfills, EPA used Hydrologic Evaluation of Landfill Performance (HELP) model-derived infiltration rates. These infiltration rates assume that the cap placed on top of the landfill at the end of its useful life will remain intact for the duration of the risk assessment, up to a maximum 10,000 years of modeling. A commenter pointed out that hydraulic conductivity of a clay liner is likely to increase by orders of magnitude due to desiccation resulting from natural temperature cycles. Additionally, commenters stated that there was a high degree of variability in the material and design and construction for unlined landfills that was not accounted for in the HELP modeling. EPA has adopted the use of the HELP model, which was subject to both peer and administrative review, as the source of unlined and clay-lined infiltration rates for landfill for nearly two decades. EPA acknowledges that there are limitations in using HELP. However, the model has been tested and verified as discussed in the EPACMTP Parameter/Data Background Document.[150] To the extent that the performance of the cap will decrease over time, EPA acknowledges that unlined and clay-lined infiltration rates calculated by HELP may be underestimated, however the degree of that underestimate is unknown. Discussion of this uncertainty has been added to Section 5 of the revised risk assessment.

COMMENT: One commenter expressed concern over the fact that the assessment modeled all disposal sites above the water table. The commenter indicated that many surface impoundments and landfills are deep and can come in direct contact with the water table. This will result in an underestimation of peak concentrations, arrival times and risks for these WMUs. Furthermore, the commenter emphasized that the use of the unsaturated zone flow module to calculate infiltration from the bottom of impoundments underestimates true risks in the consolidated sediment, and noted that clogged soil layers should be treated as saturated rather than unsaturated.

EPA RESPONSE: EPA acknowledges that EPACMTP is not designed to handle scenarios where the water table is above the bottom of the landfill. However, EPACMTP can accommodate surface impoundments in direct contact with the water table. If unit geometry and the selected depth to the water table create a scenario where the bottom of the unit is in contact with the water table, then the entire soil column is considered saturated. Otherwise, even for very high infiltration rates, regions beneath impoundments will remain partially saturated when there is sufficient distance between the unit and the water table. EPA has added a discussion of the uncertainties associated with WMU source terms and EPACMTP in Section 5 of the revised risk assessment.

EPA believes the commenter misunderstood how the sediments were modeled for surface impoundments. The EPACMTP unsaturated zone

[150] U.S. EPA. 2003. *EPA's Composite Model for Leachate Migration with Transformation Products (EPACMTP): Parameters/Data Background Document.* EPA 530–R–03–003. Office of Solid Waste, Washington, DC. April.

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module assumes that the 0.2 m of consolidated sediments at the bottom of a surface impoundment are always saturated whereas the 0.5 m of clogged native soil are assumed to be unsaturated when the bottom of the surface impoundment is above the water table.

COMMENT: Public commenters recommended that EPA address the future increase in mercury and $NO_X$ compounds levels in CCR that will result from mercury capture from flue gas under new emission control regulations. Commentary pointed out that the recent Vanderbilt study should provide data that could be used to expand the risk assessment in this area.

EPA RESPONSE: The risk assessment was designed to evaluate the risks associated with current management practices and, as such, draws no conclusions about the potential for future air pollution technologies to alter the composition or leaching behavior of CCR wastes. However, it has been shown that newer mercury pollution control technologies currently in place have the potential to affect leaching behavior.[151] [152] [153] Thus, EPA conducted a sensitivity analysis to evaluate the risks associated with existing units that dispose of this waste; however, the data were too few to allow EPA to draw conclusions about the effect of pollution control technologies on the risks. This sensitivity analysis is presented in Section 5 of the revised risk assessment.

COMMENT: Multiple public commenters noted that additional pore water will improve the risk assessment, but TCLP and SPLP data are not appropriate for use as source concentrations. Additionally, commenters stated that EPA applies the LEAF data to pH conditions that are not realistic to CCR disposal scenarios. Although LEAF provides a more representative and scientifically sound approach, it must be correctly adapted. Alternative statistical methods to represent the input data as a range is certainly feasible and could enhance the risk assessment if the range of data is used as an input to the risk assessment.

Commenters agree that the LEAF data does provide useful information, but point out that it is associated with the potential for leaching and does not represent actual leaching of a specific CCR under actual field conditions. Commenters argues that field leaching data should not be mixed with laboratory data, and that EPA's field leachate dataset (for landfills and impoundments) is not adequate for use in the CCR risk assessment. Specific efforts recommended to properly utilize the LEAF data include: Use of probability density functions for leachate concentrations based on pH and/or L/S ratios in the Monte Carlo process; selection of leachate concentrations based on pH and L/S and tied to the geographic location of the WMU and CCR type; and geochemical modeling to incorporate reactions once leachate impacts groundwater.

A few commenters pointed out that the pore water data are generally representative, although concerns were raised about the highest arsenic concentration (81 mg/L) in the dataset. One commenter believed that although the addition of new data is an improvement, EPA could greatly improve the accuracy of the model's results by removing the extreme and unsubstantiated outlier data driving its high risk cases. Another commenter believed the assumption that concentration of contaminants in the sediment pores (applicable to a post closure scenario) would be equal to the concentration assigned to in the impoundment water would result in underestimated risks. Additionally, commenters noted that EPA should classify the data according to CCR type and coal type.

Overall, commenters support updates to the pore water data and the use of statistical method to normalize the data curve. However, one commenter noted that EPA should not use commenter-submitted CCR pore water data unless it meets requisite applicable data quality requirements. Another commenter stated that EPA needs to provide better clarity on these solicited comments (on the use of older pore water data) and provide these documents in the docket. Without these documents, the reader does not have a complete understanding of co-managed material containing CCR. Another comment noted that properly collected field pore water (freely draining) samples should take priority over any of the laboratory generated data and freely draining pore water is more representative of leachate releases than tightly held pore water.

EPA RESPONSE: The use of pore water data is still considered the most appropriate approach to estimate constituent fluxes to groundwater for CCR surface impoundments. This is because pore water better represents the leachate seeping from the bottom of the impoundment than impoundment water samples. EPA did not use available LEAF data for surface impoundments because a national distribution of pH was not available to allow the Agency to probabilistically assign LEAF concentrations to these units, and because there was no way to account for partitioning of the leachate into wastewater versus porewater. Thus, EPA has continued to rely on pore water data, supplemented with data from the 2010 comments. EPA appreciates commenter support on the use of pore water data and statistical methods for data analysis for surface impoundments. EPA agrees that data available for minefill sites may not be representative of disposal in surface impoundments. Thus, these data were not considered in the revised risk assessment. The specific handling of pore water concentration data with site quartiles, rather than site averages, is discussed in Section 4 and Section 5 of the revised risk assessment report.

EPA agrees that TCLP and SPLP data are less appropriate for CCR disposal scenarios and no longer uses these data in the revised risk assessment. EPA adapted the LEAF methods and data for landfills, as this is the best available approach and data to represent CCR landfill leachates, and does not mix or use field data with LEAF laboratory results for landfill leachate. The LEAF data are considered the most robust and technically defensible data available. As noted in the 2010 Environmental Science and Technology publication,[154] the data represents the largest collection of comprehensive characteristic leaching data to date.

A commenter noted that the LEAF data provide the potential for leaching and not actual leaching of a specific CCR under actual field conditions. The commenter suggests using probability distribution of key factors affecting leaching behavior [*i.e.*, pH and liquid/solid ratio (L/S)] and site specific data tied to the geographic location of the management unit and the type of CCR being managed. In the revised risk assessment, pH is expressed as a

[151] U.S. EPA. 2006. *Characterization of Mercury-Enriched Coal Combustion Residues from Electric Utilities Using Enhanced Sorbents for Mercury Control. EPA–600/R–06/008.* Prepared by F. Sanchez, R. Keeney, D. Kosson, and R. DeLapp for the U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division. February.

[152] U.S. EPA. 2008. *Characterization of Coal Combustion Residues from Electric Utilities Using Wet Scrubbers for Multi-Pollutant Control. EPA/600/R–08/077.* Prepared by F. Sanchez, D. Kosson, R. Keeney, R. DeLapp, L. Turner, and P. Kariher for the U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division. July.

[153] U.S. EPA. 2009. *Characterization of Coal Combustion Residues from Electric Utilities—Leaching and Characterization Data.* EPA–600/R–09/151. Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC. December.

[154] Thorneloe, S., D. Kosson, F. Sanchez, A. Garrabrants, and G. Helms. 2010. Evaluating the Fate of Metals in Air Pollution Control Residues from Coal-Fired Power Plants. *Environ. Sci. Technol. 44:*7351–7356.

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national distribution for selecting leachate concentrations developed to represent CCR nationally, and L/S is considered in estimating washout leachate concentrations based on field data observations. The use of the pH distribution developed in U.S. EPA (2009) [155] does capture the range of potential variability in pH conditions at CCR sites nationwide and is the best approach possible given the current availability of information on site-specific coal ash chemistry. Although leachate concentrations were selected considering pH and L/S conditions that are nationally representative, EPA does not have the detailed and extensive site-specific measurements that would be needed to tie CCR and leachate concentrations to specific WMU locations. Instead, EPA adopted a national probabilistic approach that is site-based and representative of risks to human and ecological health across the country. The revised risk assessment also provides details regarding how the LEAF data are used in combination of geographical specific data such as hydrology, precipitation, fill configuration, CCR type, pH, L/S ratio, and other factors that take the leaching potential as an input to fate and transport models accounting for attenuation and dilution. Additionally, an effort was made to collect CCR samples that characterize the range and quantity of coal usage in the U.S. along with likely air pollution control configurations. While the data is not statistically representative on a site-specific basis, it is adequate to identify trends in leaching behavior that relate to differences in materials types, APC technology, and coal rank. Geochemical speciation modeling was not conducted because the source term as measured and interpreted is conservative, provided that oxidizing conditions occur.

Regarding the number and concentration of pore water samples, EPA reviewed the high-end pore water concentrations and determined that these represent actual CCR samples that therefore represent possible high-end risks if CCR is inadequately regulated and managed. EPA recognizes that more pore water data would potentially improve the representativeness of the dataset, but is convinced that the current dataset adequately captures the possible high end risks that are of most interest in the rulemaking, including risks from the mismanagement of CCR through codisposal with coal refuse.

The assumption that saturated contaminant concentrations in surface impoundment sediments are at equilibrium with the impoundment waters is a conservative assumption that is unlikely to significantly underestimate risks. This assumption is further discussed in Section 5 of the revised risk assessment report.

Regarding commenter-submitted pore water data, EPA conducted a review of the additional datasets provided by the commenters with respect to relevance and data quality. Based on the available information, EPA determined that the selected datasets were relevant and acceptable in terms of data quality requirements. However, EPA does not have sufficient data to distinguish between freely draining and tightly bound pore water data at this time. Overall, EPA agrees that the use of these data introduces some uncertainty into the analysis, which is discussed in Section 5 of the revised risk assessment.

COMMENT: One commenter questioned the assumption that there will be no net addition of waste into a surface impoundment during and after the operational life, noting that impoundments are frequently deepened. Additionally, many surface impoundment wastes are left in place at the time of closure, so that the waste behaves more as a landfill than a surface impoundment (and increasingly, with new landfills being constructed on top of previous surface impoundments). Another commenter questioned why the conceptual model assumes that impoundments are always full during their operating life, which overestimates releases to the subsurface. Additionally, a commenter noted that the assumption of only 0.2 m of sediment accumulation underestimates the amount of sedimentation and subsequently overestimates the amount of percolation to the subsurface. The commenter stated that in actual operation, ash thickness can increase up to 30 feet or more, eventually filling the impoundment, which results in a significant decrease in percolation through the base. Furthermore, the commenter questioned the assumption that post-closure percolation continues at the same rate as during active operations.

EPA RESPONSE: Based on the 2009/2010 EPA surveys, it was assumed that the majority of the surface impoundments are storage impoundments, which are continuously dredged. Because these facilities have other units (whether onsite or offsite) established for disposition, it likely that the majority of waste in the dredged impoundments would be removed by the end of the unit's operating life. Regardless, an uncertainty analysis provided in appendix K demonstrates that the risks during the operating life of surface impoundments are greater because the higher hydraulic head drives leachate into underlying soils with greater force than gravity alone post-closure. Therefore, EPA did not explicitly model the post-closure phase of surface impoundments. The uncertainties resulting from this decision are discussed in Section 5 of the revised risk assessment.

EPA acknowledges that EPACMTP is restricted to modeling flow as steady state with the assumption that an impoundment always has a fixed depth of wastewater. EPA further acknowledges that such an assumption may overestimate infiltration. The surface impoundment conceptual model assumes that sediments are periodically dredged and removed and that the long-term average thickness of the sediment is approximately 0.4 m, with half of that layer consolidated. EPA has used EPACMTP and its predecessor model versions for a longstanding time period and it has undergone multiple rounds of internal and external review. The reviews associated with EPACMTP and its limitations are further discussed in Section 5 of the revised risk assessment report.

COMMENT: Public commenters suggested that risks from operating landfills should be considered along with those that occur post-closure. These commenters questioned whether greater risks may occur during site operations when wastes are uncovered and exposed directly to precipitation. Additional commenters noted that complete leaching of all constituent mass at a constant concentration is overly conservative.

EPA RESPONSE: The landfill source model used in this risk assessment is not able to address landfills during operation because the non-linear sorption isotherms used require a constant, annualized infiltration rate throughout the duration of leaching. Instead, the revised risk assessment assumed that the full footprint of the landfill is filled to capacity with a cap no less permeable than the soil or liner underlying the WMU is present at the start of leaching. EPA acknowledges that this approach introduces some uncertainty into the analysis, the potential impacts of which are discussed in Section 5 of the revised risk assessment.

With respect to comments that complete leaching of all constituent mass is overly conservative, EPA now

[155] U.S. EPA. 2009. *Characterization of Coal Combustion Residues from Electric Utilities—Leaching and Characterization Data.* EPA–600/R–09/151. Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC. December.

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models landfills using leachable mass as discussed in Section 4 and appendix C of the revised risk assessment. Alternatively, EPA presents a sensitivity analysis of these results compared with the results generated using total mass in Section 5.

3. Comments Related to Exposure Scenarios

COMMENT: The commenter emphasized that the risk assessment does not consider direct discharges to ground and surface water systems other than groundwater infiltration (*e.g.,* direct injection to groundwater, point and nonpoint discharges to surface water systems). It was recommended that EPA consider combining contributions from these sources with CCR groundwater leaching impacts to calculate the full load of CCR constituents to groundwater and surface water systems. The commenter continues by suggesting that the use of liners in impoundments does not reduce overall hazards if direct discharges are considered in the risk assessment.

EPA RESPONSE: RCRA waste disposal risk assessments do not address direct discharges from impoundments to surface waters because they are regulated as permitted point source discharges under the Clean Water Act by EPA's Office of Water. Since this pathway is outside the scope of the risk assessment, the revised risk assessment does not consider these releases. However, this pathway was evaluated in the Environmental Assessment for the Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category,[156] which will be revised in support of final effluent limitation guidelines (ELG) due to be released in September of 2015. The revised risk assessment was updated to note this fact.

EPA is not aware of any CCR disposal where waste is directly injected into groundwater aquifers, and absent any data on this practice declines to evaluate it.

COMMENT: Public comments were received on the methodology applied to evaluate exposure to fugitive dust during landfill operations (before closure). The majority of these comments focused on the fugitive analysis as presented in *Inhalation of Fugitive Dust: A Screening Assessment of the Risks Posed by Coal Combustion Waste Landfills,*[157] and EPA's proposed approach for refining the analysis. Comments received on the initial fugitive dust analysis methodology and modeling ranged from emphasizing that the approach was overly conservative in some cases to underestimating risk in other cases.

Multiple comments were provided on the proposed methodology for refining the fugitive dust analysis that was applied in the revised risk assessment. One commenter recommended that 2010/2011 EPA survey data should be used to refine the fugitive dust analysis for landfills. Specifically, the current OW data indicate that active portions of the landfills are significantly smaller than the landfills identified in the 1995 EPRI survey. Several comments were received that pointed out that the application of AERSCREEN and AERMOD is appropriate if representative or realistic inputs are used including meteorological data, material silt content, source areas for subcells of ash management units and consideration of common operating and control practices, which are in some cases defined by the states (*e.g.,* Virginia). However, one commenter expressed concern that no previous or current EPA regulatory model; including SCREEN3, AERSCREEN or AERMOD; has been rigorously tested and evaluated for performance in modeling fugitive emissions associated with CCR landfills.

In general, the commenters supported or recommended the use of appropriate AP–42 factors and other techniques to estimate emissions. Others noted that consideration of deposition impacts and constituent-specific modeling is appropriate. One commenter recommended that EPA should conduct a full-scale assessment that considers fugitive dust as well as emissions from landfills and emissions of diesel particulate matter from haul trucks, on-site heavy-duty landfill equipment, and diesel-powered pumps and generators, with potential receptors of interest as residents and sensitive subpopulations living near the power plant, along the transportation route and at the landfill. Another commenter expressed concern over the lack of metal speciation data, while another comment concerned gas emissions from the landfills (*e.g.,* hydrogen sulfide). One final commenter voiced concern that insufficient information was provided on the modeling approach and the model inputs to support evaluation and allow comments on the overall validity or propriety of the suggested modeling.

EPA RESPONSE: The majority of the comments received concerning exposures during landfill operation (before closure) focused on the assessment of fugitive dust. EPA acknowledges that the 2010 Draft Risk Assessment did not evaluate the inhalation pathway, relying instead on the findings of a previous evaluation, *Inhalation of Fugitive Dust: A Screening Assessment of the Risks Posed by Coal Combustion Waste Landfills.*[158] This previous evaluation only considered releases from windblown emissions and the potential to exceed national ambient air quality standards (NAAQS) for particulate matter.

Based on the comments received, EPA updated the screening analysis of fugitive dust. EPA agrees that there are potential risks posed by fugitive emissions from sources beyond wind and revised the analysis to consider emissions from a range of activities, such as vehicular activity, unloading operations and spreading/compacting operations. Emissions from these sources were calculated using techniques that have undergone extensive peer-review, including *AP–42: Compilation of Air Pollutant Emission Factors.*[159] Screening level modeling was performed with a combination of AERSCREEN and AERMOD to estimate dust dispersion and deposition rates. Model inputs were selected to be representative of current landfills, environmental settings (*e.g.,* meteorological conditions) and common dust management practices. Estimated air concentrations were used to screen acute and chronic health risks from inhalation, as well as the potential to exceed NAAQS standards. Furthermore, EPA considered exposures that may result from the offsite deposition on and accumulation in downgradient media. This was done for all relevant metal species. In contrast, EPA did not evaluate emissions of hydrogen sulfide to air as EPA has no data on the extent to which this constituent is present in CCR or released into the surrounding environment. Further discussion of this screening analysis is presented in

[156] U.S. EPA. 2013. Environmental Assessment for the Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category. EPA–821–R–13–003. Office of Water. Washington, DC 20460. April.

[157] U.S. EPA. 2010. *Inhalation of Fugitive Dust: A Screening Assessment of the Risks Posed by Coal Combustion Waste Landfills.* OSWER. Washington, DC. September.

[158] U.S. EPA. 2010. *Inhalation of Fugitive Dust: A Screening Assessment of the Risks Posed by Coal Combustion Waste Landfills.* OSWER. Washington, DC. September.

[159] U.S. EPA. 1985. *Compilation of Air Pollutant Emission Factors. Volume I: Stationary Point and Area Sources (Fourth Edition).* AP–42. U.S. Environmental Protection Agency, Office of Air and Radiation and Office of Air Quality Planning and Standards, Research Triangle Park, NC. September.

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Section 3 and appendix F of the revised risk assessment.

COMMENT: Comments both supported and disagreed with the appropriateness of a screening analysis to eliminate pathways from consideration in the full-scale probabilistic analysis. One commenter pointed out that the EPA conducted a very conservative, but appropriate, screen to identify constituents to include in the full-scale probabilistic analysis. Another commenter emphasized that a full-scale risk assessment should be conducted that assesses exposures concurrently through all pathways (*e.g.,* including surface pathways with inhalation exposure) for all chemical constituents. In particular, they emphasized that inhalation exposures to human carcinogens, such as hexavalent chromium, as well as noncarcinogens may occur through the aboveground pathway. Although the commenters disagreed over the use of a screening approach, both expressed concerns over the use of risk attenuation factors to scale screening risks to the full-scale risks for the subset of constituents that did not pass the screen and were not evaluated under the full scale assessment. Both commenters believe that this approach ignores the unique fate and transport properties of the omitted constituents and that the use of a simplistic, attenuation factor is not an appropriate way to estimate risk.

EPA RESPONSE: By first conducting the screening analysis presented in Section 3 of the revised risk assessment, EPA was able to focus available resources on the characterization of risks for exposure routes and constituents with the greatest potential to pose risks. The screening analysis conducted for the revised risk assessment considered all of the potential exposure routes identified in the conceptual models for surface impoundments and landfills, which included aboveground exposures to ambient air, soil, sediment, produce, and animal products. Each exposure pathway was evaluated for all constituents (and individual species, as appropriate) for which both concentration and toxicity data were available.

The screening analysis was developed to be protective of highly exposed individuals. Due to the conservative nature of the screening, the calculated risks represent a protective, but unlikely, combination of conditions that most likely reflect an upper bound on potential exposures for each individual constituent. The revised screening assessment did not rely on risk attenuation factors to screen out constituents. All constituents that resulted in screening-level risks above human health or ecological criteria, and for which characterization of fate and transport could be refined, were carried forward for further consideration in the probabilistic analysis, described in Section 4 of the revised risk assessment. It is possible that consideration of exposure to multiple constituents through a single pathway or to the same constituent through multiple pathways may have resulted in the retention of some additional constituents. However, it is highly unlikely that these additional constituents would remain risk drivers once more realistic dilution and attenuation in the environment is considered.

COMMENT: Multiple commenters noted that there may be additional constituents present in CCR wastes beyond those quantitatively evaluated in the risk assessment. In particular, multiple commenters referenced organics and radionuclides. Some commenters called on EPA to quantify the risks associated with these additional constituents. Others claimed that these constituents are present in low levels and do not pose risk to receptors.

EPA RESPONSE: In the *Report to Congress: Wastes from the Combustion of Fossil Fuels: Volume 2—Methods, Findings, and Recommendations,*[160] EPA reviewed the available data on organic constituents, such as polyaromatic hydrocarbons and dioxins. These data indicated that concentrations of all organics are near or below analytical detection limits both in CCR and in the leachate released from CCR. Based on the findings of this report, the Agency concluded that organic constituents were not risk drivers and did not require further evaluation. In the absence of additional data that demonstrate the organic composition of CCR wastes have markedly changed, EPA continues to rely on these findings.

EPA acknowledges that, like other inorganic constituents, naturally-occurring radionuclides may be concentrated in CCR waste through the combustion of coal. However, due to a lack of data that could be used to characterize leachate concentrations for individual radionuclides, a quantitative evaluation of risk was not conducted. To address this data gap, EPA has included radionuclides in the list of constituents for groundwater monitoring. Furthermore, potential transport of these constituents downgradient by windblown dust and storm run-off are addressed through requirements for fugitive dust controls and run-on/run-off controls.

4. Comments Related to Human Exposure and Toxicity

COMMENT: Some commenters argued that EPA underestimated risks by not considering combined chemical effects, additive risk and concurrent exposures through multiple pathways. One commenter indicated that EPA should conduct a full scale assessment that considers concurrent exposure from ingestion of fish and groundwater. Commenters also raised concerns that some chemical constituents share a common mechanism of toxicity and may affect the same body organ or system, resulting in greater risks than predicted through the consideration of each constituent separately.

One commenter noted that the combination of risks from different constituents would not change the overall results of the risk assessment. Constituents concentrations found to result in an HQ less than 1 in the screening analysis are unlikely to make a meaningful contribution to overall risk regardless of whether multiple compounds share the same toxicological endpoints. Additionally, the commenter expressed that it would be inappropriate to add the risks from different constituents as modeled because the constituents do not all arrive at a hypothetical receptor at the same time, due to differing mobility in the subsurface environment.

EPA RESPONSE: EPA acknowledges that this risk assessment considered potential risks to human health from individual constituents and individual pathways. EPA acknowledges that not explicitly evaluating cumulative risk is a source of uncertainty that may result in some underestimation of risks. It is possible that an individual could be exposed to risks from drinking contaminated groundwater, as well as eating contaminated fish from a local surface water body, but it is unlikely that these two exposure pathways would occur simultaneously with any appreciable frequency in the real world. It is even more unlikely that a receptor would be exposed to both media at the high-end concentrations modeled. Therefore, the magnitude of the uncertainty introduced into the risk assessment is likely to be small. It is also possible for an individual to be exposed to multiple constituents through a single pathway. This is a more likely scenario because, as demonstrated

[160] U.S. EPA (Environmental Protection Agency). 1999b. Report to Congress: Wastes from the Combustion of Fossil Fuels: Volume 2—Methods, Findings, and Recommendations (EPA 530–R–99–010). Office of Solid Waste and Emergency Response. Washington, DC.

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by the available data, CCR typically leach multiple inorganic constituents. Where exposure to multiple constituents is likely to occur, EPA policy is to assume that the risks resulting from these exposures are additive.[161] The current probabilistic analysis identified individual constituents above risk criteria. Many of the other constituents modeled resulted in risks an order of magnitude or more below risk criteria. Thus, the consideration of additive risk, even with the high-end risks modeled in this risk assessment, is unlikely alter the principal results of the probabilistic analysis. Similarly, because the risks for individual constituents were found to be above levels of concern, consideration of additive risk is unlikely to meaningfully change the results of the analysis. EPA updated the revised risk assessment to include a discussion of the associated uncertainties in Section 5.

COMMENT: Some commenters identified incorrect and inconsistent reporting of toxicity benchmark values and recommended conducting a thorough review of literature to ensure the use of the most current values were used. One commenter expressed concern over the use of the current IRIS value for arsenic carcinogenic effects and believes it underestimates risk. Other commenters emphasized that it would be inappropriate for EPA to consider using the draft oral cancer slope factor (CSF) for arsenic and the oral CSF for hexavalent chromium [chromium (VI)] published by the New Jersey Department of Environmental Protection (NJDEP). Concerning lead, one commenter supported a peer reviewer's recommendation to use the Integrated Exposure Uptake Biokinetic (IEUBK) model to calculate human health risks, especially for young children. Additionally, a commenter requested chemical-specific information on toxicity criteria derivation, as well as information on the relationship between environmental exposures to specific chemicals and adverse health effects. The commenter emphasized that this information would provide an uncertainty discussion regarding toxicity values, facilitate communication with the public, and provide a balanced perspective on risk.

EPA RESPONSE: Human health benchmarks were chosen based on the Office of Solid Waste and Emergency Response hierarchy (OSWER Directive 9285.7–53).[162] EPA reviewed the benchmarks to confirm their accuracy and determine whether newer values have become available from EPA or other sources used by EPA since the CCR draft risk assessment was conducted. The current, updated list of human health benchmarks is provided in appendix E of the revised risk assessment, and the references cited in that appendix provide further information on the potential adverse effects and derivation of toxicity criteria.

For lead, EPA used the drinking water maximum contaminant level (MCL) to estimate risks from drinking water exposure in the draft risk assessment. In the revised risk assessment EPA continued to rely on the MCL, but also used IEUBK model for lead in children as described in Section 5 of the revised risk assessment. While lead failed the screening assessment, risks from lead exposure in the probabilistic assessment were well below the risk criterion, and did not drive risks in either the probabilistic or any sensitivity analyses.

COMMENT: The commenters questioned why the cancer benchmark of $1 \times 10^{-5}$ was selected while the typical range used by OSWER and EPA guidance is a range from $1 \times 10^{-4}$ to $1 \times 10^{-6}$. The commenters suggested that an explanation is necessary. In particular, one commenter requests clarification on the phrase "point of departure" when supporting the use of the cancer benchmark of $1 \times 10^{-5}$. Concerning non-cancer criteria, a commenter suggested that non-cancer risks should be report as follows: Worst Case—Assume maximum exposure scenarios including exposure 24-hours/day, 365 days/year for 70 years; High End—95th percentile based on national human activity pattern distributions; Central Tendency—50th percentile (or median) risk based on national human activity pattern distributions. Furthermore, another commenter believed that it is more appropriate to consider 95th percentiles, rather than 90th percentile, of exposure and risk estimates for humans and ecological receptors.

EPA RESPONSE: The rationale for the selected cancer and non-cancer risk criteria, based on Agency policy, is discussed in Section 2 of the revised risk assessment. A citation to the where "point of departure" was originally defined is provided for reference. The rationale for use of 90th percentile risk generated by a Monte Carlo simulation is discussed in Section 4 of the revised risk assessment.

COMMENT: Commenters questioned the evaluation of only the reasonable maximum exposure scenario. Specifically, it was noted that the receptor placement downgradient of an unlined management unit does not represent the entire population exposure distribution. One commenter suggested that EPA clearly define the exposed population of interest.

EPA RESPONSE: In risk assessments used to develop regulations under RCRA, EPA has historically assessed potential risks resulting from a reasonable maximum exposure (RME) scenario in order to ensure that the resulting regulation is adequately protective of human health without being excessively conservative. The types of data necessary to define the exact population that relied on groundwater wells as a source of drinking water or consumes fish from impacted water bodies are not available. EPA believes that consideration of RME is a reasonable and protective alternative, given the available data. Uncertainties associated with the revised risk assessment are further discussed in Section 5 of the revised risk assessment.

COMMENT: The commenters questioned the use of data from the 1997 Exposure Factors Handbook in the development of intake rate distributions for various exposures, because more current data are currently available. Commenters recommended that EPA make updates to these parameters using more current sources of information, including the recently released 2011 Exposure Factors Handbook.[163] In addition, some commenters pointed out the potential for the available exposure factor data to underestimate or overestimate exposures. One commenter noted that the risk assessment did not fully account for the dependence of input variables (*e.g.,* the interdependence of body weight and water ingestion rates for children and link between the rate of fish consumed from a water body). Another commenter suggested that a sensitivity analysis of human health exposure factors be conducted to add to the sensitivity analysis conducted by EPA in 2009.

Regarding fish consumption rates, commenters questioned the representativeness of a fixed fish consumption rate drawn from a single

[161] U.S. EPA. 2000. *Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures.* Risk Assessment Forum, Washington, DC. August.

[162] U.S. EPA. 2003. *Human Health Toxicity Values in Superfund Risk Assessments.* Office of Solid Waste and Emergency Response Directive 9285.7–53. December.

[163] U.S. EPA. 2011. *Exposure Factors Handbook: 2011 Edition.* EPA/600/R–090/052F. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. September.

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study. It was suggested for transparency that the risk assessment provide the results of the chi-square tests to demonstrate how well the fish consumption rate data fit a log normal distribution. Additionally, it was suggested that fish consumption rates should be determined from other studies and more robust data sets. One commenter suggested the incorporation of fish consumption rates representative of subsistence fishers, such as Native American populations that harvest and consume fish as part of their native traditions and culture.

Regarding drinking water ingestion rates, one commenter voiced concern about the assumption that groundwater is the source of all drinking water. The commenter indicated that this is an overly conservative and atypical assumption, as a majority of individuals will consume liquids from other sources (*e.g.,* milk, juice, sodas, bottled water, sports and energy drinks).

EPA RESPONSE: This revised risk assessment relied on both the 1997 *Exposure Factors Handbook (EFH)* [164] and the 2008 *Child-Specific Exposure Factors Handbook* (*CSEFH*) [165] for information on human exposure factors for the U.S. population. The 2011 *Exposure Factors Handbook* [166] has been completed and updates some of the data from the 1997 EFH. During the finalization of this risk assessment, EPA released *OSWER Directive 9200.1–120.*[167] Although this document provides default exposure factors to use for point estimates, EPA is still in the process of updating the full distributions necessary for probabilistic analysis. Therefore, this risk assessment does not incorporate the data from the 2011 EFH.

Exposure data used for the fish ingestion rates are described in appendix D of the revised risk assessment. Data on site-specific fish consumption rates were not available for use in this analysis. Instead, the full distribution of fish consumption rates were drawn from a study of adult anglers from Maine that fished from streams, rivers, and ponds. Because age-specific data for children were not available, all child cohorts were assumed to consume fish at the same rate as the adult cohort. Data on fish ingestion rates for Native American subsistence fishers are currently limited and can vary widely geographically, to the point that the 2011 EFH makes no recommendation for representative values. EPA acknowledges that these issues introduce uncertainty into the analysis, which are further discussed in Section 5 of the revised risk assessment.

COMMENT: Commenters emphasized the need to update exposure factors for childhood exposures and recommended that updates include data from the 2011 EFH. One commenter stated that the risk assessment appropriately considered the potential fish exposures for children. However, they pointed out that the fish consumption rates for children should be lower than those applied for adults. Another commenter suggested that the risk assessment should provide a clear description of how the exposure duration of child cohorts were used in the risk calculations. Specifically, the commenter questioned whether exposure durations were truncated at the end of each age cohort or aged through the different cohorts.

EPA RESPONSE: The revised risk assessment makes use of the 1997 EFH [168] and the 2008 CSEFH [169] for information on human exposure factors for the U.S. population. Although, as discussed in the preamble sections above, the revised risk assessment does not incorporate data from the recent 2011 EFH,[170] all child data included in this document was derived from the 2008 EFH. In addition to child ingestion of drinking water, EPA's evaluation has been revised to also account for infant exposures that may occur from formula mixed with contaminated groundwater. These data are presented in appendix D of the revised risk assessment. Consistent with the commenter's recommendation for cohort aging, the risk assessment aged receptors through each age cohort using age-specific data for exposure factors and physical characteristics that were weighted proportionally by the corresponding time period and then summed. Specific discussion of truncation values is provided in later in this preamble.

COMMENT: Public commenters recommended updating BCF values with more current references. One commenter questioned why bioconcentration factors were zero for some constituents that are essential nutrients (*i.e.,* cobalt and copper). Another commenter voiced concern that EPA had not fully considered the appropriateness of using BCFs to describe metals bioaccumulation, suggesting that current science (including EPA guidance documents) indicates that BCFs are poor predictors of tissue metal concentrations due to wide variation in uptake patterns governed by several chemical and biological factors. Another commenter recommended the use of an approach that would be more robust than the single BCF approach, establishing and applying distributions of BCFs. This commenter also recommended that the assessment adhere to the EPA policy of using dissolved metals in the calculating the bioconcentration of metals in fish, or should provide the rationale for using a different approach.

EPA RESPONSE: EPA recognizes that the use of BCFs may not represent the most current approaches available to estimate metal bioaccumulation at individual sites, where fish tissue data can be collected. However, as noted by public commenters, BCFs are useful in a screening-level assessment and EPA believes they are also appropriate for a national-level risk assessment, where site-specific data are not available and collection of site-specific data is not viable.

In some cases, insufficient data to determine a BCF value meant that these constituents could not be quantitatively evaluated for this pathway. Regarding the concern expressed with respect to zero BCF values, the commenter did not provide alternative BCFs that EPA could consider for the constituents at issue. Additionally, EPA agrees that, given the latest scientific information, distributions of BAFs/BCFs may be better than single BAFs/BCFs because they account for changes in bioaccumulation/bioconcentration at different water concentrations. EPA is working to develop BAF/BCF distributions for several CCR pollutants of concern but does not yet have a robust enough dataset for use for the final CCR Rule. In lieu of this, EPA is proceeding with the single BAF/BCF approach for the current analysis. EPA does recognize this issue as a limitation for the BCF calculations and considers it as an uncertainty in the risk

[164] U.S. EPA. 1997. *Exposure Factors Handbook, Volume III, Activity Factors.* EPA/600/P–95/002Fa. Office of Research and Development, Washington, DC. August.

[165] U.S. EPA. 2008. *Child-Specific Exposure Factors Handbook.* EPA/600/R–06–096F. National Center for Environmental Assessment, Cincinnati, OH.

[166] U.S. EPA. 2011. *Exposure Factors Handbook: 2011 Edition.* EPA/600/R–090/052F. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. September.

[167] U.S. EPA. 2014. *Human Health Evaluation Manual, Supplemental Guidance: Update of Standard Default Exposure Factors.* OSWER Directive 9200.1–120. February.

[168] U.S. EPA. 1997. *Exposure Factors Handbook, Volume III, Activity Factors.* EPA/600/P–95/002Fa. Office of Research and Development, Washington, DC. August.

[169] U.S. EPA. 2008. *Child-Specific Exposure Factors Handbook.* EPA/600/R–06–096F. National Center for Environmental Assessment, Cincinnati, OH.

[170] U.S. EPA. 2011. *Exposure Factors Handbook: 2011 Edition.* EPA/600/R–090/052F. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. September.

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characterization. Overall, EPA agrees that the use of this older data introduces some uncertainty into the analysis. These uncertainties are discussed in greater detail in Section 5 of the revised risk assessment.

With the exception of mercury, EPA evaluated bioconcentration based on water column concentrations that include contributions from dissolved and solid phases because available BCFs represent contributions from both. Because a BAF based only on dissolved-phase concentrations was available for mercury, EPA evaluated this constituent using only dissolved concentrations. Applying this conservative approach for most constituents ensured protection of human health. Even with this conservative assumption, the 90th percentile risks for the probabilistic analysis (Section 4) did not exceed risk criteria for the fish ingestion pathway. Therefore, this approach is unlikely to have affected the principal findings of the risk assessment.

For the revised risk assessment, EPA reviewed the available literature and identified BCFs for additional constituents that previously had no values. As noted in appendix G of the revised risk assessment, the following source hierarchy was used for fish BCFs:

- Primary literature: These are generally papers focused on a single chemical [171] [172] [173] [174] or may contain data on multiple chemicals.[175] [176]
- U.S. EPA databases/publications: These included ECOTOX [177] and the Mercury Report to Congress.[178]
- Other government agency resources: These included ATSDR Toxicological Profiles [179] and the Hazardous Substances Data Bank.[180]

EPA also finds that the references provided by commenters provided primarily phytotoxicity and accumulation data for terrestrial plants, and were therefore not relevant to EPA's explicit solicitation on whether the bioconcentration factors drawn from Baes et al. (1984) should be considered in the final risk assessment.[181]

5. Comments Related to Ecological Exposure and Toxicity

COMMENT: Public commenters emphasized the potential importance of cumulative ecological risk, whereby an ecological receptor may be exposed to multiple constituents and/or pathways concurrently. For example, amphibians may be subject to both dermal and ingestion exposure. Public commenters noted that ecological risks were underestimated because the following scenarios were not considered for ecological receptors: Aboveground pathways, contaminant transport to nearby uncontaminated environments, and the inclusion of field data in the analysis.

EPA RESPONSE: EPA acknowledges that cumulative effects can be important for ecological receptors. However, just as EPA did not consider cumulative human health risks from exposures to groundwater (discussed in the previous sections of this preamble), they were not modeled for ecological receptors. In the national, probabilistic analysis (Section 4 of the revised risk assessment), risks for all constituents fell below the ecological criteria. Even the sum of modeled risks for all constituents fell below the ecological criteria. In sensitivity analyses (Section 5 of the revised risk assessment), which considered different subsets of national disposal practices that may drive risks, boron and cadmium were the two constituents found to result in risks above ecological criteria. To the extent that cumulative exposures were not evaluated, EPA acknowledges that ecological risk could be underestimated to some degree. However, these uncertainties are unlikely to affect the principal findings of the risk assessment. In addition, EPA also notes that all surface water risks are orders of magnitude lower than the risks resulting from direct discharges modeled in U.S. EPA (2013).[182]

In contrast to the surface water and sediment exposures, ecological risks for individual constituents were appreciably above risk criteria for direct exposure to impoundment wastewater. As a result, it is clear that CCR disposal in surface impoundments have the potential to pose risk to ecological receptors, even without consideration of cumulative exposures.

COMMENT: Public commenters stated that the risk assessment does not consider sensitive habitats or species. Commenters requested additional consideration of threatened and endangered species and the inclusion of ecological field data.

EPA RESPONSE: EPA did not evaluate these sensitive habitats and sensitive/endangered ecological receptors because these are inherently site-specific issues for which data on potential impacts are often not available and can be difficult to quantify, even on a site-specific basis. EPA acknowledges that the inability to quantitatively evaluate the potential for these adverse effects represents a source of uncertainty. Discussion of these uncertainties is presented in Section 5 of the revised risk assessment.

COMMENT: Public commenters were concerned that a more conservative approach was needed to derive the ecological benchmarks. Multiple commenters also stated that the use of risk attenuation factors to scale the screening risks to full-scale risks was inappropriate. Several commenters noted that the ecological boron benchmark used for surface water exposures contained incorrect units based on an incorrect transcription in the peer-reviewed article. Another commenter noted that the ecological

[171] Eisler, R. 1989. *Molybdenum Hazards to Fish, Wildlife, and Invertebrates: A Synoptic Review.* Contaminant Hazard Reviews, Report No. 19, Biological Report 85(1.19). Laurel, MD. August.

[172] Kumada, H., et al. 1973. Acute and chronic toxicity, uptake and retention of cadmium in freshwater organisms. Bull. *Freshwater Fish.* Res. Lab. 22: 157

[173] Lemly AD. 1985. Toxicology of selenium in a freshwater reservoir: implications for environmental hazard evaluation and safety. *Ecotoxicology and Environmental Safety.* 10(3): 314–338.

[174] Murphy, B.R., G.J. Atchison, and A.W. McIntosh. 1978. Cadmium and zinc in muscle of bluegill (Lepomis macrochirus) and largemouth bass (Micropterus salmoides) from an industrially contaminated lake. *Environmental Pollution* 17:253–257.

[175] Barrows ME, Petrocelli SR, Macek KJ, Carroll JJ. 1980. Bioconcentration and elimination of selected water pollutants by bluegill sunfish (Lepomis macrochirus). In: Haque R, ed. Dynamics, exposure and hazard assessment of toxic chemicals. Ann Arbor, Michigan, U.S.A.: American Chemical Society. p. 379–392.

[176] Stephan, C.E. 1993. Derivation of Proposed Human Health and Wildlife Bioaccumulation Factors for the Great Lakes Initiative. Draft. Environmental Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, Duluth, MN. March.

[177] U.S. EPA (Environmental Protection Agency). 2009b. EC*OTOX User Guide: ECOTOXicology Database System.* Version 4.0. Available online at *www.epa.gov/ecotox/.*

[178] U.S. EPA (Environmental Protection Agency). 1997d. *Mercury Study Report to Congress. Volume III—Fate and Transport of Mercury in the Environment.* EPA 452/R–97/005. Office of Air Quality Planning and Standards and Office of Research and Development, Washington, DC.

[179] ATSDR (Agency for Toxic Substances and Disease Registry). 2008. Minimal Risk Levels (MRLs) for Hazardous Substances. Available at *www.atsdr.cdc.gov/mrls.html.*

[180] U.S. NLM (National Library of Medicine). 2011. *Hazardous Substances Data Bank (HSDB).* Available online at: *toxnet.nlm.nih.gov/cgi-bin/sis/htmlgen?HSDB.*

[181] Baes, C.F., III, R.D. Sharp, A.L. Sjoreen, and R.W. Shor. 1984. *A Review and Analysis of Parameters for Assessing Transport of Environmentally Released Radionuclides Through Agriculture.* ORNL–5786. Oak Ridge National Laboratory, Oak Ridge, TN. September.

[182] U.S. EPA. 2013. Environmental Assessment for the Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category. EPA–821–R–13–003. Office of Water. Washington, DC 20460. April.

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cadmium benchmark used for direct contact with surface water was incorrect.

EPA RESPONSE: Ecological benchmarks were obtained for CCR constituents when available and compared with the modeled media concentrations (*e.g.,* surface water, sediment) to estimate the HQs used to characterize ecological risk. These benchmarks represent the best available estimates of receptor responses based "no effects" (NOAEL) or "lowest effects" (LOAEL) study data. In some scenarios, these benchmarks may represent species not actually present in the field. In others, these benchmarks may not capture the most sensitive possible receptor at every site or for each constituent. While some benchmarks have factors of safety included to account for these or other uncertainties, there remains the potential for these ecological benchmarks to underestimate risks for the specific species and communities that live in surface waters impacted by CCR WMUs. The magnitude of this uncertainty is unknown. Consideration of any additional sensitive species not captured by the current benchmarks may result in some additional constituents above risk criteria in the probabilistic analysis. EPA notes that ecological risks to some of these additional sensitive receptors may be reflected in damage cases. However, this site-specific uncertainty is unlikely to affect the national conclusions of the risk assessment.

Regarding incorrect benchmark values, an updated boron benchmark was used in the revised risk assessment. The units in the fish study from which the previous SCV was derived [183] had been erroneously transcribed in Suter and Tsao (1996) [184] as µg/L instead of mg/L. The updated SCV was recalculated using the corrected units. The revised value has been corroborated with the authors. Additionally, a continuous criteria concentration (CCC) was used for the cadmium surface water benchmark in the revised risk assessment, replacing the previous value. The updated values are presented in appendix E of the revised risk assessment report.

[183] Hamilton, S.J. 1995. Hazard assessment of inorganics to three endangered fish in the Green River, Utah. *Ecotoxicol Environ Saf 30*:134–142.

[184] Suter, G.W., and C.L. Tsao. 1996. *Toxicological Benchmarks for Screening Potential Contaminants of Concern for Effects on Aquatic Biota: 1996 Revision.* U.S. Department of Energy, Oak Ridge National Laboratory, Oak Ridge, TN. June.

6. Comments Related to the Monte Carlo Analysis Approach

COMMENT: While some public commenters stated that the human health probability distributions appeared appropriate, others expressed concern regarding a conservative bias in input parameter probability distributions used and the resulting potential for overestimation of risks. These commenters noted that the ideal approach would be to estimate the actual risk and associated uncertainty rather than weighting the results conservatively.

EPA RESPONSE: The revised risk assessment conducted a full-scale, probabilistic Monte Carlo analysis to quantify human and ecological risks. EPA agrees it would be ideal to produce best estimates of actual risk. All input data distributions (*e.g.,* aquifer data, soil type, WMU data, climate data, distance to groundwater wells, distance to surface water bodies, constituent concentrations, water flow data, human exposure factors) were developed in line with this objective. However, these distributions were developed from available data and are subject to the limitations of these data. In cases where data were not sufficient to fully characterize the input distribution, conservative values and assumptions were used to fill data gaps to remain protective of human health and the environment. Further discussion of these uncertainties has been added to Section 5 of the revised risk assessment.

COMMENT: Public commenters pointed out that the risk assessment does not formally differentiate variability from uncertainty or show confidence limits for risk results, which makes it challenging to identify opportunities to reduce uncertainty. One commenter requested that EPA discuss the implications of the relatively wide risk distributions, including the reasons why some risk distributions are larger than others based on the Monte Carlo results.

EPA RESPONSE: EPA acknowledges it would be ideal to separate variability from uncertainty when possible in a probabilistic risk assessment. EPA was able to reduce a substantial number of the uncertainties in the revised risk assessment through the acquisition of additional data on facilities, environmental parameters, and constituent concentrations. Variability and uncertainty are still comingled in a large number of cases due to remaining data gaps; however, EPA conducted multiple sensitivity analyses to determine the potential for different inputs to affect risk results. Additional discussion of the differences between parameter variability, data uncertainty, and model error, as well as discussions of the sensitivity and uncertainty analyses, is presented in Section 5 of the revised risk assessment.

EPA disagrees that there are wide risk distributions. While the commenter correctly points to other risk assessments that had closer central tendency and high-end results, those were either site-specific assessments or involved no fate or transport modeling. National-scale risk assessments will necessarily have wider variability in their results compared to risk assessments that are specific to a single site. Thus, the "wider" risk distributions simply reflect the fact that different sites with different CCR can have very disparate impacts on human health and the environment.

7. Miscellaneous Comments

COMMENT: Some commenters stated that the documentation is incomplete and that an independent reviewer could not reproduce the analysis. Another commenter performed an independent review and cancer risk estimate and noted that the EPA used a reasonable approach for calculating cancer cases in the risk assessment.

EPA RESPONSE: EPA acknowledges that the documentation of the inputs and intermediate outputs could have been more transparent for the 2010 Draft Risk Assessment. In the revised risk assessment, many of the inputs EPA used are directly discernible from the appendices. A summary of the data available in each appendix is presented in Section 1 of the revised risk assessment. EPA also acknowledges that the additions and discussions of inputs in the document were not sufficient for complete duplication of the results. Thus, the input and output files for the draft risk assessment were made available in the docket of the proposed rule via an FTP site,[185] and final input and output files are being placed in the docket for the final rule.

COMMENT: Commenters requested improvement on the graphical presentation of risk results. Additionally, commenters requested further explanation of the minimum and maximum truncating values, as truncated values may reduce risk estimates.

EPA RESPONSE: While EPA did not provide a graphical presentation of the risk results, this information is more clearly discernible from the full input and output files. For discussion of the

[185] Available online at: *ftp://ftp.epa.gov/coal-combustion-residues.*

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full inputs and outputs files, see the responses in the preamble section above. With regard to truncation, EPA no longer manually truncates input distributions for the human exposure factors. Instead, exposure factor distributions in the revised risk assessment were generated with the @ Risk software (Palisade Co., Newfield, NY),[186] as described in appendix D. EPA has also added further discussion of the cohorts to revised risk assessment, with tables comparing each cohort's risk presented in Section 5 of the revised risk assessment.

COMMENT: Commenters requested more complete documentation of the sensitivity analysis. Other comments included a request to add human health exposure factor variables to the sensitivity analysis, and to conduct additional sensitivity analyses on different topics (*e.g.,* well distance distribution).

EPA RESPONSE: EPA acknowledges the omission of the original sensitivity analysis from the docket. EPA updated the sensitivity analysis[187] so that it clearly describes the methodology that underlies the results summarized in Section 5 of the revised risk assessment. This sensitivity analysis was placed in the docket for the proposed rule.

Human health exposure factor variables were not evaluated in the sensitivity analysis. Human exposure factor variables have well-established, peer-reviewed, national distributions that are regularly used in probabilistic risk analyses conducted by EPA based on Agency policy. Therefore, the contribution of variability in the exposure factors to the variability in risk was not particularly useful for understanding the aspects of CCR disposal practices that may drive risk. Additional sensitivity analyses such as leachate duration versus leachable content and liner performance by thickness were conducted in the revised risk assessment and are summarized in Section 5.

### *B. Summary of Risk Assessment and Results*

#### 1. Problem Formulation

EPA first developed conceptual models to illustrate a general layout of surface impoundments and landfills, the chemical constituents that may be released from these WMUs, the routes through which these constituents may migrate through environmental media, and the types of exposures that may result. These conceptual models were used as the basis for all subsequent data collection efforts. EPA first collected data on the coal-fired power plants and CCR WMUs located across the United States. EPA then collected regional and national data to characterize the environment and receptor population surrounding each WMU. The data assembled represent the most current and comprehensive information available to the Agency at the time this risk assessment was conducted. Using the data collected, EPA first conducted a simplified hazard identification to determine which constituents warranted further evaluation. At this stage, EPA considered the presence of a constituent in CCR waste, combined with the availability of at least one toxicity benchmark, sufficient evidence of hazard potential. Table 1 presents a summary of the different chemical constituents retained as constituents of potential concern (COPCs) for further analysis.

TABLE 1—LIST OF CHEMICAL CONSTITUENTS EVALUATED IN THE CCR RISK ASSESSMENT

| |
|---|
| Aluminum |
| Ammonia |
| Antimony |
| Arsenic |
| Barium |
| Beryllium |
| Boron |
| Cadmium |
| Calcium |
| Chloride |
| Chromium |
| Cobalt |
| Copper |
| Fluoride |
| Iron |
| Lanthanum |
| Lead |
| Lithium |
| Magnesium |
| Manganese |
| Mercury |
| Molybdenum |
| Nickel |
| Nitrate/Nitrite |
| Selenium |
| Silicon |
| Silver |
| Sodium |
| Strontium |
| Sulfate |
| Sulfide |
| Thallium |
| Uranium |
| Vanadium |
| Zinc |

All risks identified in subsequent analyses were compared against risk criteria of cancer risk greater than $1 \times 10^{-5}$ or a noncancer hazard quotient (HQ) greater than 1. EPA typically relies on a risk range to determine the point at which regulation is appropriate. EPA uses as an initial cancer risk "level of concern" a calculated risk level of $1 \times 10^{-5}$ (one in one hundred thousand) or an HQ above 1.0 for any noncarcinogens. For example, waste streams for which the calculated high-end individual cancer-risk level is $1 \times 10^{-5}$ or higher generally are considered candidates for regulation. Waste streams whose risks are calculated to be $1 \times 10^{-4}$ or higher generally will be considered to pose a substantial present or potential hazard to human health and the environment and generally will be regulated. Waste streams for which these risks are calculated to be $1 \times 10^{-6}$ or lower, and lower than 1.0 HQs or EQs for any noncarcinogens, generally will be considered not to pose a substantial present or potential hazard to human health and the environment and generally will not regulated. See 59 FR 66075–66077, December 22, 1994.

#### 2. Screening Analysis

EPA conducted separate screening analyses for each exposure pathway to identify which COPCs are most likely to pose risk to receptors. The results of this screening generally do not provide a precise characterization of individual risks that may occur, but rather identify those COPCs that are most likely to exceed risk criteria. In cases where well established, post-construction management practices ("controls") have been shown to minimize releases from WMUs, EPA considered exposures for both an uncontrolled and controlled management scenario.

This screening analysis identified potential risks to human and ecological receptors resulting from the releases of particulate matter and the chemical constituents contained therein through wind and run-off. Under an uncontrolled management scenario, risks to human receptors resulted from the inhalation of windblown particulates in ambient air and the ingestion of soil and animal products (*i.e.,* meat and dairy), while risks to ecological receptors resulted from exposures to soil and sediment. Under a controlled management scenario, which consisted of fugitive dust controls and run-on/run-off controls, all risks associated with these exposure pathways decreased to below the criteria. Due to the conservative nature of the screening, there is a great deal of uncertainty surrounding the specific risks calculated for these exposure pathways. These risks represent a protective, but unlikely, combination of conditions that reflect at least an upper

[186] Available online at: *www.palisade.com/risk/.*

[187] U.S. EPA. 2009. *Sensitivity Analysis for the Coal Combustion Waste Risk Assessment.* Draft Technical Report. Prepared by RTI International for U.S. EPA, Office of Solid Waste, Washington, DC.

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bound on potential exposures. Thus, the cumulative effect of these uncertainties results in an overestimation of nationwide risks to most or all receptors. Therefore, EPA makes no direct findings concerning the magnitude of the risks that may occur under either an uncontrolled or controlled management scenario, but concludes with a high degree of confidence that the reductions achievable with standard management practices are sufficient to be protective even under this conservative screening assessment. Based on these lines of evidence, EPA concluded that no further characterization was warranted for these exposure pathways.

These screening analyses identified potential risks to human and ecological receptors from leaching of chemical constituents from CCR waste into surrounding environmental media. Risks to human health resulted from ingestion of groundwater and fish, while risks to ecological receptors resulted from exposure to surface water. There was no simple method to estimate the effect controls may have for these pathways. However, considerable dilution and attenuation may occur before COPCs reach downgradient private wells and surface water bodies. Therefore, EPA retained all of the COPCs found to be above risk criteria in groundwater and surface water for further characterization. In addition, EPA used the uncontrolled screening results for the above ground sediment pathway as a conservative proxy for the groundwater to surface water sediment pathway. As a result, sediment exposures of four COPCs were retained for further characterization. Table 2 presents a summary of the chemical constituents retained as COPCs for each pathway.

TABLE 2—LIST OF CHEMICAL CONSTITUENTS RETAINED FOR PROBABILISTIC ANALYSIS

| Human health | | Ecological | |
|---|---|---|---|
| Ingestion of groundwater | Ingestion of fish | Surface water exposure | Sediment exposure |
| Antimony | Arsenic | Aluminum | Antimony |
| Arsenic | Cadmium | Arsenic | Arsenic |
| Boron | Mercury | Barium | Silver |
| Cadmium | Selenium | Beryllium | Vanadium |
| Cobalt | Thallium | Boron | |
| Fluoride | | Cadmium | |
| Lead | | Chloride | |
| Lithium | | Chromium | |
| Molybdenum | | Cobalt | |
| Thallium | | Copper | |
| | | Iron | |
| | | Lead | |
| | | Molybdenum | |
| | | Nickel | |
| | | Selenium | |
| | | Silver | |
| | | Vanadium | |
| | | Zinc | |

These screening analyses also identified potential risks to ecological receptors from direct exposure to impoundment wastewater. Unlike the other exposure pathways, no dilution or attenuation will occur within impoundment wastewater prior to ecological exposures. Thus, the direct exposures considered in the screening analysis provide a reasonable estimate of the relative magnitude of risks. Based on the screening analyses, EPA concluded that HQs for ecological receptors exceeded 1 for the following constituents (listed from highest to lowest potential): Arsenic (100), barium (50), aluminum (30), boron (30), selenium (20), cadmium (10), vanadium (10), beryllium (2), chloride (2) and chromium (2). Because the screening analysis provides sufficient characterization of these exposures, this pathway was not carried forward for further analysis.

3. Probabilistic Analysis

EPA conducted a national-scale, probabilistic analysis to better characterize the potential risks to human and ecological receptors associated with leachate released from surface impoundments and landfills. The specific exposure routes evaluated for these releases were human ingestion of groundwater used as a source of drinking water and fish caught from freshwater lakes or streams, as well as ecological contact with and ingestion of surface water and sediment. A combination of models was used to predict COPC fate and transport through the environment, receptor exposures, and the resulting risks. Site-specific data were used, supplemented by regional and national data sets, to capture the national variability of disposal practices, environmental conditions and receptor behavior. EPA modeled risks for both highly exposed individuals (90th percentile risks) and more moderately exposed individuals (50th percentile risks). In instances where the speciation of a COPC has been shown to greatly affect fate and transport, EPA modeled multiple species to provide a bounding on potential exposures.

Table 3 shows the 90th percentile human health risks to the most sensitive age cohorts for constituents that exceeded the risk criteria. Risks are presented for arsenic modeled entirely as two different species (III and V) to provide a bounding on potential risks. Values that exceed the selected risk criteria are shown in bold. No 90th percentile risks above ecological criteria were identified for either surface impoundment or landfills. No 50th percentile risks above human health or ecological criteria were identified for either surface impoundment or landfills.

TABLE 3—90TH PERCENTILE NATIONWIDE PROBABILISTIC RISK RESULTS

| COPC | Ingestion of groundwater | |
|---|---|---|
| | Surface impoundments | Landfills |
| **Cancer Risks** | | |
| Arsenic III ..... | $2 \times 10^{-4}$ | $5 \times 10^{-6}$ |
| Arsenic V ..... | $1 \times 10^{-5}$ | $7 \times 10^{-8}$ |
| **Noncancer Risks** | | |
| Arsenic III ..... | 5 | 0.1 |
| Arsenic V ..... | 0.4 | <0.01 |
| Lithium ..... | 2 | [a] |
| Molybdenum | 2 | <0.01 |

[a] Leachate data were not available to model this COPC for landfills.

• Surface Impoundments:

Ingestion of groundwater was the only exposure pathway that resulted in risks above $1 \times 10^{-5}$. 90th percentile cancer risks above $1 \times 10^{-5}$ were identified for arsenic III ($2 \times 10^{-4}$). The 90th percentile noncancer risks above an HQ of 1 were identified for arsenic III (5), lithium (2), and molybdenum (2).

• Landfills:

All 90th percentile cancer and noncancer risks were below human health criteria.

High-end risks identified for surface impoundments are consistently higher than those for landfills. These results are attributed to the higher infiltration rates through surface impoundments, which are driven by the hydraulic head of the ponded water. Median risks for both surface impoundments and landfills were substantially lower than both the high-end risks in this risk assessment and the median risks modeled in the 2010 Risk Assessment. This decrease is attributed primarily to the interception of groundwater by surface water bodies, which is accounted for in the revised risk assessment to provide a more accurate mass balance of constituent mass during transport. It is common for coal-fired utilities to be located near water bodies, which are used as a source of cooling water and conveyance of waste. As a result, in the majority of model iterations, the interception of groundwater by surface water bodies resulted in negligible downstream well concentrations.

Based on the results of the probabilistic analysis, EPA concludes that leaching from CCR waste management units has the potential to pose risk to receptors. Arsenic, lithium, and molybdenum are the chemical constituents found to pose the greatest risks from surface impoundments, while arsenic posed the greatest risks from landfills. Available toxicological profiles indicate that risks from arsenic ingestion are linked to an increased likelihood of cancer in the skin, liver, bladder and lungs, as well as nausea, vomiting, abnormal heart rhythm, and damage to blood vessels;[188] risks from lithium ingestion are linked to neurological and psychiatric effects, decreased thyroid function, renal effects, cardiovascular effects, skin eruptions, and gastrointestinal effects;[189] and risks from molybdenum ingestion are linked to higher levels of uric acid in the blood, gout-like symptoms, and anemia.[190]

4. Sensitivity and Uncertainty Analysis

The modeled probabilistic risks capture the range of current, nationwide CCR disposal practices. However, because of the broad scope of the analysis, there are a number of sources of variability and uncertainty present. Therefore, to confirm the results of the probabilistic analysis and to better understand whether any particular subset of disposal practices drives the risks identified, EPA conducted additional sensitivity and uncertainty analyses.

EPA reviewed the models used, as well as the data and assumptions input into these models, to better understand the sources of variability and uncertainty inherent in the probabilistic analysis. The Agency then qualitatively and, to the extent possible, quantitatively analyzed these sources to understand the potential effects each may have on the modeled risk results. During this review, specific attention was focused on the parameters shown to have the greatest influence on model results. As a further method of validation, EPA compared the results of the sensitivity and uncertainty analyses with proven and potential damage cases. Together these analyses and comparisons show that there is a high degree of confidence in the principal findings of the probabilistic analysis. However, the review of sensitive parameters revealed some specific disposal practices that may result in greater risks than identified in the probabilistic modeling.

Through these additional sensitivity and uncertainty analyses, which explored different subsets of national disposal practices, EPA identified the potential for higher risks than those identified in the broader, national analysis. In particular, consideration of different waste pH values showed higher risks for arsenic at more acidic and basic pH values, as well as additional risks for boron, cobalt, fluoride and mercury at these more extreme pH values. Consideration of specific liner types showed that groundwater risks are driven by disposal in unlined units and, in particular, unlined surface impoundments. For these units, EPA identified higher risks for arsenic, lithium, and molybdenum, as well as additional risks for thallium. Clay-lined units were found to pose lower risks than unlined units. Composite-lined units were found to be the most protective disposal practice, resulting in risks far below all criteria identified in this risk assessment.

*C. Conclusions*

Based on the analyses presented in this document, EPA concludes that current management practice of placing CCR waste in surface impoundments and landfills poses risks to human health and the environment within the range that OSWER typically regulates. On a national scale, surface impoundments presented higher risks than landfills. Risks to ecological receptors were identified from exposures to aluminum, arsenic, barium, beryllium, boron, cadmium, chloride, chromium, selenium and vanadium through direct exposure to impoundment wastewater. Risks to residential receptors were identified primarily from exposures to arsenic, lithium, and molybdenum in groundwater used as a source of drinking water, but additional risks from boron, cadmium, cobalt, fluoride, mercury and thallium were identified for specific subsets of national disposal practices.

Sensitivity analyses on liner type indicate that disposal of CCR wastes in unlined surface impoundments and landfills presents the greatest risks to human health and the environment. As modeled, the national risks from clay-lined units are lower than those for unlined units, but such units can exceed risk criteria at individual sites. Composite liners were the only liner type modeled that effectively reduced risks from all pathways and constituents far below human health and ecological criteria in every sensitivity analysis conducted. Sensitivity analyses on waste type indicate that the acidic conditions that result from codisposal of CCR waste with coal refuse and the basic conditions that result from disposal of FGD waste result in higher

[188] Profile for arsenic available online at: *www.epa.gov/iris/subst/0278.htm* and *www.atsdr.cdc.gov/toxprofiles/tp2.pdf.*

[189] Profile for lithium available online at: *hhpprtv.ornl.gov/issue_papers/Lithium.pdf.*

[190] Profile for molybdenum available online at: *www.epa.gov/iris/subst/0425.htm.*

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risks from arsenic and other constituents than CCR waste disposed alone.

The risk results are consistent with the groundwater damage cases compiled by EPA. These damage cases were primarily associated with unlined units and were most frequently associated with releases of arsenic. Recent surveys of the industry indicate the majority of newly constructed units are lined, and that that the practice of codisposal with coal refuse has declined. However, this risk assessment presents a static snapshot of current disposal practices. While newer units may be managed in a more protective manner, older units, which still comprise the majority of current units, continue to operate in a manner that poses risks to human health and the environment that OSWER typically regulates.

## XI. Summary of Damage Cases

EPA has a long history of considering damage cases in its regulatory decisions under RCRA. As discussed earlier in this preamble, the statute specifically directs EPA to consider "documented cases in which danger to human health and the environment from surface run-off or leachate has been proved," in reaching its Regulatory Determination for these wastes, demonstrating that such information is to carry great weight in decisions under this section. 42 U.S.C. 6982(n)(4). Damage cases, even if only potential damage cases, are also relevant under the third Bevill factor: "potential danger, if any, to human health and the environment from the disposal and reuse of such materials." 42 U.S.C. 6982(n)(4). In addition, damage cases are among the criteria EPA must consider under its regulations for determining whether to list a waste as a "hazardous waste." See 40 CFR 261.11(a)(3)(ix). Damage cases generally provide extremely potent evidence in hazardous waste listings. In this regard, EPA notes that the number of damage cases collected for this rulemaking (157) is by far the largest number of documented cases in the history of the RCRA program.

EPA considers that both proven and potential damage cases provide information directly relevant to this rulemaking. First, damage cases provide evidence of both the extent and nature of the potential risks to human health and the environment. The primary difference between a proven and a potential damage case is whether the contamination has migrated off-site of the facility. But the mere fact that groundwater contamination has not yet migrated off-site does not change the fact that a potentially harmful constituent has leached from the unit into groundwater. Whether the constituent ultimately causes further damage by migrating into drinking water wells does not diminish the significance of the environmental damage caused to the groundwater under the site, even where it is only a future source of drinking water. As EPA explained in the preamble to the original 1979 open dumping criteria, which are currently applicable to these facilities, EPA is concerned with groundwater contamination even if the aquifer is not currently used as a source of drinking water. Sources of drinking water are finite, and future users' interests must also be protected. (See 44 FR 53445–53448.) ("The Act and its legislative history clearly reflect Congressional intent that protection of groundwater is to be a prime concern of the criterion. . . . EPA believes that solid waste activities should not be allowed to contaminate underground drinking water sources to exceed established drinking water standards. Future users of the aquifer will not be protected unless such an approach is taken.")

In the June 21, 2010 proposed rule, EPA presented for public comment an assessment of CCR damage cases, and requested comments and other information related to damage cases EPA had previously received from industry, environmental groups, and citizen groups. EPA later requested public comment on additional damage case information in a Notice of Data Availability (NODA) published in the **Federal Register** on October 12, 2011 (76 FR 63252). As discussed in Section IV of this preamble, the Agency is deferring making a Bevill determination; however, EPA is still presenting its findings with regard to damage cases (including information submitted during the comment periods for the June 2010 proposal and the October 2011 NODA) because as described above, this information supports actions taken in the present final rule.[191]

### *A. Damage Cases Presented in June 21, 2010 Proposed Rule*

In the June 2010 proposed rule, the Agency summarized its database on damage cases that had expanded since the May 2000 Regulatory Determination.[192] This summary included two cases of CCR slurry spill caused by surface impoundment dike failures (the 2005 Martins Creek, Pennsylvania, and the 2008 TVA Kingston, Tennessee), and two cases involving structural fill (the use, between 1995–2007, of CCR in the reclamation of two sand and gravel pits in Gambrills, Maryland; and for contouring the Battlefield Golf Course, in Chesapeake, Virginia, in the early 2000s). In the June 2010 proposed rule, the Battlefield Golf Course site was designated as a potential damage case, whereas the other three sites were designated as proven damage cases.[193]

### *B. Additional Information and Studies*

Shortly prior to the publication of the June 2010 proposed rule and immediately thereafter, several stakeholder groups provided the Agency with new information on damage cases. In November 2009, the Electric Power Research Institute (EPRI) issued a two-volume draft report[194] analyzing the 24 proven and 43 potential damage cases established in EPA's 2007 damage case report[195] accompanying the August 2007 Notice of Data Availability (NODA).[196] EPRI claimed that in the great majority of damage cases there is no record of primary MCL contaminants migrating off-site that would justify designating them as proven damage cases. EPRI also disagreed with several ecologic damage cases that had been predicated on fish advisories in Texas, on the grounds that the selenium toxicity standard that triggered these fish advisories was later revised by the state, and subsequently the fish advisories were rescinded. In February and August 2010, The Environmental Integrity Project (EIP), jointly with other citizen groups, issued two reports, identifying 70 alleged damage cases.[197] [198] Fifty of these cases were submitted to EPA for the first time.

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[191] Damage Case Compendium (Technical Support Document on Damage Cases), U.S. EPA, December 2014.

[192] See June 21, 2010 **Federal Register**—Appendix to the Preamble: Documented Damages from CCR Management Practices (75 FR 35230).

[193] See 75 FR at 35131 for definitions of "proven" and "potential" damage cases.

[194] *Evaluations of CCP Damage Cases:* These two volumes were finalized in July and September 2010, respectively: *http://my.epri.com/portal/server.pt?open=512&objID=413&&PageID=230509&mode=2&cached=true.*

[195] *Coal Combustion Waste Damage Case Assessments,* July 9, 2007. EPA–HQ–RCRA–2006–0796–0015.

[196] Notice of Data Availability on the Disposal of Coal Combustion Wastes in Landfills and Surface Impoundments, 72 FR 49714, August 29, 2007.

[197] *In Harm's Way: Lack of Federal Coal Ash Regulations Endangers Americans and Their Environment.* Environmental Integrity Project, Earthjustice, and Sierra Club: *http://www.environmentalintegrity.org/news_reports/08_26_10.php.*

[198] *Out of Control: Mounting Damages from Coal Ash Waste Sites.* Environmental Integrity Project and EarthJustice: *http://www.environmentalintegrity.org/news_reports/news_02_24_10.php.*

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In response to EPRI's report, EPA reassessed the 24 proven damage cases identified in EPA's 2007 Damage Case report, as well as three additional proven damage cases cited in the proposed rule. In addition, in response to EIP's reports, the Agency assessed the 70 alleged damage cases, to independently confirm the allegations in the report. In reviewing [199] these alleged damage cases, EPA took a number of measures. First, to the extent the information was available, EPA consulted tabulated monitoring well data to validate the exceedance data presented in comments; and studied well- and waste-unit location maps, geohydrologic studies, and groundwater potentiometric maps to validate both whether the wells were up-gradient or down-gradient wells and instances of groundwater mounding. EPA also contacted state regulators to confirm the reports' claims of contamination, particularly contamination exceeding state or federal water quality standards, and conducted internet research (focusing on state regulatory information) pertaining to the sites in question. EPA also thoroughly assessed state comments submitted to EPA in response to the June 2010 proposed rule and the October 2011 NODA. Third, EPA identified state or federal administrative measures applied to utilities (*e.g.,* consent orders, notices of violation, penalties for non-compliance, etc.) and/or legal motions (*e.g.,* law-suits, motions for injunctive relief, and out-of-court settlements) filed by the states or citizen groups in order to identify any instances of non-compliance by the utilities that have resulted in documented impacts to water resources.

EPA's review confirmed that 13 of the 27 damage cases previously designated as proven did meet the criteria used by EPA for identifying proven damage cases; however, EPA also found that six of the 27 cases only meet the criteria for a potential damage case, while the remaining eight cases were altogether rejected (*i.e.,* EPA determined that a damage case has not occurred, and/or test of proof criteria were not satisfied, and/or CCR was not the only or predominant waste component). Regarding the 70 alleged damage cases in the two EIP reports, EPA concluded that ten of them qualify as proven damage cases, 45 as potential damage cases, and the remainder were either rejected or, due to the lack of adequate information, defined as indeterminate.

In November 2011, the Utility Solid Waste Activities Group (USWAG) submitted to the docket of the October 2011 NODA a critical review of EIP's 70 alleged damage cases from 2010. USWAG's review concluded that "the overwhelming majority of the allegations regarding the 70 sites . . . fail to provide the requisite 'test of proof' documentation necessary for EPA to characterize virtually any of the sites as proven damage cases." Also, in November 2011 EIP submitted to the docket of the October 2011 NODA a report alleging 20 new damage cases.[200]

Following review of the comments on the proposed rule and the October 2011 NODA, EPA has revisited some of its earlier damage case findings. Our post-proposal studies have resulted in: (1) Rejection of 17 of the previously-established and newly-alleged damage cases, either due to inappropriate scope (*e.g.,* oil combustion waste, non-utility CCR, or CCR disposed-off in abandoned coal mine pits), co-mingling with non-CCR waste, or inadequate information to ascertain that contaminants are derived from CCR; (2) two of the damage cases that had been previously designated as 'rejected' in EPA's 2007 damage case report were re-categorized as proven damage cases and six others were re-categorized as potential damage cases; and (3) one damage case site reported in *Risky Business* occurred next to a site that had already been previously reported.

In summary, at the present time the Agency has established 40 proven and 113 potential damage cases. In addition, the rulemaking docket contains four additional, state-endorsed damage cases from Wisconsin. While EPA has insufficiently-detailed information (including the extent, if any, that the contaminants have migrated off site) to designate these four additional sites as potential or proven, because the state has identified them to us as damage cases, we have included them in our overall total of 157.

### *C. Stakeholder Comments on Damage Cases*

All of the comments submitted by stakeholders to the dockets of the proposed rule and the October 2011 NODA, as well as EPA's responses, are included in the Technical Support Document to CCR Damage Cases which is available in the RCRA docket supporting this rule. The following is a summary of the salient comments submitted by the various stakeholder groups.

#### 1. Utility Industry's Comments

EPA received several comments from utilities arguing that an incident should not be considered to be a "damage case" if the environmental damage has been addressed or is no longer occurring and/or if the State Director is satisfied that no further action is required. (Note: For those damage cases known to the Agency prior to EIP's 2010 reports, remediation is completed or underway at *all* sites where remediation was known to be required.) These commenters also argued that EPA should disregard cases in which there are no downstream contaminant receptors to be harmed by the contamination. These commenters also alleged that only "proven" damage cases should be considered to be relevant as only these are "*documented cases in which danger to human health or the environment from surface runoff or leachate has been proved,*" 42 U.S.C. 6982(n)(4).

Industry commenters also made a number of other points. They stated that most damage cases occurred in older facilities commissioned before current state landfill regulations were promulgated, where most waste units lack liners and leachate collection systems, and that in most cases, exceedances of state or federal water quality standards were contained on site, and these exceedances are mostly for constituents (*e.g.,* sulfate and boron) that do not have federal, health-based drinking water quality standards. These commenters also claimed that the number of proven damage cases is very sparse: Of the 24 proven damage cases in EPA's 2007 report,[201] they argued that only three had documented off-site groundwater exceedances of health-based MCLs that can be attributed to CCR impacts. They also claimed that of the 70 alleged damage cases in EIP's 2010 reports (*In Harm's Way* and *Out of Control*), 64 did not meet EPA's "test of proof" criteria for characterizing the site as a proven damage case. For the remaining six sites, where the allegations on their face arguably met EPA's definition of a proven damage case, these commenters claimed that these cases should be discounted because they involved sites that are either no longer active or where the damages had been already remediated

[199] See *Assessment of Previously Identified Proven Damage and Recently Alleged Damage Cases,* October 2010.

[200] EPA–HQ–RCRA–2011–0392–0259. Nineteen of the cases involve groundwater impact, and one involves soil contaminated by the placement of coal ash and clinkers from train engine boilers for railroad tracks bed. A hard copy of the report, *Risky Business: Coal Ash Threatens America's Groundwater Resources at 19 More Sites,* was issued on December 12, 2011.

[201] *Coal Combustion Waste Damage Case Assessments,* ibid.

or are undergoing remediation with federal/state oversight. These commenters also said that 12 of the 70 EIP-alleged damage cases were previously addressed in EPA's 2007 Damage Case report, and of these, five sites had been rejected by the EPA due to lack of evidence of damage or lack of evidence of damage uniquely associated with CCR, and seven sites had been characterized as indeterminate due to insufficient information. According to these commenters, no new information regarding these 12 sites was contained in the two EIP reports that warrants their designation as proven damage cases.[202]

2. Individual State Comments

EPA also received a significant number of comments from individual states. In their comments, many of the states addressed selected damage cases that occurred within their jurisdiction, subject to their authority. Several states agreed with EPA's assessment of the damage cases; for instance, Wisconsin and Michigan complimented EPA's database of damage cases. Other commenters agreed with some of the newly alleged damage cases' reports of groundwater contamination exceeding regulatory standards, but disagreed with EIP's conclusions that enforcement was inadequate, tardy, or absent. According to some state commenters, enforcement was not necessary or appropriate in those instances. For example, some states (*e.g.,* North Carolina, Oklahoma, Tennessee, and Florida) argued that the contamination did not pose public health risks because the contaminants were confined to state-established Compliance Boundaries (known also as Groundwater Mixing Zones) [203] and/or because there was no evidence the contamination had migrated off-site. Several other states (*e.g.,* Maryland, Virginia, and Texas) confirmed EPA's established damage cases as well as some of the newly alleged damage cases, but claimed that these cases were associated with presently outdated practices, and that regulatory requirements have since been revised to prohibit such practices. Two states (South Dakota and Pennsylvania) confirmed that contamination above federal or state regulatory standards had occurred, but attributed the contaminant(s) to sources other than CCR units, *e.g.,* coal mining pits associated with coal refuse; and/or nearby, up-gradient unlined MSWLFs, cooling water evaporation ponds, or natural background soil compositions. For certain cases, the states explained that required assessment monitoring was still ongoing to establish the source, scope, and extent of the contamination, and so had reached no conclusions about the specific allegations (North Carolina, North Dakota, and Tennessee). Finally Ohio acknowledged that the extent of groundwater contamination risk within the state is poorly-documented due to the scarcity of monitoring wells down gradient from unlined disposal units.

3. State Association Comments

The Association of State and Territorial Solid Waste Management Officials (ASTSWMO) argued that the 24 proven damage cases reported in EPA's 2007 Damage Case report do not reflect current land disposal practices, and so are irrelevant to the proposed rule. For example, disposal "units" involved in several damage cases included five sand and gravel pits, two quarries, and one lake impoundment. ASTSWMO commented that half of these sites began operating in 1970 or earlier, including at least six sites that began operating in the early 1950s. ASTSWMO claimed that much of the information cited in the two EIP 2010 alleged damage case reports is incomplete, incorrect and/or misleading. For example, their comments alleged that EIP failed to provide pertinent information on specific monitoring wells, sample/analytical dates, and hydrogeological data. ASTSWMO also claimed that many of the assumptions about groundwater flow were based on a topographic maps rather than on potentiometric maps that are based on subsurface groundwater flow data. They also claim that data in state files contradicted claims in the reports, and that EIP's reports contained numerous technical errors, such as reporting values for naturally occurring constituents as contamination, reported data without distinguishing between down-gradient and up-gradient wells, ignoring the potential contribution from sources other than CCR-related units (*e.g.,* coal mining legacy), and claims that information provided by state program staff was misconstrued/misrepresented.

4. Citizens Group Comments

Citizen groups generally argued that the fact that damage has occurred should be part of the weight of evidence documenting the potential for harm at all CCR disposal sites, without regard to whether the damage cases were categorized as "proven" or "potential." These commenters also raised a number of arguments in direct response to the comments provided by the utilities and the states. For example, these commenters argued that the presence of downstream receptors is a valid factor to consider when setting priorities for mitigating damage, but does not justify allowing contamination to migrate off of the disposal site. These commenters claimed that about one-fifth of EPA's damage cases preceding the 2010 EIP reports show evidence of contamination of private and public drinking water wells. In addition, these commenters allege that state regulatory agencies have done little to respond to contamination from CCR disposal sites, and, even in those cases where action has been taken, rarely is any action taken beyond assessment monitoring. According to these commenters, off-site monitoring has only occurred at a limited number of sites, and mostly such monitoring was performed voluntarily by the utilities and was not reported to state regulators. These commenters also claimed that although less than half of EPA's damage cases preceding the 2010 EIP reports involve active landfills, almost three-quarters of the newly alleged damage cases (EIP's 2010 reports) involve active landfills. They further alleged that a large majority of EPA's surface impoundment damage cases preceding the 2010 EIP reports are active sites, indicating that the absence of liners is contributing to the contamination problems. They noted that one quarter of the damage cases in EIP's 2010 reports involved units with liners, indicating that the mere presence of any liner provides no assurance that migration of contaminated groundwater from a waste unit is not occurring. Overall, they claimed that surface impoundments remain "woefully unregulated" when compared to landfills. Over one third of EIP's alleged groundwater damage cases show migration of contamination off-site. Also, a quarter of EPA's damage cases preceding the 2010 EIP reports involve contamination of surface water, and 15 percent of these damage cases show ecologic damage. Finally, these commenters note that several of the Secondary Contaminant Maximum Levels (SMCLs) constituents still might

[202] EPA–HQ–RCRA–2011–0392–0211, ibid.

[203] A Zone of Discharge or Zone of Mixing is a three dimensional region containing groundwater being managed to mitigate impairment caused by the release of contaminants from a waste disposal site; by definition, it is inside the detection boundary area, hence it is exempt from compliance with MCL and SMCL standards (*e.g.,* in Florida, Illinois, South Carolina, Tennessee, North Carolina, and Pennsylvania).

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cause harm to recipients residing next to CCR disposal sites.[204]

*D. Response to Key Stakeholder Comments*

In many instances EPA did not have access to information that would either substantiate or refute the claims in EIP's reports. In many instances public commenters submitted information that clarifies, rebuts or otherwise calls into question some of the allegations contained in the various damage case reports. For example, there are instances in which claims were made that a contaminant plume had migrated offsite even though there were no offsite monitoring wells to confirm the claim. Due to the dearth of groundwater monitoring on facilities' boundaries (or beyond) EPA could not identify offsite plume migration for most sites, except in the rare instances drinking water wells had been contaminated. Consequently, only 10 of the 70 alleged cases submitted by EIP in 2010 were designated as proven damage cases.

In addition, factual errors were identified in certain instances; for example, certain allegations of groundwater contamination were based on surface water standards (rather than groundwater standards). Corrections or updated facts are reflected in EPA's damage case assessment. Nevertheless, EPA was able to validate a significant number of EIP's claims; for example, as of 2011, EPA was able to confirm that a significant portion of the damage cases in EIPs 2010 report involved both landfills and surface impoundments, most of which involved units with either no liner or a substandard liner system. And for many of EIP's damage cases, EPA was able to confirm sufficient details to classify them as potential damage cases.

However, EPA disagrees with most of the arguments minimizing the significance of the damage case record. First, cases where contamination has been remediated remain relevant to this rulemaking. EPA is relying on the damage cases to evaluate the extent and nature of the risks associated with particular CCR management practices. Facts demonstrating the consequences from particular activities therefore remain relevant, particularly (although not solely) where the management practices continue to occur. In other words, what matters in this regard are facts that provide information on the reasons that unit leaked, the particular contaminants that were present, the levels of those contaminants, and the nature of any impacts caused by that contamination. None of these facts are affected by whether the damage is ultimately mitigated or remedied. This is entirely consistent with RCRA section 8002(n), which requires EPA to evaluate the "potential danger, if any, to human health and the environment from the disposal and reuse of such materials" in addition to "documented" damage cases. 42 U.S.C. 6982(n)(3)–(4). Accordingly, the fact that any contamination has subsequently been remediated is not a basis for disregarding a damage case. Moreover, EPA is not relying on these damage cases to evaluate the adequacy of state programs, although it may ultimately provide information relevant to such findings. Therefore the adequacy of the state's response, or the lack thereof, is also not relevant to whether particular damage cases are appropriately considered as part of this rulemaking.

EPA also disagrees that only the presence of receptors within the impact sphere of a contaminating facility merits consideration of a particular damage case. EPA's longstanding and consistent policy across numerous regulatory programs has been that groundwater contamination is a significant concern that merits regulatory action in its own right, whether or not the aquifer is not currently used as a source of drinking water. Sources of drinking water are finite, and future users' interests must also be protected. The absence of current receptors is therefore also not an appropriate basis on which to discount damage cases. And for all of the reasons discussed above, EPA also disagrees that only exceedances of health-based standards of contaminants that have migrated off-site (*i.e.,* only proven damage cases) should be accounted for as part of this rulemaking.

The Agency also disagrees with the claims that the number of damage cases is "sparse," the majority of which involve only "outdated CCR management practices" in older facilities, and therefore are not relevant to determining the current risks from CCR mismanagement. Even assuming that only "proven" damage cases were relevant, to date, EPA has confirmed a total of 40 proven damage cases, which is hardly "sparse." And when "potential" damage cases are considered, the totals rise to 157; this is the largest number of damage cases in the history of the RCRA program. Further, these numbers likely underestimate the true number of cases in which CCR units are contaminating groundwater. In reality, the damage case record represents only a subset of those CCR waste units that have effective groundwater monitoring. As discussed in Unit IV.A of this document, a significant portion of CCR surface impoundments still lack groundwater monitoring, and only approximately 80% of the recently commissioned impoundments (*i.e.,* since about 1994) have groundwater monitoring.

In addition, under many state programs existing impoundments are exempt from groundwater monitoring and once monitoring is put in place, new damage cases quickly emerge. This is illustrated by two lines of evidence: First, in the wake of the 2008 TVA Kingston CCR spill two states required utilities for the first time to install groundwater monitoring. Illinois required facilities to install groundwater monitoring down gradient from their surface impoundments. As a result, within only about two years, Illinois detected seven new instances of primary MCL exceedances and five additional instances with exceedances of SMCLs. The data for all twelve sites were gathered from onsite; it appears none of these facilities had been required to monitor groundwater off-site, so whether the contamination had migrated off-site is currently unknown.[205] Similarly, North Caroline required facilities to install additional down gradient wells. In January 2012, officials from the North Carolina Department of Environment and Natural Resources disclosed that elevated levels of metals have been found in groundwater near surface impoundments at all of the State's 14 coal-fired power plants.[206]

Second, states with effective programs for groundwater monitoring tend to have a larger record of damage cases (*e.g.,* Wisconsin, nationally ranked as the 32nd CCR disposer in 2011, has 14 damage cases) as compared to states with less stringent groundwater

[204] Examples include boron's One-Day and Ten-Day Health Advisory (3.0 mg/L) and the Longer Term Health Advisory (2.0 mg/L) levels for children; manganese's Long Term Health Advisory (LTHA: 0.3 mg/L) level; and sulfate's Drinking Water Advisory (DWA: 500 mg/L) level in groundwater have been exceeded each in between over 60 and close to 80 of both the alleged and damage case sites and those sites preceding the 2010 EIP reports.

[205] See EIP's December 2011 *Risky Business: Coal ash Threatens America's Groundwater Resources at 19 More Sites,* docket document EPA–HQ–RCRA–2011–0392–0259, appendix A3. *www.environmentalintegrity.org/.../121311EIPThirdDamageReport.pdf* and *Illinois EPA's Ash Impoundment Strategy Progress Reports,* February 10 and October 2011, accessed Online July 15, 2014: *http://www.epa.state.il.us/water/groundwater/publications/ash-impoundment-progress.pdf and http://www.epa.state.il.us/water/ash-impoundment/documents/ash-impoundment-progress-102511.pdf.*

[206] Groundwater Monitoring Data for Coal Ash Ponds, NC DENR: *http://portal.ncdenr.org/web/wq/hot-topics/coalashregulation/gwatermonitoring.* Accessed Online July 15, 2014.

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monitoring requirements (*e.g.,* Texas, nationally ranked as the second largest CCR disposer in 2011, has only three confirmed, potential damage case).

Nor is it accurate that the majority of these damage cases involve older units that no longer reflect current management practices or state requirements. The commenters point to the fact that the majority of cases involve units constructed before current state landfill regulations were promulgated, and thus lack liners and leachate collection systems. EPA agrees that the majority of cases do involve such units, but this hardly reflects "outdated" or irrelevant management practices. As discussed in Unit IV.A of this document, the majority of CCR continues to be managed in older (*i.e.,* constructed pre-1994) units that lack liners and leachate collection systems, and will in fact continue to be managed in such units for at least the near future.

Approximately six percent of the waste units associated with groundwater impacts have been constructed from 1990 onwards. Considering there is a lag time between the construction of many of the disposal units and the first detection of their groundwater impact by subsequently installed groundwater monitoring wells, the absence of damage cases associated with newer units is neither unexpected nor dispositive as to the level of risk such units pose.

Finally, a number of other factors support the conclusion that the current number of damage cases likely underestimate the current risks. First, the combined effect of a number of current state regulatory provisions is to decrease the instances in which off-site contamination will be detected (or on-site contamination will need to be remediated). For example, several states have adopted "buffer zones" where certain standards may not apply; Florida designates certain areas as a "Zone of Discharge" (ZOD), in which numerical primary and secondary drinking water standards do not apply; this exemption extends even beyond the ZOD, unless ordered specifically by the state. In addition, secondary maximum contaminant levels (SMCLs) are not applicable to existing industrial facilities discharging to groundwater in the state.[207] In other instances, states grant waivers to certain facilities that exceed health-based standards several-fold.[208] Certain states (*e.g.,* Indiana) consider surface impoundments as temporary storage facilities as long as they are dredged on a periodic basis (*e.g.,* annually). Under these states' rules, such impoundments are exempt from any solid waste regulations that would require groundwater monitoring, and from requirements for corrective action.[209] Such requirements are likely to decrease the instances in which contamination above an MCL has migrated off-site will be detected. Second, the record documents several instances where, once the contaminant plume has migrated off-site and impacted private water wells, the utility has purchased these properties, thereby rendering the off-site contamination, "on-site." At times, this practice (which is condoned by the state) has expanded the ZOD to well beyond its original boundary. Once the status of the contaminant plume changes from off-site migration, which typically requires remedial action, back to onsite containment, this can affect the kind of corrective action the state requires of the utility (or indeed whether any will be required).

### *E. Characterization of Impacts Associated With CCR Units*

#### 1. CCR Waste Unit Types Associated With Damage Cases

EPA's documented record of confirmed damage cases is dominated by wet-disposal and treatment modes: Surface impoundments, cooling ponds, and artificial wetlands constitute close to half of the total number of implicated waste units. In comparison, dry disposal modes such as landfills, sand and gravel pits, storage piles for coal ash and FGD, and certain structural fills account for about one third of the confirmed damage cases.[210] Sand and gravel pits and quarries as well as structural fills, comprise about ten percent of all the unit types that are associated with damage cases.

#### 2. Contaminants of Concern (COCs)

Because the list of constituents to be monitored in groundwater varies from permit to permit and among states, accurate estimates of the frequency of constituents associated with groundwater impacts nationwide cannot be made with confidence. Based on the available monitoring records, the most prevalent contaminant among the primary MCLs identified in damage cases is arsenic, whereas the most prevalent contaminants identified among the secondary MCLs are sulfate and boron. Similarly, disparities from one permit to another as to which constituents are monitored in NPDES discharges from CCR impoundments limit EPA's ability to identify trends associated with contaminants of concern. Based on the Agency's record of all of the confirmed damage cases, it can be only established that the most prevalent COCs with respect to Primary Water Quality Criteria (WQCs) exceedances in surface water, and/or of cleanup standards in sediments and soils are selenium and arsenic, and for Secondary WQCs or cleanup standard exceedances, are boron and iron.[211]

The high mobility of boron and sulfate explains the prevalence of these constituents in damage cases that are associated with groundwater impacts. Damage cases impacting surface water that have also a documented ecologic impact comprise the largest subset of proven damage cases (over 40 percent). The most prevalent COC here is selenium, the bioaccumulative effects of which have caused abnormal mortality rates and sublethal effects such as histopathological changes and damage to reproductive and developmental success, adversely impacting aquatic populations and communities of fish and amphibians. Such impacted communities, residing both in lentic (*e.g.,* cooling water lakes) and lotic (*e.g.,* small to medium-size streams) settings that receive regulated (*i.e.,* via permitted outfalls) and unregulated (*i.e.,* via seepage) discharge from CCR impoundments were documented and rather extensively studied in several sites (*e.g.,* in Texas, North Carolina, and South Carolina).[212] [213]

[207] Illinois uses a similar concept: Groundwater Mixing Zone; North Carolina waives any compliance requirements for constituents in exceedance of the state's groundwater standards that are confined to monitoring wells within the Compliance Boundary; and in Pennsylvania and Tennessee, state laws do not require state response to onsite exceedances of secondary MCLs.

[208] The observations cited in the following pertain to groundwater quality. Regarding surface water quality, NPDES permits in many states commonly have very limited requirements for monitoring discharge constituents, excluding all or most of the heavy metals.

[209] E.g., Duke Energy's Gibson Generating Station, Princeton, Indiana, a proven damage case.

[210] Facilities with both wet and dry disposal waste units are implicated in less than twenty percent of the cases.

[211] For a list of the key metals found in CCR wastewater and examples of the environmental concerns associated with them, see *Steam Electric Power Generating Point Source Category: Final Detailed Study Report;* EPA 821–R–09–008, October 2009: *http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Steam-Electric_Detailed-Study-Report_2009.pdf.*

[212] In validation of the findings of the Risk Assessment accompanying this rule, EPA has documented numerous damage cases where selenium in CCR wastewater discharge into surface waters triggered the issuance of fish-consumption advisories as well as selenium MCL exceedances in groundwater, suggesting that selenium concentrations in CCR wastewater constitute a human health risk.

[213] According to the draft Steam Industry's Effluent Guidelines EA, the steam electric power

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There are fewer recorded instances of surface water damage cases involving the heavy metal COCs such as antimony, beryllium, mercury, and thallium than of groundwater damage cases. It is unclear whether this genuinely reflects lower potential risks via this route of exposure. Intrinsic differences between the chemical and physical parameters of surface water and groundwater (*e.g.,* the higher redox potential and the larger flow-rate of the former) would accelerate the removal of many metals from surface water through precipitation and/or adsorption and facilitate a greater dilution. However, as noted, NPDES permits in many states commonly have very limited requirements for monitoring discharge constituents, excluding all or most of the heavy metals, so this cannot be ruled out as at least a contributing factor.[214]

3. Failure/Impact Modes

The CCR damage case record shows the following prevalent impact modes (more than one possible impact type per generating facility site is possible): Slightly over half of the recorded impact cases are associated with groundwater; about ten percent are associated with surface water, which quite frequently is also accompanied by documented ecological impacts and/or with the contamination of soils and/or river sediments; over one third are associated with both groundwater and surface water impacts; and about four percent are associated with catastrophic surface impoundment failures.

The established damage case record includes ten sites involving exceedances of primary MCLs that have impacted drinking water wells. In all of these cases, the implicated utility provided alternative potable water to well water users.[215] Three of the damage cases were listed on the National Priority List as Superfund sites,[216] and one is a Superfund Alternative (SA) site.[217] In the course of reassessing the pre-EIP 2010 damage cases and vetting EIP's alleged damage cases, the Agency rejected two other Superfund damage cases, because in addition to CCR, these site had also accepted large volume of non-CCR waste.[218]

Four major releases of CCR sludge associated with surface impoundment dike or pipe failure resulted in significant coal slurry releases,[219] causing fish kills and other ecologic damage, and in some instances damage to infrastructure. In the Clinch River spill, for instance, it was estimated that 217,000 fish were killed in a 90-mile stretch of the river in Virginia and Tennessee. The Clinch River plant coal ash had a high free lime content, which reacted with water in the settling pond to form an alkaline calcium hydroxide. As a result, during the release, pH was elevated to levels as high as 12.7. The high-toxicity shock also decimated benthic macro-invertebrate populations for a distance of over three miles below the spill site, and snails and mussels were eliminated for over 11 miles below the Clinch River power plant.

As demonstrated in the aftermath of the 2008 coal ash spill in TVA Kingston, Tennessee, large impoundment dike breach incidents result in impacts to soil and river sediments. In a study conducted few months after the spill, Emory River's downstream sediments showed high mercury concentrations similar to those detected in the coal ash (115–130 μg/kg).[220] According to this study, the ecological effects of mercury in the coal ash and sediments depend on the chemical mobility of mercury in the solids and the potential for mercury methylation in the impacted area. Previous studies have shown that sulfate addition can promote methylation in freshwater ecosystems by stimulating sulfate reducing bacteria, the primary organisms responsible for producing methylmercury in the environment. In coal-ash-containing waters, a 10- to 20-fold increase in $SO_4^{-2}$ concentrations was observed in the Emory River Cove area relative to unaffected upstream sites. Therefore, the methylation potential of mercury from this material could be high because the coal ash also provides an essential nutrient ($SO_4^{-2}$) that encourages microbial methylation. In addition, leaching of contaminants from the coal ash caused contamination of surface waters in areas of restricted water exchange and slight elevation down gradient. The accumulation of arsenic-rich fly ash in bottom sediment in the Emory River's aquatic system could cause fish poisoning via both food chains and decrease of benthic fauna that is a vital food source. Another recent study estimates that the damage to fish and other wildlife incurred by both permitted and unpermitted CCR effluent discharge at some 22 sites amounts to over $2.3 billion.[221]

sector is responsible for a significant fraction of the toxic pollutants reported to be discharged in industrial National Pollutant Discharge Elimination System (NPDES) permits.

[214] This issue is illustrated by the very limited monitoring record on mercury exceedances in surface water as compared to the extensive documentation of mercury impacts revealed in studied surface water that receive steam industry effluents. These studies have documented fish and invertebrates exposed to mercury from CCR wastewater exhibiting elevated levels of mercury in their tissues and developing sublethal effects such as reduced growth and reproductive failure. For an excellent summary of surface water ecologic and human health risks and impacts study results, see the cited Steam Electric Power study report.

[215] These proven damage cases include eight cases where the utility was directed by the state to provide an alternative water supply (NIPSCO Yard 520, IN; Constellation Energy Gambrills, MD; Don Frame Trucking, NY; Bruce Mansfield, PA; Trans Ash Landfill, TN; VEPCO Chisman Creek, VA; Stoneman, WI; and WEPCO Highway 59, WI); and two instances in which the utility provides substitute water to residents on a voluntary basis (Gibson Station, IN, and Colstrip, MT). In three additional, potential damage cases (Oak Creek, WI; Battlefield Golf Course, VA; and Joliet Station 9, IL), the utilities provide substitute water—out of abundance caution—to adjacent residential properties whose water wells were impacted by secondary MCL exceedances, and in two additional cases, the electrical utility was instructed by state regulators to provide substitute water to residential properties which either have had their drinking water wells impacted by trace amounts of thallium, within the State and the federal standards (Asheville, NC) or by exceedances of boron (Sutton, NC). Finally, in one case (Belews Creek, NC) the electric utility agreed to co-fund upgrading of potable water treatment plants in two municipalities to eliminate trihalomethanes, a carcinogenic by-product of power plant scrubber, bromide-containing river water subject to water treatment employing chlorine.

[216] OU–12, Oak Ridge, Tennessee (an NPL site between 1989 and 1997); VEPCO, Chisman Creek, Virginia (an NPL site between 1983 and 1988); and the Lemberger Landfill, Wisconsin (1986 to present).

[217] Town of Pines Groundwater Plume, Indiana (SA: 2003–Present): *http://www.epa.gov/region5/superfund/npl/sas_sites/INN000508071.htm.* The Site is not listed on the National Priority List (NPL) although it qualifies for such listing. The SA approach uses the same investigation and cleanup process and standards that are used for sites listed on the NPL, while it can potentially save the time and resources associated with listing a site on the NPL. As long as a PRP enters into an SA approach agreement with EPA, there is no need for EPA to list the site on the NPL.

[218] These are the formerly proven damage case of Salem Acres, Massachusetts (originally addressed in the 2007 *Coal Combustion Waste Damage Case Assessments* Report), and Industrial Excess Landfill, Uniontown, Ohio, an alleged damage case submitted by EIP in *In Harm's Way,* 2010.

[219] These catastrophic releases involved the release of $1.1 \times 10^9$, $2.7 \times 10^8$, $1.3 \times 10^8$, and $1 \times 10^8$ gallons of CCR slurry at the spills of the 2008 Kingston TVA, Tennessee; the 2014 Dan River, North Carolina; the 1967 Clinch River, Virginia; and the 2005 Martins Creek, Pennsylvania, respectively.) In addition, the possible ecologic impacts of two consecutive, 30 million gallons each, of CCR slurry releases (in 2007 and 2008) by the Eagle Valley power plant in Indiana have not been assessed.

[220] *Survey of the Potential Environmental and Health Impacts in the Immediate Aftermath of the Coal Ash Spill in Kingston, Tennessee.* Laura Ruhl et al., Environ. Sci. Technol. Published online on May 4, 2009. Volume *43* (16), pp 6326–6333: *http://pubs.acs.org/doi/abs/10.1021/es900714p.*

[221] A. Dennis Lemly and Joseph P. Skorupa: *Wildlife and the Coal Waste policy Debate: Proposed Rules for Coal Waste Disposal Ignore Lessons from 45 Years of Wildlife Poisoning.* Environ. Sci. Technol., 27 July, 2012.

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a. Construction Year and First Detection Year

Slightly over half of the CCR waste units identified as the source of groundwater contamination in the damage cases were commissioned in the 1970s and 1980s, two boom decades of coal-fueled power generation growth in the U.S. Whereas the majority of the CCR waste units associated with damage cases were constructed before 1990, approximately six percent of the units in the damage cases (where the commissioning date is known) became operational after 1990. For 61 units with known commissioning dates, the median lag time between commissioning and the first detection of impact to groundwater is about 20 years. However, considering the large range of lag time values (between less than one year and 50 years) the recorded median lag time most probably reflects additional variables. Possible variables include monitoring wells that were installed after many of the waste units were already well into their operating stage, and the variable hydraulic conductivity of the impoundment's substrate (including the effectiveness of its liner, if any), both of which will determine how quickly groundwater contamination is first detected. Overall, the evidence about the lag time between the commissioning of a waste unit and the first detection of the impact of its leakage implies that most likely there are prospective damage cases that have not yet been identified, challenging industry's claims that the damage cases represent the legacy of a bygone regulatory regime.

b. Liners

Of the waste units implicated in damage cases to groundwater with information on liners, over 90 percent have either no liners, some sort of ash-based liners (*e.g.,* Poz-O-Tec, an FGD/lime-conditioned liner), or only partial- or high-permeability (*e.g.,* concrete) liners. The majority of the remaining CCR waste units is either clay-lined and/or has a recognizably-failed liner. Considering that over a half of CCR waste units associated with groundwater impacts were constructed in the 1970s and 1980s, historic information on liner prevalence and composition is highly pertinent. According to the February 1988 Report to Congress on coal combustion wastes ("RTC I"), before 1975 less than 20 percent of all generating facility units managed their CCR in lined disposal units, and in generating facility units constructed since 1975, the share of lined units grew to over 40 percent.[222] However, as late as in the mid-1980s, about three-quarters of all CCR units (87 percent of surface impoundments and 39 percent of landfills) were still unlined.[223]

In the mid-1990s, the estimated prevalence of unlined landfills still ranged between 43–57 percent, and between 71–72 percent for surface impoundments.[224] According to the March 1999 Report to Congress on wastes from the combustion of fossil fuels (RTC II), the most prevalent liner type was compacted clay (about one-half of all lined landfills, and about 80-percent of all lined surface impoundments). Composite and/or synthetic liners were significantly more prevalent in landfills than in surface impoundments. Based on recent EPA data,[225] the use of liners is still more prevalent in landfills than in surface impoundments.

c. Geographic Distribution

Close to 70 percent of all the established damage cases occur in EPA Regions 5, 4, and 3 (in descending frequency, Region 5: 34 percent; Region 4: 28 percent; and Region 3: seven percent).[226] This distribution correlates well with the regional distribution of *unlined* CCR units in the mid-1980s.[227]

d. Current CCR Waste Unit Status

As of mid-2011, close to half of the combined (proven and potential) damage case CCR waste units were still active; about a quarter were inactive due to either closure of the individual disposal unit, a fuel switch (*e.g.,* from coal to gas) by the generating facility, or the decommissioning of the facility. Another quarter or so represented power generating facilities where CCR waste units (primarily impoundments) that failed to comply with state requirements had been closed and replaced by other, new disposal units, and/or the generating facilities switched from wet- to dry disposal. Since mid-2011, the percentage of inactive CCR units associated with groundwater damage cases has further increased, due to the continued drop in power demand during the economic recession, which has resulted in power station temporary removal from active service (*i.e.,* mothballing) and closures, combined with an increasing switch by many facilities to a more cost-effective fossil fuel (*i.e.,* natural gas).

*F. Conclusions*

EPA now has a significantly better understanding of CCR damage cases than when the proposed rule was issued. First, damage cases are more numerous than previously contemplated and as more monitoring well systems are installed, the number of damage cases is likely to increase. Second, the CCR damage case record corroborates the findings of the risk analysis by demonstrating the greater vulnerability of groundwater (and surface water) to wet disposal (*i.e.,* surface impoundments). Third, the damage cases show a direct correlation between the absence of liners and groundwater impacts, and illustrate that whereas in general the design of waste units—particularly surface impoundments—has improved over time, a notable portion of CCR impoundments constructed in the last two decades still lack a protective liner, thus presenting a potential threat to groundwater. Finally, a recent CCR spill incident[228] demonstrates that inactive surface impoundments that have not been properly decommissioned (*i.e.,* by breaching, dewatering, and capping or by clean-closing) continue to pose a

[222] Wastes from the Combustion of Coal by Electric Utility Power Plants (First Report to Congress), EPA/530–SW–88–002, February, 1988, pages 4–30 to 4–33: *http://www.epa.gov/osw/nonhaz/industrial/special/fossil/coal-rtc.pdf.*

[223] These statistics are based on about 42 percent of the total CCR units at that time, for which liner information was available. RTC I attributes this low percentage to the common practice of disposal in off-site units, for which liner information was not available.

[224] Based on three different partial surveys cited in the Second Report to Congress (RTC II, 1999): *Wastes from the Combustion of Fossil Fuels, Volume 2—Methods, Findings, and Recommendations* (Second Report to Congress), EPA 530–R–99–010, March 1999: *http://www.epa.gov/osw/nonhaz/industrial/special/fossil/volume_2.pdf.*

[225] EPA compiled the baseline use of bottom liners by CCR landfills and surface impoundments from the following sources: (1) Impoundment data from EPA/OSWER's 2009–2011 impoundment dam integrity site inspections; *http://www.epa.gov/waste/nonhaz/industrial/special/fossil/surveys2/index.htm*; (2) Impoundment data from ORCR's 2009 Information Collection Request (ICR) addressing power plants with impoundments; *http://www.epa.gov/waste/nonhaz/industrial/special/fossil/coalashletter.htm*; and (3) Landfill and impoundment data from EPA Office of Water's 2010 ICR addressing power plants to be affected by the Steam Electric Power Generating Effluent Guidelines: *http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm#point6.*

[226] See *http://www.epa.gov/aboutepa/#regional* for a list of states covered by each EPA Regional office.

[227] According to the Report to Congress I (1988), in the mid-1980s, the distribution of unlined CCR waste units across EPA regions was as follows: For surface impoundments: 31.7 percent (Region 4); 18.6 percent (Region 5); 6.2 percent (Region 7); and 3.5 percent (Region 3). For landfills: 11.1 percent (Region 5); 2.9 percent (Region 3); and 2.4 percent (Region 4).

[228] The Duke Energy's Dan River, North Carolina, February 2, 2014 CCR slurry spill.

significant risk to human health and the environment.

## XII. Summary of Regulatory Impact Analysis

EPA estimated the costs and benefits of the final rule. The Regulatory Impact Analysis (RIA) is available to the public in the docket for this action.

### *A. Costs of the Final Rule*

The estimated costs of the final rule are summarized in Table XII–A below. These are the incremental costs above the "baseline." *i.e.,* the current costs for managing CCR absent this regulation. The baseline takes into account existing state regulations for managing CCR now and into the future. To the extent that some states may have granted waivers or variances for certain provisions of State requirements, or in other instances may have added extra pollution control requirements above existing regulatory requirements to some specific permits issued to electric utility plants for operating CCR management units, the RIA did not take those actions into account.

EPA used the following data sources to create a model for the RIA that estimates the costs and benefits of the rule: (1) 2012 DOE EIA–923 database; (2) ORCR's 2009–2012 CCR impoundment site inspections; (3) impoundment data from ORCR's 2009 mail survey to plants with CCR impoundments; (4) landfill and impoundment data from EPA Office of Water's 2010 mail survey to power plants in support of the 2013 proposed Steam Electric Power Generating Effluent Limitation Guidelines; (5) Integrated Planning Model (IPM) v. 5.13 (for the future projection of coal consumption by electric utility plants); and (6) the 1995 Electric Power Research Institute (EPRI) Co-management Survey.

TABLE XII–A—ESTIMATED COST OF POLLUTION CONTROLS REQUIRED BY THE CCR FINAL RULE

[Millions 2013$]

| CCR pollution control | @ 3% discount rate | | @ 7% discount rate | |
|---|---|---|---|---|
| | Annualized values | Present values | Annualized values | Present values |
| 1. Groundwater monitoring | $4.79 | $151 | $2.80 | $39.9 |
| 2. Bottom liners | 491 | 15,500 | 297 | 4,230 |
| 3. Leachate collection system (landfills only) | 51.6 | 1,630 | 18.4 | 263 |
| 4. Fugitive CCR dust controls | 7.09 | 224 | 3.36 | 48.0 |
| 5. Stormwater run-on/run-off controls | 18.8 | 594 | 13.0 | 186 |
| 6. Location restrictions | 43.6 | 1,380 | 20.0 | 285 |
| 7. Closure capping | 20.1 | 630 | 12.0 | 171 |
| 8. Post-closure groundwater monitoring (30 years) | 0.08 | 2.40 | 0.04 | 0.61 |
| 9. Impoundment structural integrity requirements | 10.9 | 344 | 11.1 | 158 |
| 10. Corrective action (CCR contaminated groundwater cleanup) | 19.0 | 600 | 19.1 | 273 |
| 11. Reporting and recordkeeping | 26.3 | 831 | 27.3 | 389 |
| 12. Conversion to dry CCR handling | 29.0 | 916 | 57.3 | 818 |
| 13. Inactive impoundments (dewater and closure cap) | 12.0 | 380 | 26.7 | 381 |
| 14. Subtotal industry costs (1+...+13) | 734 | 23,200 | 508 | 7,240 |
| **State Agency Burden Costs** | | | | |
| 15. Impoundment structural integrity requirements | 0.22 | 6.88 | 0.22 | 3.16 |
| 16. Corrective action | 0.38 | 12.0 | 0.38 | 5.45 |
| 17. Reporting and recordkeeping | 0.53 | 16.6 | 0.55 | 7.78 |
| 18. Subtotal State agency burden costs (15+16+17) | 1.12 | 35.5 | 1.15 | 16.4 |
| 19. Total cost (14+18) | 735 | 23,200 | 509 | 7,260 |

### *B. Benefits of the Final Rule*

The RIA contains two categories of benefits (1) benefits that are monetized and (2) non-monetized benefits. The RIA estimates 11 categories of expected future human health and environmental benefits for the CCR rule. These include reduced future CCR impoundment structural failure releases; reduced future CCR groundwater contamination; improved air quality from reduced power plant air pollution; and surface water quality benefits. The estimated value of each of the 11 monetized benefits is presented in Table XII–B below.

TABLE XII–B—EPA ESTIMATED MONETIZED BENEFITS FOR THE CCR FINAL RULE

[Millions 2013$ over 100-year period of analysis 2016–2114]

| | 3% discount rate | | 7% discount rate | |
|---|---|---|---|---|
| | Annualized | Present value | Annualized | Present value |
| 1. Reduced CCR impoundment structural failure releases | $156 | $4,910 | $143 | $2,040 |
| 2. Reduced CCR landfill & impoundment groundwater contamination | 12.8 | 405 | 9.86 | 141 |
| 3. Induced increase in future annual CCR beneficial uses | 117 | 3,130 | 79.0 | 1,120 |
| 4. Reduced incidence of cancer from CCR exposure | <0.1 | 0.17 | <0.1 | <0.1 |
| 5. Avoided IQ losses from mercury in CCR | 0.28 | 8.80 | <0.1 | 0.35 |
| 6. Avoided IQ losses from lead in CCR | 0.186 | 5.87 | <0.1 | 0.23 |
| 7. Reduced need for specialized education (associated with 5 & 6 above) | <0.1 | <0.1 | <0.1 | <0.1 |
| 8. Non-market surface water quality benefits | 2.26 | 71.4 | 1.89 | 27.0 |

TABLE XII–B—EPA ESTIMATED MONETIZED BENEFITS FOR THE CCR FINAL RULE—Continued

[Millions 2013$ over 100-year period of analysis 2016–2114]

| | 3% discount rate | | 7% discount rate | |
|---|---|---|---|---|
| | Annualized | Present value | Annualized | Present value |
| 9. Protection of threatened & endangered species near CCR impoundments | 0.91 | 28.7 | 0.76 | 10.8 |
| 10. Improved air quality from induced changes to power plant emissions | 4.66 | 147 | 2.04 | 29.1 |
| 11. Reduced power plant groundwater withdrawals | <0.1 | <0.1 | <0.1 | <0.1 |
| 12 Total monetized benefits (1 + . . . + 11) | 294 | 8,710 | 236 | 3,360 |

In addition to the monetized benefit categories, the RIA describes 11 additional non-monetized benefit categories. Due to uncertainties and weaknesses in supporting documentation for quantifying and monetizing these benefits, the RIA presents these benefits separately from the benefits listed above, and does not include them in the quantified comparison of benefits and costs. These non-monetized benefits include:

1. Financial market benefits
2. Reduced community dread of CCR impoundment structural failure releases
3. Reduced health and property nuisance impacts from CCR fugitive dust
4. Cancer and non-cancer human health benefits from reduced CCR contamination of fish consumed by recreational anglers and subsistence fisher households in surface waters near power plants (additional to monetized avoided health effects)
5. Cancer and non-cancer human health benefits from reduced CCR exposure by other recreational users of surface waters near power plants (additional to monetized avoided health effects)
6. Avoided CCR contamination of sediments in surface waters near power plants
7. Water quality benefits from avoided CCR contamination treatment costs for use of surface waters for drinking and irrigation water supply
8. Commercial fisheries benefit in surface waters near power plants
9. Increased participation in water-based recreation near power plants
10. Avoided fish impingement and entrainment mortality from power plant water intakes (induced conversion to dry CCR handling reduces future water demand for CCR sluicing)
11. Increased property values surrounding electric utility plants (from closure capping and re-vegetation of CCR surface impoundments)

The total monetized benefits less the total costs of the rule provide the net monetized benefits of the rule. Table XII–C summarizes the total costs and benefits as well as the net benefits of the rule.

TABLE XII–C—EPA ESTIMATED INCREMENTAL COSTS & BENEFITS OF THE CCR RULE

[Millions 2013$ over 100-year period of analysis 2015–2114]

| | 3% discount rate | 7% discount rate |
|---|---|---|
| A. Annualized Values. | | |
| A1. Total Costs | $735 | $509 |
| A2 Total monetized benefits | 294 | 236 |
| A3. Net Benefits (A2–A1) | (441) | (273) |
| A4. Benefit to Cost Ratio (A3/A1) | 0.40 | 0.46 |
| B. Present Value. | | |
| B1. Total Costs | 23,200 | 7,260 |
| B2 Total monetized benefits | 8,710 | 3,360 |
| B3. Net Benefits (B2–B1) | (14,490) | (3, 900) |
| B4. Benefit to Cost Ratio (B2/B1) | 0.38 | 0.46 |

## XIII. Uniquely Associated Wastes

By way of this rule, EPA is codifying in § 261.4(b)(4) a list of low volume waste that when co-disposed with CCR are not subject to hazardous waste regulations. These wastes are also referred to as uniquely associated wastes. However, these uniquely associated wastes are subject to hazardous waste regulations when they are not co-disposed with CCR.

In a letter to EPA dated October 10, 1980 the Utility Solid Waste Activities Group (USWAG) suggested interpretive language that EPA should adopt regarding the amendments to the Solid Waste Disposal Act Amendments of 1980 which address fossil fuel combustion wastes. EPA replied to USWAG by letter dated January 13, 1981 (known as the 1981 Dietrich letter), and addressed, among other issues, other associated wastes generated in conjunction with the burning of fossil fuels.[229] EPA stated that "We believe it is appropriate, in the light of Congressional intent, to interpret the § 261.4(b)(4) exclusion to include other wastes that are generated in conjunction with the burning of fossil fuels and mixed with and co-disposed or co-treated with fly ash, bottom ash, boiler slag and flue gas emission control wastes." When amendments to the 1980 Solid Waste Disposal Act were introduced, Congressmen Bevill and Rahall stated, respectively:

> It is the sponsor's intention that this list of waste materials in the amendment be read broadly, to incorporate the waste products generated in the real world as a result of the combustion of fossil fuels. We do not believe that these terms should be narrowly read and thus impose regulatory burdens upon those who seek to assist the Nation by burning coal. EPA should recognize that these "waste streams" often include not only the

[229] See letter from Gary N. Dietrich to Paul Elmer, USWAG, available in the docket for this rule.

byproducts of the combustion of coal and other fossil fuels, but also relatively small proportions of other materials produced in conjunction with the combustion, even if not derived directly from these fuels. EPA should not regulate these waste streams because of the presence of these materials, if there is no evidence of any substantial environmental danger from these mixtures. *(126 Cong. Rec. H1102).*

In the real world, these waste materials do not include solely fly ash, bottom ash, slag, or scrubber sludge. Quite often, other materials are mixed with these large volume waste streams, with no environmentally harmful effects, and often with considerable benefit-as when, for example, boiler cleaning-acids are neutralized by being mixed with alkaline fly ash. These appear to me to be environmentally beneficial practices, which EPA should encourage. At the very least, however, the Agency should take no steps to discourage them until it has developed a full factual understanding of the situation. This amendment would assure that EPA allows all persons burning coal to avoid unnecessary regulation of the byproducts produced by that combustion, as those byproducts are currently being managed in the real world, by real people, with real sense. *(126 Cong. Rec. H1104).*

As such, EPA interpreted 40 CFR 261.4(b)(4) (the Bevill exemption) to mean that wastes produced in conjunction with the combustion of fossil fuels, which are necessarily associated with the production of energy, and which traditionally have been, and which actually are, mixed with and co-disposed or co-treated with fly ash, bottom ash, boiler slag, or flue gas emission control wastes from coal combustion are not hazardous wastes. In the Deitrich letter EPA stated that these other associated wastes include, but are not limited to the following wastes: (1) Boiler cleaning solutions; (2) boiler blowdown; (3) demineralizer regenerant; (4) pyrites; and (5) cooling tower blowdown.

In a February 1988 Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants EPA listed the following low-volume wastes commonly produced in conjunction with the burning of fossil fuels to produce electricity: (1) Boiler blowdown; (2) coal pile run-off; (3) cooling tower blowdown; (4) demineralizer regenerants and rinses; (5) metal and boiler cleaning wastes; (6) pyrites; and (7) sump effluents. Presented for each type of low-volume waste is a brief description of how the waste is generated, typical quantities produced, and the physical and chemical composition of the waste.[230] The source of this information was primarily an August 1981 USWAG/Edison Electric Institute report in response to a request for information in the 1981 Dietrich letter.

In an August 1, 1993 Regulatory Determination the Agency emphasized that co-management of low-volume wastes and large-volume wastes (fly ash, bottom ash, boiler slag, or flue gas emission control wastes from coal combustion) makes the combined waste stream a remaining waste that would be subject to a subsequent Regulatory Determination and provided the list below of management practices that result in combined waste streams that are remaining wastes.[231]

- Discharge of boiler blowdown to a large-volume waste impoundment,
- Discharge of demineralizer regenerant to a large-volume waste impoundment,
- Discharge of metal cleaning wastes to a large-volume waste impoundment,
- Discharge of boiler chemical cleaning wastes to a large-volume waste impoundment,
- Discharge of plant wastewater treatment effluent to a large-volume waste impoundment,
- Discharge of coal mill rejects to a large-volume waste impoundment,
- Disposal of oil ash in a large-volume waste landfill or impoundment,
- Disposal of plant wastewater treatment sludge in a large-volume waste landfill.

In a 1999 Report to Congress on wastes from the combustion of fossil fuels[232] EPA stated that low-volume wastes are generated as a result of supporting processes that are ancillary to, but a necessary part of, the combustion and power generation processes and provided the following list of low-volume wastes.

- Coal pile run-off
- Coal mill rejects/pyrites
- Boiler blowdown
- Cooling tower blowdown and sludge
- Water treatment sludge
- Regeneration waste streams
- Air heater and precipitator washwater
- Boiler chemical cleaning waste
- Floor and yard drains and sumps
- Laboratory wastes
- Wastewater treatment sludge

The concept of uniquely associated wastes with respect to CCR was first introduced in the May 22, 2000 Regulatory Determination. Prior to this, these wastes were referred to as other wastes, remaining wastes, or low-volume wastes, that are generated in conjunction with the burning of fossil fuels and mixed with and co-disposed or co-treated with fly ash, bottom ash, boiler slag and flue gas emission control wastes. For the May 22, 2000 Regulatory Determination, the Agency proposed the uniquely associated wastes concept with the intent of being consistent with other wastes covered under the Bevill Amendment (a.k.a., the Bevill exemption), such as mining and mineral processing wastes that the Agency refers to as uniquely associated wastes, and under the Bentsen Amendment for oil and gas exploration and production wastes which are referred to as associated wastes. The Agency recognized that determining whether a particular waste is uniquely associated with fossil fuel combustion involves an evaluation of the specific facts of each case. In the Agency's view, the following qualitative criteria should be used to make such determinations on a case-by-case basis:

(1) Wastes from ancillary operations are not "uniquely associated" because they are not properly viewed as being "from" fossil fuel combustion.

(2) In evaluating a waste from non-ancillary operations, one must consider the extent to which the waste originates or derives from the fossil fuels, the combustion process, or combustion residuals, and the extent to which these operations impart chemical characteristics to the waste.

EPA proposed the following list of wastes that the Agency considered to be uniquely associated wastes (*i.e.,* uniquely associated with the combustion of coal for the generation of electricity at electric utilizes and independent power producers and, therefore, covered by the Bevill exemption).

- Coal Pile Run-Off
- Coal Mill Rejects and Waste Coal
- Air Heater and Precipitator Washes
- Floor and Yard Drains and Sumps
- Wastewater Treatment Sludges
- Boiler Fireside Chemical Cleaning Wastes

EPA also proposed the following list of wastes that would not be considered uniquely associated wastes.

- Boiler Blowdown
- Cooling Tower Blowdown and Sludges
- Intake or Makeup Water Treatment and Regeneration Wastes
- Boiler Waterside Cleaning Wastes
- Laboratory Wastes
- General Construction and Demolition Debris

[230] See *http://www.epa.gov/osw/nonhaz/industrial/special/fossil/coal-rtc.pdf,* pages 3–41 to 3–62. This report addressed wastes generated from the combustion of coal by electric utility power plants, and did not address comanaged utility coal combustion wastes, other fossil fuel combustion wastes, and wastes from non-utility boilers.

[231] *http://www.epa.gov/osw/nonhaz/industrial/special/mineral/080993.pdf.*

[232] *http://www.epa.gov/osw/nonhaz/industrial/special/fossil/volume_2.pdf.*

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- General Maintenance Wastes

EPA requested comments on these proposed lists and received several comments from states, industry, and the environmental community. Industry opposed the "uniquely associated" waste framework, and favors retaining the 1981"Dietrich Policy."

Many commenters argued that the Dietrich policy has provided clear guidance on the scope of the Bevill exemption for the past 20 years, and that appropriate waste management practices have been implemented for these wastes. The Dietrich Policy has proven itself effective in furthering congressional intent to recognize certain historic co-management practices provided they are not environmentally harmful. The Association of State and Territorial Solid Waste Management Officials recommended that EPA contact States that have management programs for fossil fuel combustion wastes to determine how to best manage the waste that are uniquely associated or not uniquely associated with fossil fuel combustion wastes. The Hoosier Environmental Council opposed exempting coal wastes and stated that "coal mill rejects and coal pile run-off would not be uniquely associated wastes . . . because neither of these wastes is derived from coal combustion."

EPA acknowledges that the Deitrich letter has been longstanding policy with regard to CCR uniquely associated wastes and that the Agency has not sought input from States on the issue. Moreover, as evident from the Congressional Record, the Congressional intent was to "include not only the byproducts of the combustion of coal and other fossil fuels, but also relatively small proportions of other materials produced in conjunction with the combustion, even if not derived directly from these fuels." These other materials would include many of those listed in the Dietrich letter as well as many of those listed in the May 2000 Regulatory determination.

After considering the 1981 Dietrich letter, a copy of which is included in the docket for this rule, the proposed guidance in the May 2000 Regulatory Determination, comments received on the May 2000 Regulatory Determination and the July 2010 proposed rule, EPA has concluded that the 1981 Dietrich letter accurately reflects the intent of Congress when they exempted CCR from hazardous waste regulations. EPA also believes that many of the wastes listed as uniquely associated wastes in the May 22, 2000 Regulatory Determination are also consistent with the Congressional intent. Therefore, the Agency is finalizing the following list of uniquely associated wastes that includes materials from both the Dietrich letter and the May 2000 Regulatory Determination.

- Coal pile run-off
- Boiler cleaning solutions
- Boiler blowdown
- Process water treatment and demineralizer regeneration wastes
- Cooling tower blowdown
- Air heater and precipitator washes
- Effluents from floor and yard drains and sumps, and
- Wastewater treatment sludges

This list is being codified in 40 CFR 261.4(b): Solid wastes which are not hazardous wastes.

## XIV. Statutory and Executive Order Reviews

### *A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review*

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. The total annual cost of this final rule is estimated to be $509 million a year using a 7% discount rate. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, EPA prepared an analysis of the potential costs and benefits associated with this action. The Regulatory Impact Analysis (RIA) estimated the costs and benefits for this action. The RIA estimated 12 regulatory costs: (1) Groundwater monitoring; (2) bottom liner installation; (3) leachate collection system installation and management; (4) fugitive dust controls; (5) rain and surface water run-on/run-off controls; (6) disposal unit location restrictions (including water tables, floodplains, wetlands, fault areas, seismic zones, and karst terrain); (7) closure capping to cover units; (8) post-closure groundwater monitoring requirements; and (9) impoundment structural integrity requirements; (10) corrective actions (CCR contaminated groundwater cleanup); (11) paperwork reporting/recordkeeping; and (12) impoundment closures and conversion to dry handling. Using a 7% discount rate, the annualized costs are estimated at $509 million, and using a 3% discount rate, annualized costs are estimated to be $735 million. Using a 7% discount rate, the total present value costs are estimated at $7.3 billion, and using a 3% discount rate the present value of estimated costs is $23.2 billion.

The RIA estimated 11 monetized benefits: (1) CCR impoundment release prevention; (2) CCR landfill & impoundment groundwater contamination prevention; (3) induced increase in CCR beneficial uses (*e.g.*, concrete, wallboard); (4) reduced incidence of cancer from CCR exposure; (5) avoided IQ losses from mercury; (6) avoided IQ losses from lead; (7) reduced need for specialized education; (8) non-market surface water quality benefits; (9) protection of threatened & endangered species near CCR impoundments; (10) improved air quality from induced changes to power plant emissions and (11) reduced power plant groundwater withdrawals. The annualized monetized benefits are estimated at $294 million (@ 3% discount rate) and $236 million (@ 7% discount rate). The total present value monetized benefits are estimated at $8.7 billion (@ 3% discount rate) and $3.4 billion (@ 7% discount rate).

### *B. Paperwork Reduction Act (PRA)*

The information collection activities in this rule will be submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 1189.25, OMB control number 2050–0053. You can find a copy of the ICR in the docket for this rule, which will be available in the docket once the ICR has been submitted to OMB for review, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

These regulations, promulgated under subtitle D of RCRA, constitute national minimum criteria with which facilities must comply without oversight or intervention by a federal or state authority. To address concerns about the absence of regulatory oversight under a subtitle D regulation, EPA has developed a combination of mechanisms, including recordkeeping, notification, and maintaining a publicly accessible Internet site. The increased transparency resulting from these requirements will minimize the potential for owners or operators to abuse the self-implementing system established in this rule. In addition, these requirements provide interested parties the information necessary to

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determine whether the owner or operator is operating in compliance with the requirements of the rule and thus will facilitate enforcement by States and private citizens. EPA has consolidated the recordkeeping, notification, and Internet posting requirements into a single section of the regulations in an effort to make these requirements easier to follow. It is important to note that EPA will not be collecting any information under this rule—instead, facilities must keep records, notify the state, and post information on a publicly available Web site. EPA has taken steps to minimize the burden to the regulated community while at the same time achieving the transparency needed to ensure proper implementation of this rule. In addition to the burden to owner and operators of CCR landfills, in an effort to ease implementation, EPA has reporting and recordkeeping requirements for certain beneficial uses and states. For beneficial use that meets the fourth criteria, the user must maintain records and provide documentation upon request. For states, states are encouraged to voluntarily adopt at least the federal minimum criteria through the revision of SWMPs. In addition, EPA estimated the burden on state government agencies associated with the receipt of various notification requirements in the rule.

The respondents/affected entities are the owners/operators of electric utilities and independent power producers that fall within the NAICS code 221112. Specifically, these regulations apply to owners and operators of new and existing landfills and new and existing surface impoundments, including lateral expansions that of all landfills and surface impoundments that dispose or otherwise engage in solid waste management of CCR generated from the combustion of coal at electric utilities. The rule also applies to CCR units located off-site of the electric utilities' or independent power producers' facilities that receive CCR for disposal. The rule applies to certain inactive CCR surface impoundments at active electric utilities' or independent power producers' facilities, if the CCR unit still contains CCR and liquids. Finally, the rule applies to certain beneficial users of CCR. The rule may also impact States that choose to revise their SWMPs.

Respondents are obligated to keep records, make the required notifications, and maintain the publicly available Internet site. These requirements are part of the minimum federal criteria under 40 CFR part 257 and promulgated under the authority of sections 1006(b), 1008(a), 2002(a), 3001, 4004, and 4005(a) of the Solid Waste Disposal Act of 1970, as amended by the Resource Conservation and Recovery Act of 1976 (RCRA), as amended by the Hazardous and Solid Waste Amendments of 1984 (HAS), 42 U.S.C. 6906(b), 6907(a), 6912(a), 6944, and 6945(a).

*Respondents/affected entities:* EPA estimates the total number of respondents to be 486. This number represents the estimated number of coal-fired electric utility plants that will be affected by the rule.

*Respondent's obligation to respond:* The recordkeeping, notification, and posting are part of the minimum national criteria being promulgated under Sections 1008, 4004, and 4005(a) of RCRA.

*Estimated number of respondents:* 486.

*Frequency of response:* The frequency of response varies.

*Total estimated burden:* EPA estimates the total annual burden to respondents to be approximately 358,957 hours with a three year total estimated burden of 1,076,871 hours. Burden is defined at 5 CFR 1320.3(b).

*Total estimated cost:* The total estimated annual cost is approximately $64,007,121; this is composed of approximately $22,894,608 in annualized labor costs and $41,112,513 in annualized capital or operation and maintenance costs. The three year total estimated costs are $192,021,364 composed of $68,683,824 in labor costs and $123,337,540 in operations and maintenance.

In addition, developing a state SWMP (see Unit IX of this preamble) is not a requirement under this rule, however, EPA is encouraging states to develop these plans and has developed a burden estimate associated with this activity. The estimate for this one-time activity has been annualized over the three-year period covered by the ICR. The total estimated annual burden (for the 47 states and Puerto Rico where CCR are generated) is approximately 10,880 hours, and approximately $429,414 in annualized labor costs; this estimate assumes no annualized capital or operations and maintenance costs.

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 the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

*C. Regulatory Flexibility Act*

The Regulatory Flexibility Act (RFA) 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 (SISNOSE). Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as: (1) A small business, based on the U.S. Small Business size standard for NAICS code 221112 (fossil fuel electric utility plants), with fewer than 750 employees; (2) a small government jurisdiction, based on the RFA/SBREFA's definition (5 U.S. Code section 601(5)), is the government of a city, county, town, township, village, school district, or special district with population under 50,000; (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities.

The small entities directly regulated by this final rule consist of one small county, 31 small cities, 32 small companies, and 13 small cooperative owner entities that own at least one coal-burning power plant. There are 91 coal-burning power plants that are owned by the 77 small owner entities. Those plants fall into the following categories: One small county plant, 31 small city plants, 42 plants owned by small companies, and 17 small cooperative plants.

The RIA estimated CCR compliance costs as a percentage of revenues for each entity and found that for almost all small entities affected by the rule the estimated annualized costs were less than 1% of revenues.

Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities.

*D. Unfunded Mandates Reform Act (UMRA)*

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 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. This rule contains a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, EPA has prepared under section 202 of the UMRA a written statement which is summarized below.

The RIA estimates the rule may affect 414 coal-fired electric utility plants, and may have a nationwide average annualized cost of approximately $509 million per year (at a 7% discount rate). Of this amount, average annualized costs to State/local governments total $36 million, and the average annualized cost to the private sector totals approximately $436 million per year (the remainder of the total costs are the costs associated with compliance at federally-owned electric utility plants.)

Consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA initiated pre-proposal consultations with governmental entities affected by this rule. In developing the regulatory options for the CCR rule, EPA consulted with small governments according to EPA's UMRA interim small government consultation plan developed pursuant to section 203 of UMRA. EPA's interim plan provides for two types of possible small government input: Technical input and administrative input. According to this plan, and consistent with section 204 of UMRA, early in EPA's 2009 process for developing the CCR rule, EPA implemented a small government consultation process consisting of two consultation components: (1) A series of meetings in 2009 for purposes of acquiring technical input from State government officials, and (2) letters to 10 organizations representing elected State and local government officials to inform and seek input for the rule's development, as well as to invite them to a meeting held September 16, 2009 in Washington DC to provide input on the rule. Following are the meetings held with state officials in 2009: (1) February 27 with the Association of State and Territorial Solid Waste Management Officials (ASTSWMO) Coal Ash Workgroup (Washington DC), (2) March 22–24 with the Environmental Council of States (ECOS) Spring Meeting (Alexandria VA), (3) April 15–16 with the ASTSWMO Mid-Year Meeting (Columbus OH), (4) May 12–13 with the EPA Region IV State Directors Meeting (Atlanta, GA), (5) June 17–18 with the ASTSWMO Solid Waste Managers Conference (New Orleans, LA), (6) July 21–23 with the ASTSWMO Board of Directors Meeting (Seattle, WA), and (7) August 12 with the ASTSWMO Hazardous Waste Subcommittee Meeting (Washington DC). ASTSWMO is an organization with a mission to work closely with the EPA to ensure that its state government members are aware of the most current developments related to state waste management programs. ECOS is a national non-profit, non-partisan association of state and territorial environmental agency leaders. As a result of these meetings EPA received letters in mid-2009 from 22 state governments as well as a letter from ASTSWMO expressing their stance on CCR regulatory options.

On August 24, 2009 letters were mailed to the following 10 organizations, which include representation from small government elected officials, to inform and seek input for the rule development, as well as to invite them to a meeting held September 16, 2009 in Washington DC: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) County Executives of America, (7) National Association of Counties, (8) International City/County Management Association, (9) National Association of Towns and Townships, and (10) Environmental Council of the States. These 10 organizations representing State and local government officials are identified in EPA's November 2008 Federalism guidance as the "Big 10" organizations appropriate to contact for purpose of consultation with small government elected officials.

Consistent with section 205, EPA identified and considered a reasonable number of regulatory alternatives in the June 2010 proposed rule, and is adopting the least-costly approach (*i.e.* a modified version of the "D Prime" least costly approach presented in the 2010 proposed CCR rule).

This rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. The threshold amount established for determining whether regulatory requirements could significantly affect small governments is $100 million annually. The RIA estimates a $1.2 million annual cost for state/local government implementation of the rule and $36 million in annual direct compliance costs on 57 state or local governments. These estimates are well below the $100 million annual threshold established under UMRA. However this rule does have over a $100 million dollar impact on industry. EPA selected one of the lower industry cost options for the final rule by selecting a RCRA subtitle D rule instead of a RCRA subtitle C rule.

*E. Executive Order 13132—Federalism*

The EPA has concluded that this action may have federalism implications because it imposes substantial direct compliance costs on state or local governments, and the Federal government will not provide the funds necessary to pay those costs. Based on the estimates in EPA's RIA for this action, the final rule, if promulgated, may impose a $1.2 million annual cost for state/local government implementation of the rule and $36 million in annual direct compliance costs on 57 state or local governments. This amount exceeds the $25 million per year "substantial compliance cost" threshold defined in section 1.2(A) (1) of EPA's November 2008 "Guidance on Executive Order 13132: Federalism." There are 57 State and local governments which own 68 coal-burning power plants or 16% of the 414 electric utility plants expected to be affected by this rule. These 57 local governments consist of 7 state governments, 31 small municipality governments, 18 non-small municipal governments and 1 (small) county government owner.

The EPA provides the following federalism summary impact statement. The EPA consulted with state and local officials early in the process of developing the proposed action to permit them to have meaningful and timely input into its development. In developing the regulatory options described in this final action, EPA consulted with 10 national organizations representing state and local elected officials to ensure meaningful and timely input by state/local governments, consisting of two consultation components. This consultation is described and summarized in the UMRA section above.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and state and local governments, EPA specifically solicited comment on the proposed action from state and local officials. EPA received comments from over two hundred (200) entities representing state and local governments. The comments submitted primarily addressed the issue presented in the proposal of which approach to regulating CCR was appropriate—a regulation under subtitle C or under subtitle D of RCRA. The state and local government commenters overwhelming

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voiced their opposition to a regulation under subtitle C, citing impacts to state programs if EPA were to bring such a large number of facilities and a large volume of waste into the subtitle C universe. State governments were very concerned with the resources which would be required to issue subtitle C permits to these facilities and to develop and obtain EPA approval of revisions to their authorized RCRA subtitle C programs. They also expressed concerns about the limits in the existing hazardous waste disposal capacity in the United States to absorb such a large volume of new wastes, also citing the financial burden and potential liability problems for cities and towns that operate landfills or use landfills to dispose of waste that might include coal ash.

In addition, states and local governments expressed concern that a subtitle C rule would have a negative effect on beneficial use of CCR and on state beneficial use programs. State and local governments fully supported continued beneficial use of CCR and continuation of the Bevill exemption for CCR beneficial use. They requested that EPA establish standards to ensure that beneficial uses are protective of human health and the environment and ensure consistency in management of these materials throughout the country. They specifically cited the use of CCR in cement and concrete applications, highway construction projects and wallboard manufacture (among other uses) and the impacts to municipalities through increased costs and potential job loss if CCR is classified as a hazardous waste. They also noted an expectation that utility rates would rise as a result of CCR being disposed of in landfills rather than being used for beneficial purposes, due to limited availability of commercial hazardous waste disposal facilities and costs of transporting high volumes of CCR to these facilities. State Departments of Transportation expressed particular concern that a subtitle C rule would negatively affect the use of CCR in road bed. Commenters further supported continued beneficial use of CCR to reduce the need for mining for substitute products in cement and concrete. Finally, should CCR be classified as a hazardous waste, they indicated the need for EPA to clarify that products made using CCR are new products and not considered hazardous wastes, and may be treated in the same manner as similar products made without CCR.

Since EPA is promulgating this regulation under subtitle D, the concerns over the potential effect of a subtitle C regulation on beneficial use are moot. Moreover in this final rule, EPA has established a definition for beneficial use which we believe makes clear the distinction between beneficial use and disposal. This is fully discussed in Unit VI of this document.

While States supported a rule under subtitle D, they also voiced concern about the need for flexibility to address site-specific situations, as would be available under a state permitting program, and concern about potential inconsistencies between the new federal requirements and existing State programs. States suggested that regulation under subtitle D should embrace the existing state permitting programs—allowing state permitting programs as the foundation for regulating CCR disposal—and requested financial incentives to implement federal criteria through state solid waste programs. They also emphasized the need to allow time for states to make necessary changes in existing state rules and statutes to incorporate federal criteria. A few expressed the desire that financial assurance for closure, post closure care, and corrective action should be included in the final rule as a mechanism to ensure that funds will be provided by owners and operators to carry out these activities.

As fully explained earlier in this document, EPA is promulgating this rule under subtitle D of RCRA. As such, these regulations constitute the minimum federal requirements which apply to CCR units. States are not required to adopt these regulations or to revise their state programs to incorporate the new federal requirements. As fully discussed in Unit V of this document, "Development of the RCRA Subtitle D Regulatory Approach," sections 1008(a), 4004, and 4005(a) of RCRA (*i.e.,* subtitle D) does not provide EPA with the ability to require states to issue permits, to approve state programs to operate in lieu of the federal program, or to enforce any of the requirements addressing the disposal of CCR. Consequently EPA designed the final rule to ensure protection of public health and the environment within these limitations. In addition, to help address potential implementation challenges that this statutory and resulting regulatory structure impose, as fully set out in Section IX of this document, EPA is encouraging states to revise their Solid Waste Management Plans and to submit these to EPA for approval.

A complete list of the comments from state and local governments has been provided to the Office of Management and Budget and has been placed in the docket for this rulemaking. In addition, the detailed response to comments from these entities is contained in EPA's response to comments document on this rulemaking.

As required by section 8(a) of Executive Order 13132, EPA included a certification from its Federalism Official stating that EPA had met the Executive Order's requirements in a meaningful and timely manner when it sent the draft of this final action to OMB for review pursuant to Executive Order 12866. A copy of this certification is included in the public version of the official record for this final action.

*F. Executive Order 13175—Consultation and Coordination With Indian Tribal Governments*

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

EPA has concluded that this action may have tribal implications. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. As identified in EPA's Regulatory Impact Analysis for this action, there are no known tribal owner entities of the coal-fired electric utility plants affected by this action. Although there are three of the 414 coal-fired electric utility plants (in operation as of 2012) which are located on tribal lands, they are not owned by tribal governments. These are: (1) Navajo Generating Station in Coconino County, owned by the Arizona Salt River Project; (2) Bonanza Power Plant in Uintah County, Utah, owned by the Deseret Generation and Transmission Cooperative; and (3) Four Corners Power Plant in San Juan County, New Mexico owned by the Arizona Public Service Company. The Navajo Generating Station and the Four Corners Power Plant are on lands belonging to the Navajo Nation, while the Bonanza Power Plant is located on the Uintah and Ouray Reservation of the Ute Indian Tribe.

EPA consulted with tribal officials early in the process of developing this regulation to permit them to have meaningful and timely input into its development.

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*G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks*

This action is subject to E.O. 13045 (62 FR 19885, April 23, 1997) because it is an economically significant regulatory action as defined by E.O. 12866, and EPA believes that the environmental health or safety risks addressed by this action may have a disproportionate effect on children. Accordingly, we have evaluated the environmental health or safety effects of Coal Combustion Residual constituents of potential concern on children. The results of this evaluation are contained in the *Human and Ecological Risk Assessment of Coal Combustion Wastes* available in the docket for this action.

As ordered by E.O. 13045 Section 1–101(a), EPA identified and assessed environmental health risks and safety risks that may disproportionately affect children in the revised risk assessment. Pursuant to U.S. EPA's Guidance on Selecting Age Groups for Monitoring and Assessing Childhood Exposures to Environmental Contaminants, children are divided into seven distinct age cohorts: 1 to <2 yr, 2 to <3 yr, 3 to <6 yr 6 to <11 yr, 11 to <16 yr, 16 to <21 yr, and infants (<1 yr). Using exposure factors for each of these cohorts, EPA calculated cancer and non-cancer risk results in both the screening and probabilistic phases of the assessment. In general, risks to infants tended to be higher than other childhood cohorts, and also higher than risks to adults. However, for drinking water cancer risks, the longer exposures for adults led to the highest risks. Screening risks exceeded EPA's human health criteria for children exposed to contaminated air, soil, and food resulting from fugitive dust emissions and run-off. Similarly, 90th percentile child cancer and non-cancer risks exceeded the human health criteria for the groundwater to drinking water pathway under the full probabilistic analysis (Table 5–17 in the *Human and Ecological Risk Assessment of Coal Combustion Wastes*). As ordered by E.O. 13045 Section 101(b) EPA has ensured that the standard addresses disproportionate risks to children that result from environmental health risks. The results of the screening assessment finds that risks fell below the criteria when wetting and run-on/runoff controls required by the rule are considered. Under the full probabilistic analysis, composite liners required by the rule for new waste management units showed the ability to reduce the 90th percentile child cancer and non-cancer risks for the groundwater to drinking water pathway to well below EPA's criteria. Additionally, the groundwater monitoring and corrective action required by the rule will reduce risks from current waste management units. Thus, EPA believes that this rule will be protective of children's health.

In general, because the pollution control requirements under the CCR rule will reduce health and environmental exposure risks at all coal-fired electric utility plants, the CCR rule is not expected to create additional or new risks to children.

*H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use*

Executive Order 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 (OMB), for actions identified as "significant energy actions." This action, which is a significant regulatory action under Executive Order 12866, is not likely to have a significant adverse effect on the supply, distribution, or use of energy based on the results of the electricity price impact estimates of the Regulatory Impact Analysis (RIA) for this action. We have prepared a Statement of Energy Effects for this action.

According to Executive Order 13211, the statement should address (i) any adverse effects on energy supply, distribution, or use, (including a shortfall in supply, price increases, and increased use of foreign supplies) should the proposal be implemented, and (ii) reasonable alternatives to the action with adverse energy effects and the expected effects of such alternatives on energy supply, distribution, and use.

The potential impact of the final CCR rule on electricity prices is analyzed relative to the "in excess of one percent" threshold which is one of nine alternative numerical indicators established by OMB for defining "significant adverse effect" under Executive Order 13211.[233] The integrated planning model (IPM) estimates potential increases in wholesale electricity prices for 22 National Energy Modeling System (NEMS) regions. In addition, the analysis focuses on potential changes in electricity prices in 2020, 2025, and 2030. The analysis focuses on these relatively early year in the analytic time horizon examined in the RIA to minimize uncertainty in the estimated electricity price impacts. In addition, under the provisions of the rule, the year 2018 is when impoundments begin to undergo closure or wet/dry conversion if they are found to be leaking. Therefore, 2020, 2025, and 2030 represent high-cost year relative to other years in the analytic time horizon, and the analysis presented here will likely yield conservative estimates of the rule's impact on electricity prices.

Using IPM, the weighted average nationwide potential increase in the wholesale price of electricity is not expected to exceed one percent (between .18% and 0.19% in the years 2020 through 2030). However, for one of the 22 NEMS regions (AZNM), the RIA projects a potential price increase above one percent (between 0.78% and 1.05% in the years 2020 through 2030).

Finally, any retail electricity price increases, if they occur, would have the effect of offsetting a portion of the compliance costs to electric utilities estimated in the RIA, as the utilities would be recovering costs through price increases to customers. Therefore, these impacts are not additive to total rule costs, but would instead offset costs to utilities estimated in the RIA.

Only one region may slightly exceed a one percent electricity price increase, which the RIA estimated without considering the potential reduction in such impact with the compliance deadline flexibility of this action for CCR surface impoundments. Thus all regions are likely to experience less than one percent electricity price impacts of this action. Therefore, this statement does not address reasonable alternatives to the action because EPA does not expect this action to have adverse energy effects as defined by OMB.

*I. National Technology Transfer and Advancement Act*

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do 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. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use

[233] OMB defines nine alternative numerical indicators of "significant adverse effect" on energy supply, distribution, or use in Section 4 of its "Memorandum for Heads of Executive Departments and Agencies, and Independent Regulatory Agencies," M–01–27, July 13, 2001.

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available and applicable voluntary consensus standards.

This rulemaking involves technical standards. EPA has decided to use the following technical standards in this rule: (1) RCRA Subpart D, Section 257.70 liner design criteria for new CCR landfills and any lateral expansion of a CCR landfill includes voluntary consensus standards developed by ASTM International and EPA test methods such as SW–846, (2) Section 257.71 liner design criteria for existing CCR surface impoundments include voluntary consensus standards developed by ASTM International and EPA test methods such as SW–846, (3) Section 257.72 liner design criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment include voluntary consensus standards developed by ASTM International and EPA test methods such as SW–846, and (4) Section 257.73 structural stability standards for new and existing surface impoundments use the ASTM D 698 and 1557 standards for embankment compaction.

*J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations*

Executive Order (E.O.) 12898 (59 FR 7629, Feb. 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

EPA's risk assessment for this action did not separately evaluate either minority or low income populations. However, to evaluate the demographic characteristics of communities that may be affected by the CCR rule, the RIA compares the demographic characteristics of populations surrounding coal-fired electric utility plants with broader population data for two geographic areas: (1) One-mile radius from CCR management units (*i.e.,* landfills and impoundments) likely to be affected by groundwater releases from both landfills and impoundments; and (2) watershed catchment areas downstream of surface impoundments that receive surface water run-off and releases from CCR impoundments and are at risk of being contaminated from CCR impoundment discharges (*e.g.,* unintentional overflows, structural failures, and intentional periodic discharges).

For the population as a whole 24.8% belong to a minority group and 11.3% falls below the Federal Poverty Level. For the population living within one mile of plants with surface impoundments 16.1% belong to a minority group and 13.2% live below the Federal Poverty Level. These minority and low-income populations are not disproportionately high compared to the general population. The percentage of minority residents of the entire population living within the catchment areas downstream of surface impoundments is disproportionately high relative to the general population, *i.e.,* 28.7%, versus 24.8% for the national population. Also, the percentage of the population within the catchment areas of surface impoundments that is below the Federal Poverty Level is disproportionately high compared with the general population, *i.e.,* 18.6% versus 11.3% nationally.

Comparing the population percentages of minority and low income residents within one mile of landfills to those percentages in the general population, EPA found that minority and low-income residents make up a smaller percentage of the populations near landfills than they do in the general population, *i.e.,* minorities comprised 16.6% of the population near landfills versus 24.8% nationwide and low-income residents comprised 8.6% of the population near landfills versus 11.3% nationwide. In summary, although populations within the catchment areas of plants with surface impoundments appear to have disproportionately high percentages of minority and low-income residents relative to the nationwide average, populations surrounding plants with landfills do not. Because landfills are less likely than impoundments to experience surface water run-off and releases, catchment areas were not considered for landfills.

Because the CCR rule is risk-reducing, with reductions in risk occurring largely within the surface water catchment zones around, and groundwater beneath, coal-fired electric utility plants, the rule will not result in new disproportionate risks to minority or low-income populations.

*K. Congressional Review Act*

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A Major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective 180 days after its publication in the **Federal Register**.

**List of Subjects**

*40 CFR Part 257*

Environmental protection, Beneficial use, Coal combustion products, Coal combustion residuals, Coal combustion waste, Disposal, Hazardous waste, Landfill, Surface impoundment.

*40 CFR Part 261*

Environmental protection, Hazardous waste, Recycling, Reporting and recordkeeping requirements.

Dated: December 19, 2014.

**Gina McCarthy,**

*Administrator.*

For the reasons set out in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as follows:

## PART 257—CRITERIA FOR CLASSIFICATION OF SOLID WASTE DISPOSAL FACILITIES AND PRACTICES

■ 1. The authority citation for part 257 continues to read as follows:

**Authority:** 42 U.S.C. 6907(a)(3), 6912(a)(1), 6944(a); 33 U.S.C. 1345(d) and (e).

■ 2. Section 257.1 is amended by:

■ a. Adding a sentence at the end of paragraph (a) introductory text;

■ b. Revising paragraphs (a)(1) and (2); and

■ c. Adding paragraph (c)(12).

The revisions and additions read as follows:

**§ 257.1 Scope and purpose.**

(a) * * * Unless otherwise provided, the criteria in §§ 257.50 through 257.107 are adopted for determining which CCR landfills and CCR surface impoundments pose a reasonable probability of adverse effects on health or the environment under sections 1008(a)(3) and 4004(a) of the Act.

(1) Facilities failing to satisfy any of the criteria in §§ 257.1 through 257.4 or §§ 257.5 through 257.30 or §§ 257.50 through 257.107 are considered open dumps, which are prohibited under section 4005 of the Act.

(2) Practices failing to satisfy any of the criteria in §§ 257.1 through 257.4 or §§ 257.5 through 257.30 or §§ 257.50 through 257.107 constitute open dumping, which is prohibited under section 4005 of the Act.

* * * * *

(c) * * *

(12) Except as otherwise specifically provided in subpart D of this part, the criteria in subpart A of this part do not apply to CCR landfills, CCR surface impoundments, and lateral expansions of CCR units, as those terms are defined in subpart D of this part. Such units are instead subject to subpart D of this part.

■ 3. Section 257.2 is amended by adding in alphabetical order definitions for "CCR landfill" and "CCR surface impoundment" to read as follows:

**§ 257.2 Definitions.**

* * * * *

*CCR landfill* means an area of land or an excavation that receives CCR and which is not a surface impoundment, an underground injection well, a salt dome formation, a salt bed formation, an underground or surface coal mine, or a cave. For purposes of this subpart, a CCR landfill also includes sand and gravel pits and quarries that receive CCR, CCR piles, and any practice that does not meet the definition of a beneficial use of CCR.

*CCR surface impoundment* means a natural topographic depression, man-made excavation, or diked area, which is designed to hold an accumulation of CCR and liquids, and the unit treats, stores, or disposes of CCR.

* * * * *

■ 4. Part 257 is amended by:

■ a. Adding and reserving subpart C; and

■ b. Adding subpart D.

The additions read as follows:

## Subpart C—[Reserved]

## Subpart D—Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments

**General Provisions**

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257.50 Scope and purpose.
257.51 Effective date of this subpart.
257.52 Applicability of other regulations.
257.53 Definitions.

**Location Restrictions**

257.60 Placement above the uppermost aquifer.
257.61 Wetlands.
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**Design Criteria**

257.70 Design criteria for new CCR landfills and any lateral expansion of a CCR landfill.
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257.72 Design criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment.
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257.74 Structural integrity criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment.

**Operating Criteria**

257.80 Air criteria.
257.81 Run-on and run-off controls for CCR landfills.
257.82 Hydrologic and hydraulic capacity requirements for CCR surface impoundments.
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**Groundwater Monitoring and Corrective Action**

257.90 Applicability.
257.91 Groundwater monitoring systems.
257.92 [Reserved]
257.93 Groundwater sampling and analysis requirements.
257.94 Detection monitoring program.
257.95 Assessment monitoring program.
257.96 Assessment of corrective measures.
257.97 Selection of remedy.
257.98 Implementation of the corrective action program.

**Closure and Post-Closure Care**

257.100 Inactive CCR surface impoundments.
257.101 Closure or retrofit of CCR units.
257.102 Criteria for conducting the closure or retrofit of CCR units.
257.103 Alternative closure requirements.
257.104 Post-closure care requirements.

**Recordkeeping, Notification, and Posting of Information to the Internet**

257.105 Recordkeeping requirements.
257.106 Notification requirements.
257.107 Publicly accessible internet site requirements.

## Subpart D—Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments

**§ 257.50 Scope and purpose.**

(a) This subpart establishes minimum national criteria for purposes of determining which solid waste disposal facilities and solid waste management practices do not pose a reasonable probability of adverse effects on health or the environment under sections 1008(a)(3) and 4004(a) of the Resource Conservation and Recovery Act.

(b) This subpart applies to owners and operators of new and existing landfills and surface impoundments, including any lateral expansions of such units that dispose or otherwise engage in solid waste management of CCR generated from the combustion of coal at electric utilities and independent power producers. Unless otherwise provided in this subpart, these requirements also apply to disposal units located off-site of the electric utility or independent power producer. This subpart also applies to any practice that does not meet the definition of a beneficial use of CCR.

(c) This subpart also applies to inactive CCR surface impoundments at active electric utilities or independent power producers, regardless of the fuel currently used at the facility to produce electricity.

(d) This subpart does not apply to CCR landfills that have ceased receiving CCR prior to October 19, 2015.

(e) This subpart does not apply to electric utilities or independent power producers that have ceased producing electricity prior to October 19, 2015.

(f) This subpart does not apply to wastes, including fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated at facilities that are not part of an electric utility or independent power producer, such as manufacturing facilities, universities, and hospitals. This subpart also does not apply to fly ash, bottom ash, boiler slag, and flue gas desulfurization materials, generated primarily from the combustion of fuels (including other fossil fuels) other than coal, for the purpose of generating electricity unless the fuel burned consists of more than fifty percent (50%) coal on a total heat input or mass input basis, whichever results in the greater mass feed rate of coal.

(g) This subpart does not apply to practices that meet the definition of a beneficial use of CCR.

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(h) This subpart does not apply to CCR placement at active or abandoned underground or surface coal mines.

(i) This subpart does not apply to municipal solid waste landfills that receive CCR.

**§ 257.51 Effective date of this subpart.**

The requirements of this subpart take effect on October 19, 2015.

**§ 257.52 Applicability of other regulations.**

(a) Compliance with the requirements of this subpart does not affect the need for the owner or operator of a CCR landfill, CCR surface impoundment, or lateral expansion of a CCR unit to comply with all other applicable federal, state, tribal, or local laws or other requirements.

(b) Any CCR landfill, CCR surface impoundment, or lateral expansion of a CCR unit continues to be subject to the requirements in §§ 257.3–1, 257.3–2, and 257.3–3.

**§ 257.53 Definitions.**

The following definitions apply to this subpart. Terms not defined in this section have the meaning given by RCRA.

*Acre foot* means the volume of one acre of surface area to a depth of one foot.

*Active facility* or *active electric utilities or independent power producers* means any facility subject to the requirements of this subpart that is in operation on October 14, 2015. An electric utility or independent power producer is in operation if it is generating electricity that is provided to electric power transmission systems or to electric power distribution systems on or after October 14, 2015. An off-site disposal facility is in operation if it is accepting or managing CCR on or after October 14, 2015.

*Active life* or *in operation* means the period of operation beginning with the initial placement of CCR in the CCR unit and ending at completion of closure activities in accordance with § 257.102.

*Active portion* means that part of the CCR unit that has received or is receiving CCR or non-CCR waste and that has not completed closure in accordance with § 257.102.

*Aquifer* means a geologic formation, group of formations, or portion of a formation capable of yielding usable quantities of groundwater to wells or springs.

*Area-capacity curves* means graphic curves which readily show the reservoir water surface area, in acres, at different elevations from the bottom of the reservoir to the maximum water surface, and the capacity or volume, in acre-feet, of the water contained in the reservoir at various elevations.

*Areas susceptible to mass movement* means those areas of influence (*i.e.,* areas characterized as having an active or substantial possibility of mass movement) where, because of natural or human-induced events, the movement of earthen material at, beneath, or adjacent to the CCR unit results in the downslope transport of soil and rock material by means of gravitational influence. Areas of mass movement include, but are not limited to, landslides, avalanches, debris slides and flows, soil fluctuation, block sliding, and rock fall.

*Beneficial use of CCR* means the CCR meet all of the following conditions:

(1) The CCR must provide a functional benefit;

(2) The CCR must substitute for the use of a virgin material, conserving natural resources that would otherwise need to be obtained through practices, such as extraction;

(3) The use of the CCR must meet relevant product specifications, regulatory standards or design standards when available, and when such standards are not available, the CCR is not used in excess quantities; and

(4) When unencapsulated use of CCR involving placement on the land of 12,400 tons or more in non-roadway applications, the user must demonstrate and keep records, and provide such documentation upon request, that environmental releases to groundwater, surface water, soil and air are comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use.

*Closed* means placement of CCR in a CCR unit has ceased, and the owner or operator has completed closure of the CCR unit in accordance with § 257.102 and has initiated post-closure care in accordance with § 257.104.

*Coal combustion residuals (CCR)* means fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated from burning coal for the purpose of generating electricity by electric utilities and independent power producers.

*CCR fugitive dust* means solid airborne particulate matter that contains or is derived from CCR, emitted from any source other than a stack or chimney.

*CCR landfill or landfill* means an area of land or an excavation that receives CCR and which is not a surface impoundment, an underground injection well, a salt dome formation, a salt bed formation, an underground or surface coal mine, or a cave. For purposes of this subpart, a CCR landfill also includes sand and gravel pits and quarries that receive CCR, CCR piles, and any practice that does not meet the definition of a beneficial use of CCR.

*CCR pile or pile* means any non-containerized accumulation of solid, non-flowing CCR that is placed on the land. CCR that is beneficially used off-site is not a CCR pile.

*CCR surface impoundment or impoundment* means a natural topographic depression, man-made excavation, or diked area, which is designed to hold an accumulation of CCR and liquids, and the unit treats, stores, or disposes of CCR.

*CCR unit* means any CCR landfill, CCR surface impoundment, or lateral expansion of a CCR unit, or a combination of more than one of these units, based on the context of the paragraph(s) in which it is used. This term includes both new and existing units, unless otherwise specified.

*Dike* means an embankment, berm, or ridge of either natural or man-made materials used to prevent the movement of liquids, sludges, solids, or other materials.

*Displacement* means the relative movement of any two sides of a fault measured in any direction.

*Disposal* means the discharge, deposit, injection, dumping, spilling, leaking, or placing of any solid waste as defined in section 1004(27) of the Resource Conservation and Recovery Act into or on any land or water so that such solid waste, or constituent thereof, may enter the environment or be emitted into the air or discharged into any waters, including groundwaters. For purposes of this subpart, disposal does not include the storage or the beneficial use of CCR.

*Downstream toe* means the junction of the downstream slope or face of the CCR surface impoundment with the ground surface.

*Encapsulated beneficial use* means a beneficial use of CCR that binds the CCR into a solid matrix that minimizes its mobilization into the surrounding environment.

*Existing CCR landfill* means a CCR landfill that receives CCR both before and after October 14, 2015, or for which construction commenced prior to October 14, 2015 and receives CCR on or after October 14, 2015. A CCR landfill has commenced construction if the owner or operator has obtained the federal, state, and local approvals or permits necessary to begin physical

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construction and a continuous on-site, physical construction program had begun prior to October 14, 2015.

*Existing CCR surface impoundment* means a CCR surface impoundment that receives CCR both before and after October 14, 2015, or for which construction commenced prior to October 14, 2015 and receives CCR on or after October 14, 2015. A CCR surface impoundment has commenced construction if the owner or operator has obtained the federal, state, and local approvals or permits necessary to begin physical construction and a continuous on-site, physical construction program had begun prior to October 14, 2015.

*Facility* means all contiguous land, and structures, other appurtenances, and improvements on the land, used for treating, storing, disposing, or otherwise conducting solid waste management of CCR. A facility may consist of several treatment, storage, or disposal operational units (*e.g.,* one or more landfills, surface impoundments, or combinations of them).

*Factor of safety (Safety factor)* means the ratio of the forces tending to resist the failure of a structure to the forces tending to cause such failure as determined by accepted engineering practice.

*Fault* means a fracture or a zone of fractures in any material along which strata on one side have been displaced with respect to that on the other side.

*Flood hydrograph* means a graph showing, for a given point on a stream, the discharge, height, or other characteristic of a flood as a function of time.

*Freeboard* means the vertical distance between the lowest point on the crest of the impoundment dike and the surface of the waste contained therein.

*Free liquids* means liquids that readily separate from the solid portion of a waste under ambient temperature and pressure.

*Groundwater* means water below the land surface in a zone of saturation.

*Hazard potential classification* means the possible adverse incremental consequences that result from the release of water or stored contents due to failure of the diked CCR surface impoundment or mis-operation of the diked CCR surface impoundment or its appurtenances. The hazardous potential classifications include high hazard potential CCR surface impoundment, significant hazard potential CCR surface impoundment, and low hazard potential CCR surface impoundment, which terms mean:

(1) *High hazard potential CCR surface impoundment* means a diked surface impoundment where failure or mis-operation will probably cause loss of human life.

(2) *Low hazard potential CCR surface impoundment* means a diked surface impoundment where failure or mis-operation results in no probable loss of human life and low economic and/or environmental losses. Losses are principally limited to the surface impoundment owner's property.

(3) *Significant hazard potential CCR surface impoundment* means a diked surface impoundment where failure or mis-operation results in no probable loss of human life, but can cause economic loss, environmental damage, disruption of lifeline facilities, or impact other concerns.

*Height* means the vertical measurement from the downstream toe of the CCR surface impoundment at its lowest point to the lowest elevation of the crest of the CCR surface impoundment.

*Holocene* means the most recent epoch of the Quaternary period, extending from the end of the Pleistocene Epoch, at 11,700 years before present, to present.

*Hydraulic conductivity* means the rate at which water can move through a permeable medium (*i.e.,* the coefficient of permeability).

*Inactive CCR surface impoundment* means a CCR surface impoundment that no longer receives CCR on or after October 14, 2015 and still contains both CCR and liquids on or after October 14, 2015.

*Incised CCR surface impoundment* means a CCR surface impoundment which is constructed by excavating entirely below the natural ground surface, holds an accumulation of CCR entirely below the adjacent natural ground surface, and does not consist of any constructed diked portion.

*Indian country* or *Indian lands* means:

(1) All land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and including rights-of-way running throughout the reservation;

(2) All dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of the State; and

(3) All Indian allotments, the Indian titles to which have not been extinguished, including rights of way running through the same.

*Indian Tribe* or *Tribe* means any Indian tribe, band, nation, or community recognized by the Secretary of the Interior and exercising substantial governmental duties and powers on Indian lands.

*Inflow design flood* means the flood hydrograph that is used in the design or modification of the CCR surface impoundments and its appurtenant works.

*In operation* means the same as *active life.*

*Karst terrain* means an area where karst topography, with its characteristic erosional surface and subterranean features, is developed as the result of dissolution of limestone, dolomite, or other soluble rock. Characteristic physiographic features present in karst terranes include, but are not limited to, dolines, collapse shafts (sinkholes), sinking streams, caves, seeps, large springs, and blind valleys.

*Lateral expansion* means a horizontal expansion of the waste boundaries of an existing CCR landfill or existing CCR surface impoundment made after October 14, 2015.

*Liquefaction factor of safety* means the factor of safety (safety factor) determined using analysis under liquefaction conditions.

*Lithified earth material* means all rock, including all naturally occurring and naturally formed aggregates or masses of minerals or small particles of older rock that formed by crystallization of magma or by induration of loose sediments. This term does not include man-made materials, such as fill, concrete, and asphalt, or unconsolidated earth materials, soil, or regolith lying at or near the earth surface.

*Maximum horizontal acceleration in lithified earth material* means the maximum expected horizontal acceleration at the ground surface as depicted on a seismic hazard map, with a 98% or greater probability that the acceleration will not be exceeded in 50 years, or the maximum expected horizontal acceleration based on a site-specific seismic risk assessment.

*New CCR landfill* means a CCR landfill or lateral expansion of a CCR landfill that first receives CCR or commences construction after October 14, 2015. A new CCR landfill has commenced construction if the owner or operator has obtained the federal, state, and local approvals or permits necessary to begin physical construction and a continuous on-site, physical construction program had begun after October 14, 2015. Overfills are also considered new CCR landfills.

*New CCR surface impoundment* means a CCR surface impoundment or lateral expansion of an existing or new CCR surface impoundment that first receives CCR or commences construction after October 14, 2015. A

new CCR surface impoundment has commenced construction if the owner or operator has obtained the federal, state, and local approvals or permits necessary to begin physical construction and a continuous on-site, physical construction program had begun after October 14, 2015.

*Operator* means the person(s) responsible for the overall operation of a CCR unit.

*Overfill* means a new CCR landfill constructed over a closed CCR surface impoundment.

*Owner* means the person(s) who owns a CCR unit or part of a CCR unit.

*Poor foundation conditions* mean those areas where features exist which indicate that a natural or human-induced event may result in inadequate foundation support for the structural components of an existing or new CCR unit. For example, failure to maintain static and seismic factors of safety as required in §§ 257.73(e) and 257.74(e) would cause a poor foundation condition.

*Probable maximum flood* means the flood that may be expected from the most severe combination of critical meteorologic and hydrologic conditions that are reasonably possible in the drainage basin.

*Qualified person* means a person or persons trained to recognize specific appearances of structural weakness and other conditions which are disrupting or have the potential to disrupt the operation or safety of the CCR unit by visual observation and, if applicable, to monitor instrumentation.

*Qualified professional engineer* means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in the state where the CCR unit(s) is located.

*Recognized and generally accepted good engineering practices* means engineering maintenance or operation activities based on established codes, widely accepted standards, published technical reports, or a practice widely recommended throughout the industry. Such practices generally detail approved ways to perform specific engineering, inspection, or mechanical integrity activities.

*Retrofit* means to remove all CCR and contaminated soils and sediments from the CCR surface impoundment, and to ensure the unit complies with the requirements in § 257.72

*Representative sample* means a sample of a universe or whole (*e.g.,* waste pile, lagoon, and groundwater) which can be expected to exhibit the average properties of the universe or whole. See EPA publication SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Chapter 9 (available at *http://www.epa.gov/epawaste/hazard/testmethods/sw846/online/index.htm*) for a discussion and examples of representative samples.

*Run-off* means any rainwater, leachate, or other liquid that drains over land from any part of a CCR landfill or lateral expansion of a CCR landfill.

*Run-on* means any rainwater, leachate, or other liquid that drains over land onto any part of a CCR landfill or lateral expansion of a CCR landfill.

*Sand and gravel pit or quarry* means an excavation for the extraction of aggregate, minerals or metals. The term sand and gravel pit and/or quarry does not include subsurface or surface coal mines.

*Seismic factor of safety* means the factor of safety (safety factor) determined using analysis under earthquake conditions using the peak ground acceleration for a seismic event with a 2% probability of exceedance in 50 years, equivalent to a return period of approximately 2,500 years, based on the U.S. Geological Survey (USGS) seismic hazard maps for seismic events with this return period for the region where the CCR surface impoundment is located.

*Seismic impact zone* means an area having a 2% or greater probability that the maximum expected horizontal acceleration, expressed as a percentage of the earth's gravitational pull (g), will exceed 0.10 g in 50 years.

*Slope protection* means engineered or non-engineered measures installed on the upstream or downstream slope of the CCR surface impoundment to protect the slope against wave action or erosion, including but not limited to rock riprap, wooden pile, or concrete revetments, vegetated wave berms, concrete facing, gabions, geotextiles, or fascines.

*Solid waste management or management* means the systematic administration of the activities which provide for the collection, source separation, storage, transportation, processing, treatment, or disposal of solid waste.

*State* means any of the fifty States in addition to the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands.

*State Director* means the chief administrative officer of the lead state agency responsible for implementing the state program regulating disposal in CCR landfills, CCR surface impoundments, and all lateral expansions of a CCR unit.

*Static factor of safety* means the factor of safety (safety factor) determined using analysis under the long-term, maximum storage pool loading condition, the maximum surcharge pool loading condition, and under the end-of-construction loading condition.

*Structural components* mean liners, leachate collection and removal systems, final covers, run-on and run-off systems, inflow design flood control systems, and any other component used in the construction and operation of the CCR unit that is necessary to ensure the integrity of the unit and that the contents of the unit are not released into the environment.

*Unstable area* means a location that is susceptible to natural or human-induced events or forces capable of impairing the integrity, including structural components of some or all of the CCR unit that are responsible for preventing releases from such unit. Unstable areas can include poor foundation conditions, areas susceptible to mass movements, and karst terrains.

*Uppermost aquifer* means the geologic formation nearest the natural ground surface that is an aquifer, as well as lower aquifers that are hydraulically interconnected with this aquifer within the facility's property boundary. Upper limit is measured at a point nearest to the natural ground surface to which the aquifer rises during the wet season.

*Waste boundary* means a vertical surface located at the hydraulically downgradient limit of the CCR unit. The vertical surface extends down into the uppermost aquifer.

### Location Restrictions

#### § 257.60 Placement above the uppermost aquifer.

(a) New CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units must be constructed with a base that is located no less than 1.52 meters (five feet) above the upper limit of the uppermost aquifer, or must demonstrate that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the CCR unit and the uppermost aquifer due to normal fluctuations in groundwater elevations (including the seasonal high water table). The owner or operator must demonstrate by the dates specified in paragraph (c) of this section

that the CCR unit meets the minimum requirements for placement above the uppermost aquifer.

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the demonstration meets the requirements of paragraph (a) of this section.

(c) The owner or operator of the CCR unit must complete the demonstration required by paragraph (a) of this section by the date specified in either paragraph (c)(1) or (2) of this section.

(1) For an existing CCR surface impoundment, the owner or operator must complete the demonstration no later than October 17, 2018.

(2) For a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit, the owner or operator must complete the demonstration no later than the date of initial receipt of CCR in the CCR unit.

(3) The owner or operator has completed the demonstration required by paragraph (a) of this section when the demonstration is placed in the facility's operating record as required by § 257.105(e).

(4) An owner or operator of an existing CCR surface impoundment who fails to demonstrate compliance with the requirements of paragraph (a) of this section by the date specified in paragraph (c)(1) of this section is subject to the requirements of § 257.101(b)(1).

(5) An owner or operator of a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit who fails to make the demonstration showing compliance with the requirements of paragraph (a) of this section is prohibited from placing CCR in the CCR unit.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(e), the notification requirements specified in § 257.106(e), and the internet requirements specified in § 257.107(e).

**§ 257.61 Wetlands.**

(a) New CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units must not be located in wetlands, as defined in § 232.2 of this chapter, unless the owner or operator demonstrates by the dates specified in paragraph (c) of this section that the CCR unit meets the requirements of paragraphs (a)(1) through (5) of this section.

(1) Where applicable under section 404 of the Clean Water Act or applicable state wetlands laws, a clear and objective rebuttal of the presumption that an alternative to the CCR unit is reasonably available that does not involve wetlands.

(2) The construction and operation of the CCR unit will not cause or contribute to any of the following:

(i) A violation of any applicable state or federal water quality standard;

(ii) A violation of any applicable toxic effluent standard or prohibition under section 307 of the Clean Water Act;

(iii) Jeopardize the continued existence of endangered or threatened species or result in the destruction or adverse modification of a critical habitat, protected under the Endangered Species Act of 1973; and

(iv) A violation of any requirement under the Marine Protection, Research, and Sanctuaries Act of 1972 for the protection of a marine sanctuary.

(3) The CCR unit will not cause or contribute to significant degradation of wetlands by addressing all of the following factors:

(i) Erosion, stability, and migration potential of native wetland soils, muds and deposits used to support the CCR unit;

(ii) Erosion, stability, and migration potential of dredged and fill materials used to support the CCR unit;

(iii) The volume and chemical nature of the CCR;

(iv) Impacts on fish, wildlife, and other aquatic resources and their habitat from release of CCR;

(v) The potential effects of catastrophic release of CCR to the wetland and the resulting impacts on the environment; and

(vi) Any additional factors, as necessary, to demonstrate that ecological resources in the wetland are sufficiently protected.

(4) To the extent required under section 404 of the Clean Water Act or applicable state wetlands laws, steps have been taken to attempt to achieve no net loss of wetlands (as defined by acreage and function) by first avoiding impacts to wetlands to the maximum extent reasonable as required by paragraphs (a)(1) through (3) of this section, then minimizing unavoidable impacts to the maximum extent reasonable, and finally offsetting remaining unavoidable wetland impacts through all appropriate and reasonable compensatory mitigation actions (*e.g.*, restoration of existing degraded wetlands or creation of man-made wetlands); and

(5) Sufficient information is available to make a reasoned determination with respect to the demonstrations in paragraphs (a)(1) through (4) of this section.

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the demonstration meets the requirements of paragraph (a) of this section.

(c) The owner or operator of the CCR unit must complete the demonstrations required by paragraph (a) of this section by the date specified in either paragraph (c)(1) or (2) of this section.

(1) For an existing CCR surface impoundment, the owner or operator must complete the demonstration no later than October 17, 2018.

(2) For a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit, the owner or operator must complete the demonstration no later than the date of initial receipt of CCR in the CCR unit.

(3) The owner or operator has completed the demonstration required by paragraph (a) of this section when the demonstration is placed in the facility's operating record as required by § 257.105(e).

(4) An owner or operator of an existing CCR surface impoundment who fails to demonstrate compliance with the requirements of paragraph (a) of this section by the date specified in paragraph (c)(1) of this section is subject to the requirements of § 257.101(b)(1).

(5) An owner or operator of a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit who fails to make the demonstrations showing compliance with the requirements of paragraph (a) of this section is prohibited from placing CCR in the CCR unit.

(d) The owner or operator must comply with the recordkeeping requirements specified in § 257.105(e), the notification requirements specified in § 257.106(e), and the Internet requirements specified in § 257.107(e).

**§ 257.62 Fault areas.**

(a) New CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units must not be located within 60 meters (200 feet) of the outermost damage zone of a fault that has had displacement in Holocene time unless the owner or operator demonstrates by the dates specified in paragraph (c) of this section that an alternative setback distance of less than 60 meters (200 feet) will prevent damage to the structural integrity of the CCR unit.

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the demonstration meets the requirements of paragraph (a) of this section.

(c) The owner or operator of the CCR unit must complete the demonstration

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required by paragraph (a) of this section by the date specified in either paragraph (c)(1) or (2) of this section.

(1) For an existing CCR surface impoundment, the owner or operator must complete the demonstration no later than October 17, 2018.

(2) For a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit, the owner or operator must complete the demonstration no later than the date of initial receipt of CCR in the CCR unit.

(3) The owner or operator has completed the demonstration required by paragraph (a) of this section when the demonstration is placed in the facility's operating record as required by § 257.105(e).

(4) An owner or operator of an existing CCR surface impoundment who fails to demonstrate compliance with the requirements of paragraph (a) of this section by the date specified in paragraph (c)(1) of this section is subject to the requirements of § 257.101(b)(1).

(5) An owner or operator of a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit who fails to make the demonstration showing compliance with the requirements of paragraph (a) of this section is prohibited from placing CCR in the CCR unit.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(e), the notification requirements specified in § 257.106(e), and the Internet requirements specified in § 257.107(e).

**§ 257.63 Seismic impact zones.**

(a) New CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units must not be located in seismic impact zones unless the owner or operator demonstrates by the dates specified in paragraph (c) of this section that all structural components including liners, leachate collection and removal systems, and surface water control systems, are designed to resist the maximum horizontal acceleration in lithified earth material for the site.

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the demonstration meets the requirements of paragraph (a) of this section.

(c) The owner or operator of the CCR unit must complete the demonstration required by paragraph (a) of this section by the date specified in either paragraph (c)(1) or (2) of this section.

(1) For an existing CCR surface impoundment, the owner or operator must complete the demonstration no later than October 17, 2018.

(2) For a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit, the owner or operator must complete the demonstration no later than the date of initial receipt of CCR in the CCR unit.

(3) The owner or operator has completed the demonstration required by paragraph (a) of this section when the demonstration is placed in the facility's operating record as required by § 257.105(e).

(4) An owner or operator of an existing CCR surface impoundment who fails to demonstrate compliance with the requirements of paragraph (a) of this section by the date specified in paragraph (c)(1) of this section is subject to the requirements of § 257.101(b)(1).

(5) An owner or operator of a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit who fails to make the demonstration showing compliance with the requirements of paragraph (a) of this section is prohibited from placing CCR in the CCR unit.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(e), the notification requirements specified in § 257.106(e), and the Internet requirements specified in § 257.107(e).

**§ 257.64 Unstable areas.**

(a) An existing or new CCR landfill, existing or new CCR surface impoundment, or any lateral expansion of a CCR unit must not be located in an unstable area unless the owner or operator demonstrates by the dates specified in paragraph (d) of this section that recognized and generally accepted good engineering practices have been incorporated into the design of the CCR unit to ensure that the integrity of the structural components of the CCR unit will not be disrupted.

(b) The owner or operator must consider all of the following factors, at a minimum, when determining whether an area is unstable:

(1) On-site or local soil conditions that may result in significant differential settling;

(2) On-site or local geologic or geomorphologic features; and

(3) On-site or local human-made features or events (both surface and subsurface).

(c) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the demonstration meets the requirements of paragraph (a) of this section.

(d) The owner or operator of the CCR unit must complete the demonstration required by paragraph (a) of this section by the date specified in either paragraph (d)(1) or (2) of this section.

(1) For an existing CCR landfill or existing CCR surface impoundment, the owner or operator must complete the demonstration no later than October 17, 2018.

(2) For a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit, the owner or operator must complete the demonstration no later than the date of initial receipt of CCR in the CCR unit.

(3) The owner or operator has completed the demonstration required by paragraph (a) of this section when the demonstration is placed in the facility's operating record as required by § 257.105(e).

(4) An owner or operator of an existing CCR surface impoundment or existing CCR landfill who fails to demonstrate compliance with the requirements of paragraph (a) of this section by the date specified in paragraph (d)(1) of this section is subject to the requirements of § 257.101(b)(1) or (d)(1), respectively.

(5) An owner or operator of a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit who fails to make the demonstration showing compliance with the requirements of paragraph (a) of this section is prohibited from placing CCR in the CCR unit.

(e) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(e), the notification requirements specified in § 257.106(e), and the Internet requirements specified in § 257.107(e).

## Design Criteria

**§ 257.70 Design criteria for new CCR landfills and any lateral expansion of a CCR landfill.**

(a)(1) New CCR landfills and any lateral expansion of a CCR landfill must be designed, constructed, operated, and maintained with either a composite liner that meets the requirements of paragraph (b) of this section or an alternative composite liner that meets the requirements in paragraph (c) of this section, and a leachate collection and removal system that meets the requirements of paragraph (d) of this section.

(2) Prior to construction of an overfill the underlying surface impoundment must meet the requirements of § 257.102(d).

(b) A *composite liner* must consist of two components; the upper component

consisting of, at a minimum, a 30-mil geomembrane liner (GM), and the lower component consisting of at least a two-foot layer of compacted soil with a hydraulic conductivity of no more than $1 \times 10^{-7}$ centimeters per second (cm/sec). GM components consisting of high density polyethylene (HDPE) must be at least 60-mil thick. The GM or upper liner component must be installed in direct and uniform contact with the compacted soil or lower liner component. The composite liner must be:

(1) Constructed of materials that have appropriate chemical properties and sufficient strength and thickness to prevent failure due to pressure gradients (including static head and external hydrogeologic forces), physical contact with the CCR or leachate to which they are exposed, climatic conditions, the stress of installation, and the stress of daily operation;

(2) Constructed of materials that provide appropriate shear resistance of the upper and lower component interface to prevent sliding of the upper component including on slopes;

(3) Placed upon a foundation or base capable of providing support to the liner and resistance to pressure gradients above and below the liner to prevent failure of the liner due to settlement, compression, or uplift; and

(4) Installed to cover all surrounding earth likely to be in contact with the CCR or leachate.

(c) If the owner or operator elects to install an alternative composite liner, all of the following requirements must be met:

(1) An *alternative composite liner* must consist of two components; the upper component consisting of, at a minimum, a 30-mil GM, and a lower component, that is not a geomembrane, with a liquid flow rate no greater than the liquid flow rate of two feet of compacted soil with a hydraulic conductivity of no more than $1 \times 10^{-7}$ cm/sec. GM components consisting of high density polyethylene (HDPE) must be at least 60-mil thick. If the lower component of the alternative liner is compacted soil, the GM must be installed in direct and uniform contact with the compacted soil.

(2) The owner or operator must obtain certification from a qualified professional engineer that the liquid flow rate through the lower component of the alternative composite liner is no greater than the liquid flow rate through two feet of compacted soil with a hydraulic conductivity of $1 \times 10^{-7}$ cm/sec. The hydraulic conductivity for the two feet of compacted soil used in the comparison shall be no greater than $1 \times 10^{-7}$ cm/sec. The hydraulic conductivity of any alternative to the two feet of compacted soil must be determined using recognized and generally accepted methods. The liquid flow rate comparison must be made using Equation 1 of this section, which is derived from Darcy's Law for gravity flow through porous media.

$$\text{(Eq. 1)} \qquad \frac{Q}{A} = q = k\left(\frac{h}{t} + 1\right)$$

Where,

Q = flow rate (cubic centimeters/second);
A = surface area of the liner (squared centimeters);
q = flow rate per unit area (cubic centimeters/second/squared centimeter);
k = hydraulic conductivity of the liner (centimeters/second);
h = hydraulic head above the liner (centimeters); and
t = thickness of the liner (centimeters).

(3) The alternative composite liner must meet the requirements specified in paragraphs (b)(1) through (4) of this section.

(d) The *leachate collection and removal system* must be designed, constructed, operated, and maintained to collect and remove leachate from the landfill during the active life and post-closure care period. The leachate collection and removal system must be:

(1) Designed and operated to maintain less than a 30-centimeter depth of leachate over the composite liner or alternative composite liner;

(2) Constructed of materials that are chemically resistant to the CCR and any non-CCR waste managed in the CCR unit and the leachate expected to be generated, and of sufficient strength and thickness to prevent collapse under the pressures exerted by overlying waste, waste cover materials, and equipment used at the CCR unit; and

(3) Designed and operated to minimize clogging during the active life and post-closure care period.

(e) Prior to construction of the CCR landfill or any lateral expansion of a CCR landfill, the owner or operator must obtain a certification from a qualified professional engineer that the design of the composite liner (or, if applicable, alternative composite liner) and the leachate collection and removal system meets the requirements of this section.

(f) Upon completion of construction of the CCR landfill or any lateral expansion of a CCR landfill, the owner or operator must obtain a certification from a qualified professional engineer that the composite liner (or, if applicable, alternative composite liner) and the leachate collection and removal system has been constructed in accordance with the requirements of this section.

(g) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(f), the notification requirements specified in § 257.106(f), and the Internet requirements specified in § 257.107(f).

### § 257.71 Liner design criteria for existing CCR surface impoundments.

(a)(1) No later than October 17, 2016, the owner or operator of an existing CCR surface impoundment must document whether or not such unit was constructed with any one of the following:

(i) A liner consisting of a minimum of two feet of compacted soil with a hydraulic conductivity of no more than $1 \times 10^{-7}$ cm/sec;

(ii) A composite liner that meets the requirements of § 257.70(b); or

(iii) An alternative composite liner that meets the requirements of § 257.70(c).

(2) The hydraulic conductivity of the compacted soil must be determined using recognized and generally accepted methods.

(3) An existing CCR surface impoundment is considered to be an existing unlined CCR surface impoundment if either:

(i) The owner or operator of the CCR unit determines that the CCR unit is not constructed with a liner that meets the requirements of paragraphs (a)(1)(i), (ii), or (iii) of this section; or

(ii) The owner or operator of the CCR unit fails to document whether the CCR unit was constructed with a liner that meets the requirements of paragraphs (a)(1)(i), (ii), or (iii) of this section.

(4) All existing unlined CCR surface impoundments are subject to the requirements of § 257.101(a).

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer attesting that the documentation as to whether a CCR unit meets the requirements of paragraph (a) of this section is accurate.

(c) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(f), the notification requirements specified in § 257.106(f), and the Internet requirements specified in § 257.107(f).

### § 257.72 Liner design criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment.

(a) New CCR surface impoundments and lateral expansions of existing and new CCR surface impoundments must

be designed, constructed, operated, and maintained with either a composite liner or an alternative composite liner that meets the requirements of § 257.70(b) or (c).

(b) Any liner specified in this section must be installed to cover all surrounding earth likely to be in contact with CCR. Dikes shall not be constructed on top of the composite liner.

(c) Prior to construction of the CCR surface impoundment or any lateral expansion of a CCR surface impoundment, the owner or operator must obtain certification from a qualified professional engineer that the design of the composite liner or, if applicable, the design of an alternative composite liner complies with the requirements of this section.

(d) Upon completion, the owner or operator must obtain certification from a qualified professional engineer that the composite liner or if applicable, the alternative composite liner has been constructed in accordance with the requirements of this section.

(e) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(f), the notification requirements specified in § 257.106(f), and the Internet requirements specified in § 257.107(f).

**§ 257.73 Structural integrity criteria for existing CCR surface impoundments.**

(a) The requirements of paragraphs (a)(1) through (4) of this section apply to all existing CCR surface impoundments, except for those existing CCR surface impoundments that are incised CCR units. If an incised CCR surface impoundment is subsequently modified (*e.g.,* a dike is constructed) such that the CCR unit no longer meets the definition of an incised CCR unit, the CCR unit is subject to the requirements of paragraphs (a)(1) through (4) of this section.

(1) No later than, December 17, 2015, the owner or operator of the CCR unit must place on or immediately adjacent to the CCR unit a permanent identification marker, at least six feet high showing the identification number of the CCR unit, if one has been assigned by the state, the name associated with the CCR unit and the name of the owner or operator of the CCR unit.

(2) *Periodic hazard potential classification assessments.* (i) The owner or operator of the CCR unit must conduct initial and periodic hazard potential classification assessments of the CCR unit according to the timeframes specified in paragraph (f) of this section. The owner or operator must document the hazard potential classification of each CCR unit as either a high hazard potential CCR surface impoundment, a significant hazard potential CCR surface impoundment, or a low hazard potential CCR surface impoundment. The owner or operator must also document the basis for each hazard potential classification.

(ii) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the initial hazard potential classification and each subsequent periodic classification specified in paragraph (a)(2)(i) of this section was conducted in accordance with the requirements of this section.

(3) *Emergency Action Plan (EAP)*—(i) *Development of the plan.* No later than April 17, 2017, the owner or operator of a CCR unit determined to be either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment under paragraph (a)(2) of this section must prepare and maintain a written EAP. At a minimum, the EAP must:

(A) Define the events or circumstances involving the CCR unit that represent a safety emergency, along with a description of the procedures that will be followed to detect a safety emergency in a timely manner;

(B) Define responsible persons, their respective responsibilities, and notification procedures in the event of a safety emergency involving the CCR unit;

(C) Provide contact information of emergency responders;

(D) Include a map which delineates the downstream area which would be affected in the event of a CCR unit failure and a physical description of the CCR unit; and

(E) Include provisions for an annual face-to-face meeting or exercise between representatives of the owner or operator of the CCR unit and the local emergency responders.

(ii) *Amendment of the plan.* (A) The owner or operator of a CCR unit subject to the requirements of paragraph (a)(3)(i) of this section may amend the written EAP at any time provided the revised plan is placed in the facility's operating record as required by § 257.105(f)(6). The owner or operator must amend the written EAP whenever there is a change in conditions that would substantially affect the EAP in effect.

(B) The written EAP must be evaluated, at a minimum, every five years to ensure the information required in paragraph (a)(3)(i) of this section is accurate. As necessary, the EAP must be updated and a revised EAP placed in the facility's operating record as required by § 257.105(f)(6).

(iii) *Changes in hazard potential classification.* (A) If the owner or operator of a CCR unit determines during a periodic hazard potential assessment that the CCR unit is no longer classified as either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment, then the owner or operator of the CCR unit is no longer subject to the requirement to prepare and maintain a written EAP beginning on the date the periodic hazard potential assessment documentation is placed in the facility's operating record as required by § 257.105(f)(5).

(B) If the owner or operator of a CCR unit classified as a low hazard potential CCR surface impoundment subsequently determines that the CCR unit is properly re-classified as either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment, then the owner or operator of the CCR unit must prepare a written EAP for the CCR unit as required by paragraph (a)(3)(i) of this section within six months of completing such periodic hazard potential assessment.

(iv) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the written EAP, and any subsequent amendment of the EAP, meets the requirements of paragraph (a)(3) of this section.

(v) *Activation of the EAP.* The EAP must be implemented once events or circumstances involving the CCR unit that represent a safety emergency are detected, including conditions identified during periodic structural stability assessments, annual inspections, and inspections by a qualified person.

(4) The CCR unit and surrounding areas must be designed, constructed, operated, and maintained with vegetated slopes of dikes not to exceed a height of 6 inches above the slope of the dike, except for slopes which are protected with an alternate form(s) of slope protection.

(b) The requirements of paragraphs (c) through (e) of this section apply to an owner or operator of an existing CCR surface impoundment that either:

(1) Has a height of five feet or more and a storage volume of 20 acre-feet or more; or

(2) Has a height of 20 feet or more.

(c)(1) No later than October 17, 2016, the owner or operator of the CCR unit must compile a history of construction, which shall contain, to the extent feasible, the information specified in

paragraphs (c)(1)(i) through (xi) of this section.

(i) The name and address of the person(s) owning or operating the CCR unit; the name associated with the CCR unit; and the identification number of the CCR unit if one has been assigned by the state.

(ii) The location of the CCR unit identified on the most recent U.S. Geological Survey (USGS) 7½ minute or 15 minute topographic quadrangle map, or a topographic map of equivalent scale if a USGS map is not available.

(iii) A statement of the purpose for which the CCR unit is being used.

(iv) The name and size in acres of the watershed within which the CCR unit is located.

(v) A description of the physical and engineering properties of the foundation and abutment materials on which the CCR unit is constructed.

(vi) A statement of the type, size, range, and physical and engineering properties of the materials used in constructing each zone or stage of the CCR unit; the method of site preparation and construction of each zone of the CCR unit; and the approximate dates of construction of each successive stage of construction of the CCR unit.

(vii) At a scale that details engineering structures and appurtenances relevant to the design, construction, operation, and maintenance of the CCR unit, detailed dimensional drawings of the CCR unit, including a plan view and cross sections of the length and width of the CCR unit, showing all zones, foundation improvements, drainage provisions, spillways, diversion ditches, outlets, instrument locations, and slope protection, in addition to the normal operating pool surface elevation and the maximum pool surface elevation following peak discharge from the inflow design flood, the expected maximum depth of CCR within the CCR surface impoundment, and any identifiable natural or manmade features that could adversely affect operation of the CCR unit due to malfunction or mis-operation.

(viii) A description of the type, purpose, and location of existing instrumentation.

(ix) Area-capacity curves for the CCR unit.

(x) A description of each spillway and diversion design features and capacities and calculations used in their determination.

(xi) The construction specifications and provisions for surveillance, maintenance, and repair of the CCR unit.

(xii) Any record or knowledge of structural instability of the CCR unit.

(2) *Changes to the history of construction.* If there is a significant change to any information compiled under paragraph (c)(1) of this section, the owner or operator of the CCR unit must update the relevant information and place it in the facility's operating record as required by § 257.105(f)(9).

(d) *Periodic structural stability assessments.* (1) The owner or operator of the CCR unit must conduct initial and periodic structural stability assessments and document whether the design, construction, operation, and maintenance of the CCR unit is consistent with recognized and generally accepted good engineering practices for the maximum volume of CCR and CCR wastewater which can be impounded therein. The assessment must, at a minimum, document whether the CCR unit has been designed, constructed, operated, and maintained with:

(i) Stable foundations and abutments;

(ii) Adequate slope protection to protect against surface erosion, wave action, and adverse effects of sudden drawdown;

(iii) Dikes mechanically compacted to a density sufficient to withstand the range of loading conditions in the CCR unit;

(iv) Vegetated slopes of dikes and surrounding areas not to exceed a height of six inches above the slope of the dike, except for slopes which have an alternate form or forms of slope protection;

(v) A single spillway or a combination of spillways configured as specified in paragraph (d)(1)(v)(A) of this section. The combined capacity of all spillways must be designed, constructed, operated, and maintained to adequately manage flow during and following the peak discharge from the event specified in paragraph (d)(1)(v)(B) of this section.

(A) All spillways must be either:

(*1*) Of non-erodible construction and designed to carry sustained flows; or

(*2*) Earth- or grass-lined and designed to carry short-term, infrequent flows at non-erosive velocities where sustained flows are not expected.

(B) The combined capacity of all spillways must adequately manage flow during and following the peak discharge from a:

(*1*) Probable maximum flood (PMF) for a high hazard potential CCR surface impoundment; or

(*2*) 1000-year flood for a significant hazard potential CCR surface impoundment; or

(*3*) 100-year flood for a low hazard potential CCR surface impoundment.

(vi) Hydraulic structures underlying the base of the CCR unit or passing through the dike of the CCR unit that maintain structural integrity and are free of significant deterioration, deformation, distortion, bedding deficiencies, sedimentation, and debris which may negatively affect the operation of the hydraulic structure; and

(vii) For CCR units with downstream slopes which can be inundated by the pool of an adjacent water body, such as a river, stream or lake, downstream slopes that maintain structural stability during low pool of the adjacent water body or sudden drawdown of the adjacent water body.

(2) The periodic assessment described in paragraph (d)(1) of this section must identify any structural stability deficiencies associated with the CCR unit in addition to recommending corrective measures. If a deficiency or a release is identified during the periodic assessment, the owner or operator unit must remedy the deficiency or release as soon as feasible and prepare documentation detailing the corrective measures taken.

(3) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the initial assessment and each subsequent periodic assessment was conducted in accordance with the requirements of this section.

(e) *Periodic safety factor assessments.* (1) The owner or operator must conduct an initial and periodic safety factor assessments for each CCR unit and document whether the calculated factors of safety for each CCR unit achieve the minimum safety factors specified in paragraphs (e)(1)(i) through (iv) of this section for the critical cross section of the embankment. The critical cross section is the cross section anticipated to be the most susceptible of all cross sections to structural failure based on appropriate engineering considerations, including loading conditions. The safety factor assessments must be supported by appropriate engineering calculations.

(i) The calculated static factor of safety under the long-term, maximum storage pool loading condition must equal or exceed 1.50.

(ii) The calculated static factor of safety under the maximum surcharge pool loading condition must equal or exceed 1.40.

(iii) The calculated seismic factor of safety must equal or exceed 1.00.

(iv) For dikes constructed of soils that have susceptibility to liquefaction, the calculated liquefaction factor of safety must equal or exceed 1.20.

(2) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating

that the initial assessment and each subsequent periodic assessment specified in paragraph (e)(1) of this section meets the requirements of this section.

(f) *Timeframes for periodic assessments*—(1) *Initial assessments.* Except as provided by paragraph (f)(2) of this section, the owner or operator of the CCR unit must complete the initial assessments required by paragraphs (a)(2), (d), and (e) of this section no later than October 17, 2016. The owner or operator has completed an initial assessment when the owner or operator has placed the assessment required by paragraphs (a)(2), (d), and (e) of this section in the facility's operating record as required by § 257.105(f)(5), (10), and (12).

(2) *Use of a previously completed assessment(s) in lieu of the initial assessment(s).* The owner or operator of the CCR unit may elect to use a previously completed assessment to serve as the initial assessment required by paragraphs (a)(2), (d), and (e) of this section provided that the previously completed assessment(s):

(i) Was completed no earlier than 42 months prior to October 17, 2016; and

(ii) Meets the applicable requirements of paragraphs (a)(2), (d), and (e) of this section.

(3) *Frequency for conducting periodic assessments.* The owner or operator of the CCR unit must conduct and complete the assessments required by paragraphs (a)(2), (d), and (e) of this section every five years. The date of completing the initial assessment is the basis for establishing the deadline to complete the first subsequent assessment. If the owner or operator elects to use a previously completed assessment(s) in lieu of the initial assessment as provided by paragraph (f)(2) of this section, the date of the report for the previously completed assessment is the basis for establishing the deadline to complete the first subsequent assessment. The owner or operator may complete any required assessment prior to the required deadline provided the owner or operator places the completed assessment(s) into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing subsequent assessments is based on the date of completing the previous assessment. For purposes of this paragraph (f)(3), the owner or operator has completed an assessment when the relevant assessment(s) required by paragraphs (a)(2), (d), and (e) of this section has been placed in the facility's operating record as required by § 257.105(f)(5), (10), and (12).

(4) *Closure of the CCR unit.* An owner or operator of a CCR unit who either fails to complete a timely safety factor assessment or fails to demonstrate minimum safety factors as required by paragraph (e) of this section is subject to the requirements of § 257.101(b)(2).

(g) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(f), the notification requirements specified in § 257.106(f), and the internet requirements specified in § 257.107(f).

**§ 257.74 Structural integrity criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment.**

(a) The requirements of paragraphs (a)(1) through (4) of this section apply to all new CCR surface impoundments and any lateral expansion of a CCR surface impoundment, except for those new CCR surface impoundments that are incised CCR units. If an incised CCR surface impoundment is subsequently modified (*e.g.,* a dike is constructed) such that the CCR unit no longer meets the definition of an incised CCR unit, the CCR unit is subject to the requirements of paragraphs (a)(1) through (4) of this section.

(1) No later than the initial receipt of CCR, the owner or operator of the CCR unit must place on or immediately adjacent to the CCR unit a permanent identification marker, at least six feet high showing the identification number of the CCR unit, if one has been assigned by the state, the name associated with the CCR unit and the name of the owner or operator of the CCR unit.

(2) *Periodic hazard potential classification assessments.* (i) The owner or operator of the CCR unit must conduct initial and periodic hazard potential classification assessments of the CCR unit according to the timeframes specified in paragraph (f) of this section. The owner or operator must document the hazard potential classification of each CCR unit as either a high hazard potential CCR surface impoundment, a significant hazard potential CCR surface impoundment, or a low hazard potential CCR surface impoundment. The owner or operator must also document the basis for each hazard potential classification.

(ii) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the initial hazard potential classification and each subsequent periodic classification specified in paragraph (a)(2)(i) of this section was conducted in accordance with the requirements of this section.

(3) *Emergency Action Plan (EAP)*—(i) *Development of the plan.* Prior to the initial receipt of CCR in the CCR unit, the owner or operator of a CCR unit determined to be either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment under paragraph (a)(2) of this section must prepare and maintain a written EAP. At a minimum, the EAP must:

(A) Define the events or circumstances involving the CCR unit that represent a safety emergency, along with a description of the procedures that will be followed to detect a safety emergency in a timely manner;

(B) Define responsible persons, their respective responsibilities, and notification procedures in the event of a safety emergency involving the CCR unit;

(C) Provide contact information of emergency responders;

(D) Include a map which delineates the downstream area which would be affected in the event of a CCR unit failure and a physical description of the CCR unit; and

(E) Include provisions for an annual face-to-face meeting or exercise between representatives of the owner or operator of the CCR unit and the local emergency responders.

(ii) *Amendment of the plan.* (A) The owner or operator of a CCR unit subject to the requirements of paragraph (a)(3)(i) of this section may amend the written EAP at any time provided the revised plan is placed in the facility's operating record as required by § 257.105(f)(6). The owner or operator must amend the written EAP whenever there is a change in conditions that would substantially affect the EAP in effect.

(B) The written EAP must be evaluated, at a minimum, every five years to ensure the information required in paragraph (a)(3)(i) of this section is accurate. As necessary, the EAP must be updated and a revised EAP placed in the facility's operating record as required by § 257.105(f)(6).

(iii) *Changes in hazard potential classification.* (A) If the owner or operator of a CCR unit determines during a periodic hazard potential assessment that the CCR unit is no longer classified as either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment, then the owner or operator of the CCR unit is no longer subject to the requirement to prepare and maintain a written EAP beginning on the date the periodic hazard potential assessment documentation is

placed in the facility's operating record as required by § 257.105(f)(5).

(B) If the owner or operator of a CCR unit classified as a low hazard potential CCR surface impoundment subsequently determines that the CCR unit is properly re-classified as either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment, then the owner or operator of the CCR unit must prepare a written EAP for the CCR unit as required by paragraph (a)(3)(i) of this section within six months of completing such periodic hazard potential assessment.

(iv) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the written EAP, and any subsequent amendment of the EAP, meets the requirements of paragraph (a)(3) of this section.

(v) *Activation of the EAP.* The EAP must be implemented once events or circumstances involving the CCR unit that represent a safety emergency are detected, including conditions identified during periodic structural stability assessments, annual inspections, and inspections by a qualified person.

(4) The CCR unit and surrounding areas must be designed, constructed, operated, and maintained with vegetated slopes of dikes not to exceed a height of six inches above the slope of the dike, except for slopes which are protected with an alternate form(s) of slope protection.

(b) The requirements of paragraphs (c) through (e) of this section apply to an owner or operator of a new CCR surface impoundment and any lateral expansion of a CCR surface impoundment that either:

(1) Has a height of five feet or more and a storage volume of 20 acre-feet or more; or

(2) Has a height of 20 feet or more.

(c)(1) No later than the initial receipt of CCR in the CCR unit, the owner or operator unit must compile the design and construction plans for the CCR unit, which must include, to the extent feasible, the information specified in paragraphs (c)(1)(i) through (xi) of this section.

(i) The name and address of the person(s) owning or operating the CCR unit; the name associated with the CCR unit; and the identification number of the CCR unit if one has been assigned by the state.

(ii) The location of the CCR unit identified on the most recent U.S. Geological Survey (USGS) 7½ minute or 15 minute topographic quadrangle map, or a topographic map of equivalent scale if a USGS map is not available.

(iii) A statement of the purpose for which the CCR unit is being used.

(iv) The name and size in acres of the watershed within which the CCR unit is located.

(v) A description of the physical and engineering properties of the foundation and abutment materials on which the CCR unit is constructed.

(vi) A statement of the type, size, range, and physical and engineering properties of the materials used in constructing each zone or stage of the CCR unit; the method of site preparation and construction of each zone of the CCR unit; and the dates of construction of each successive stage of construction of the CCR unit.

(vii) At a scale that details engineering structures and appurtenances relevant to the design, construction, operation, and maintenance of the CCR unit, detailed dimensional drawings of the CCR unit, including a plan view and cross sections of the length and width of the CCR unit, showing all zones, foundation improvements, drainage provisions, spillways, diversion ditches, outlets, instrument locations, and slope protection, in addition to the normal operating pool surface elevation and the maximum pool surface elevation following peak discharge from the inflow design flood, the expected maximum depth of CCR within the CCR surface impoundment, and any identifiable natural or manmade features that could adversely affect operation of the CCR unit due to malfunction or mis-operation.

(viii) A description of the type, purpose, and location of existing instrumentation.

(ix) Area-capacity curves for the CCR unit.

(x) A description of each spillway and diversion design features and capacities and calculations used in their determination.

(xi) The construction specifications and provisions for surveillance, maintenance, and repair of the CCR unit.

(xii) Any record or knowledge of structural instability of the CCR unit.

(2) *Changes in the design and construction.* If there is a significant change to any information compiled under paragraph (c)(1) of this section, the owner or operator of the CCR unit must update the relevant information and place it in the facility's operating record as required by § 257.105(f)(13).

(d) *Periodic structural stability assessments.* (1) The owner or operator of the CCR unit must conduct initial and periodic structural stability assessments and document whether the design, construction, operation, and maintenance of the CCR unit is consistent with recognized and generally accepted good engineering practices for the maximum volume of CCR and CCR wastewater which can be impounded therein. The assessment must, at a minimum, document whether the CCR unit has been designed, constructed, operated, and maintained with:

(i) Stable foundations and abutments;

(ii) Adequate slope protection to protect against surface erosion, wave action, and adverse effects of sudden drawdown;

(iii) Dikes mechanically compacted to a density sufficient to withstand the range of loading conditions in the CCR unit;

(iv) Vegetated slopes of dikes and surrounding areas not to exceed a height of six inches above the slope of the dike, except for slopes which have an alternate form or forms of slope protection;

(v) A single spillway or a combination of spillways configured as specified in paragraph (d)(1)(v)(A) of this section. The combined capacity of all spillways must be designed, constructed, operated, and maintained to adequately manage flow during and following the peak discharge from the event specified in paragraph (d)(1)(v)(B) of this section.

(A) All spillways must be either:

(*1*) Of non-erodible construction and designed to carry sustained flows; or

(*2*) Earth- or grass-lined and designed to carry short-term, infrequent flows at non-erosive velocities where sustained flows are not expected.

(B) The combined capacity of all spillways must adequately manage flow during and following the peak discharge from a:

(*1*) Probable maximum flood (PMF) for a high hazard potential CCR surface impoundment; or

(*2*) 1000-year flood for a significant hazard potential CCR surface impoundment; or

(*3*) 100-year flood for a low hazard potential CCR surface impoundment.

(vi) Hydraulic structures underlying the base of the CCR unit or passing through the dike of the CCR unit that maintain structural integrity and are free of significant deterioration, deformation, distortion, bedding deficiencies, sedimentation, and debris which may negatively affect the operation of the hydraulic structure; and

(vii) For CCR units with downstream slopes which can be inundated by the pool of an adjacent water body, such as a river, stream or lake, downstream slopes that maintain structural stability

during low pool of the adjacent water body or sudden drawdown of the adjacent water body.

(2) The periodic assessment described in paragraph (d)(1) of this section must identify any structural stability deficiencies associated with the CCR unit in addition to recommending corrective measures. If a deficiency or a release is identified during the periodic assessment, the owner or operator unit must remedy the deficiency or release as soon as feasible and prepare documentation detailing the corrective measures taken.

(3) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the initial assessment and each subsequent periodic assessment was conducted in accordance with the requirements of this section.

(e) *Periodic safety factor assessments.* (1) The owner or operator must conduct an initial and periodic safety factor assessments for each CCR unit and document whether the calculated factors of safety for each CCR unit achieve the minimum safety factors specified in paragraphs (e)(1)(i) through (v) of this section for the critical cross section of the embankment. The critical cross section is the cross section anticipated to be the most susceptible of all cross sections to structural failure based on appropriate engineering considerations, including loading conditions. The safety factor assessments must be supported by appropriate engineering calculations.

(i) The calculated static factor of safety under the end-of-construction loading condition must equal or exceed 1.30. The assessment of this loading condition is only required for the initial safety factor assessment and is not required for subsequent assessments.

(ii) The calculated static factor of safety under the long-term, maximum storage pool loading condition must equal or exceed 1.50.

(iii) The calculated static factor of safety under the maximum surcharge pool loading condition must equal or exceed 1.40.

(iv) The calculated seismic factor of safety must equal or exceed 1.00.

(v) For dikes constructed of soils that have susceptibility to liquefaction, the calculated liquefaction factor of safety must equal or exceed 1.20.

(2) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the initial assessment and each subsequent periodic assessment specified in paragraph (e)(1) of this section meets the requirements of this section.

(f) *Timeframes for periodic assessments*—(1) *Initial assessments.* Except as provided by paragraph (f)(2) of this section, the owner or operator of the CCR unit must complete the initial assessments required by paragraphs (a)(2), (d), and (e) of this section prior to the initial receipt of CCR in the unit. The owner or operator has completed an initial assessment when the owner or operator has placed the assessment required by paragraphs (a)(2), (d), and (e) of this section in the facility's operating record as required by § 257.105(f)(5), (10), and (12).

(2) *Frequency for conducting periodic assessments.* The owner or operator of the CCR unit must conduct and complete the assessments required by paragraphs (a)(2), (d), and (e) of this section every five years. The date of completing the initial assessment is the basis for establishing the deadline to complete the first subsequent assessment. The owner or operator may complete any required assessment prior to the required deadline provided the owner or operator places the completed assessment(s) into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing subsequent assessments is based on the date of completing the previous assessment. For purposes of this paragraph (f)(2), the owner or operator has completed an assessment when the relevant assessment(s) required by paragraphs (a)(2), (d), and (e) of this section has been placed in the facility's operating record as required by § 257.105(f)(5), (10), and (12).

(3) *Failure to document minimum safety factors during the initial assessment.* Until the date an owner or operator of a CCR unit documents that the calculated factors of safety achieve the minimum safety factors specified in paragraphs (e)(1)(i) through (v) of this section, the owner or operator is prohibited from placing CCR in such unit.

(4) *Closure of the CCR unit.* An owner or operator of a CCR unit who either fails to complete a timely periodic safety factor assessment or fails to demonstrate minimum safety factors as required by paragraph (e) of this section is subject to the requirements of § 257.101(c).

(g) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(f), the notification requirements specified in § 257.106(f), and the internet requirements specified in § 257.107(f).

**Operating Criteria**

**§ 257.80 Air criteria.**

(a) The owner or operator of a CCR landfill, CCR surface impoundment, or any lateral expansion of a CCR unit must adopt measures that will effectively minimize CCR from becoming airborne at the facility, including CCR fugitive dust originating from CCR units, roads, and other CCR management and material handling activities.

(b) *CCR fugitive dust control plan.* The owner or operator of the CCR unit must prepare and operate in accordance with a CCR fugitive dust control plan as specified in paragraphs (b)(1) through (7) of this section. This requirement applies in addition to, not in place of, any applicable standards under the Occupational Safety and Health Act.

(1) The CCR fugitive dust control plan must identify and describe the CCR fugitive dust control measures the owner or operator will use to minimize CCR from becoming airborne at the facility. The owner or operator must select, and include in the CCR fugitive dust control plan, the CCR fugitive dust control measures that are most appropriate for site conditions, along with an explanation of how the measures selected are applicable and appropriate for site conditions. Examples of control measures that may be appropriate include: Locating CCR inside an enclosure or partial enclosure; operating a water spray or fogging system; reducing fall distances at material drop points; using wind barriers, compaction, or vegetative covers; establishing and enforcing reduced vehicle speed limits; paving and sweeping roads; covering trucks transporting CCR; reducing or halting operations during high wind events; or applying a daily cover.

(2) If the owner or operator operates a CCR landfill or any lateral expansion of a CCR landfill, the CCR fugitive dust control plan must include procedures to emplace CCR as conditioned CCR. Conditioned CCR means wetting CCR with water to a moisture content that will prevent wind dispersal, but will not result in free liquids. In lieu of water, CCR conditioning may be accomplished with an appropriate chemical dust suppression agent.

(3) The CCR fugitive dust control plan must include procedures to log citizen complaints received by the owner or operator involving CCR fugitive dust events at the facility.

(4) The CCR fugitive dust control plan must include a description of the procedures the owner or operator will

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follow to periodically assess the effectiveness of the control plan.

(5) The owner or operator of a CCR unit must prepare an initial CCR fugitive dust control plan for the facility no later than October 19, 2015, or by initial receipt of CCR in any CCR unit at the facility if the owner or operator becomes subject to this subpart after October 19, 2015. The owner or operator has completed the initial CCR fugitive dust control plan when the plan has been placed in the facility's operating record as required by § 257.105(g)(1).

(6) *Amendment of the plan.* The owner or operator of a CCR unit subject to the requirements of this section may amend the written CCR fugitive dust control plan at any time provided the revised plan is placed in the facility's operating record as required by § 257.105(g)(1). The owner or operator must amend the written plan whenever there is a change in conditions that would substantially affect the written plan in effect, such as the construction and operation of a new CCR unit.

(7) The owner or operator must obtain a certification from a qualified professional engineer that the initial CCR fugitive dust control plan, or any subsequent amendment of it, meets the requirements of this section.

(c) *Annual CCR fugitive dust control report.* The owner or operator of a CCR unit must prepare an annual CCR fugitive dust control report that includes a description of the actions taken by the owner or operator to control CCR fugitive dust, a record of all citizen complaints, and a summary of any corrective measures taken. The initial annual report must be completed no later than 14 months after placing the initial CCR fugitive dust control plan in the facility's operating record. The deadline for completing a subsequent report is one year after the date of completing the previous report. For purposes of this paragraph (c), the owner or operator has completed the annual CCR fugitive dust control report when the plan has been placed in the facility's operating record as required by § 257.105(g)(2).

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(g), the notification requirements specified in § 257.106(g), and the internet requirements specified in § 257.107(g).

**§ 257.81 Run-on and run-off controls for CCR landfills.**

(a) The owner or operator of an existing or new CCR landfill or any lateral expansion of a CCR landfill must design, construct, operate, and maintain:

(1) A run-on control system to prevent flow onto the active portion of the CCR unit during the peak discharge from a 24-hour, 25-year storm; and

(2) A run-off control system from the active portion of the CCR unit to collect and control at least the water volume resulting from a 24-hour, 25-year storm.

(b) Run-off from the active portion of the CCR unit must be handled in accordance with the surface water requirements under § 257.3–3.

(c) *Run-on and run-off control system plan*—(1) *Content of the plan.* The owner or operator must prepare initial and periodic run-on and run-off control system plans for the CCR unit according to the timeframes specified in paragraphs (c)(3) and (4) of this section. These plans must document how the run-on and run-off control systems have been designed and constructed to meet the applicable requirements of this section. Each plan must be supported by appropriate engineering calculations. The owner or operator has completed the initial run-on and run-off control system plan when the plan has been placed in the facility's operating record as required by § 257.105(g)(3).

(2) *Amendment of the plan.* The owner or operator may amend the written run-on and run-off control system plan at any time provided the revised plan is placed in the facility's operating record as required by § 257.105(g)(3). The owner or operator must amend the written run-on and run-off control system plan whenever there is a change in conditions that would substantially affect the written plan in effect.

(3) *Timeframes for preparing the initial plan*—(i) *Existing CCR landfills.* The owner or operator of the CCR unit must prepare the initial run-on and run-off control system plan no later than October 17, 2016.

(ii) *New CCR landfills and any lateral expansion of a CCR landfill.* The owner or operator must prepare the initial run-on and run-off control system plan no later than the date of initial receipt of CCR in the CCR unit.

(4) *Frequency for revising the plan.* The owner or operator of the CCR unit must prepare periodic run-on and run-off control system plans required by paragraph (c)(1) of this section every five years. The date of completing the initial plan is the basis for establishing the deadline to complete the first subsequent plan. The owner or operator may complete any required plan prior to the required deadline provided the owner or operator places the completed plan into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing a subsequent plan is based on the date of completing the previous plan. For purposes of this paragraph (c)(4), the owner or operator has completed a periodic run-on and run-off control system plan when the plan has been placed in the facility's operating record as required by § 257.105(g)(3).

(5) The owner or operator must obtain a certification from a qualified professional engineer stating that the initial and periodic run-on and run-off control system plans meet the requirements of this section.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(g), the notification requirements specified in § 257.106(g), and the internet requirements specified in § 257.107(g).

**§ 257.82 Hydrologic and hydraulic capacity requirements for CCR surface impoundments.**

(a) The owner or operator of an existing or new CCR surface impoundment or any lateral expansion of a CCR surface impoundment must design, construct, operate, and maintain an inflow design flood control system as specified in paragraphs (a)(1) and (2) of this section.

(1) The inflow design flood control system must adequately manage flow into the CCR unit during and following the peak discharge of the inflow design flood specified in paragraph (a)(3) of this section.

(2) The inflow design flood control system must adequately manage flow from the CCR unit to collect and control the peak discharge resulting from the inflow design flood specified in paragraph (a)(3) of this section.

(3) The inflow design flood is:

(i) For a high hazard potential CCR surface impoundment, as determined under § 257.73(a)(2) or § 257.74(a)(2), the probable maximum flood;

(ii) For a significant hazard potential CCR surface impoundment, as determined under § 257.73(a)(2) or § 257.74(a)(2), the 1,000-year flood;

(iii) For a low hazard potential CCR surface impoundment, as determined under § 257.73(a)(2) or § 257.74(a)(2), the 100-year flood; or

(iv) For an incised CCR surface impoundment, the 25-year flood.

(b) Discharge from the CCR unit must be handled in accordance with the surface water requirements under § 257.3–3.

(c) *Inflow design flood control system plan*—(1) *Content of the plan.* The owner or operator must prepare initial

and periodic inflow design flood control system plans for the CCR unit according to the timeframes specified in paragraphs (c)(3) and (4) of this section. These plans must document how the inflow design flood control system has been designed and constructed to meet the requirements of this section. Each plan must be supported by appropriate engineering calculations. The owner or operator of the CCR unit has completed the inflow design flood control system plan when the plan has been placed in the facility's operating record as required by § 257.105(g)(4).

(2) *Amendment of the plan.* The owner or operator of the CCR unit may amend the written inflow design flood control system plan at any time provided the revised plan is placed in the facility's operating record as required by § 257.105(g)(4). The owner or operator must amend the written inflow design flood control system plan whenever there is a change in conditions that would substantially affect the written plan in effect.

(3) *Timeframes for preparing the initial plan*—(i) *Existing CCR surface impoundments.* The owner or operator of the CCR unit must prepare the initial inflow design flood control system plan no later than October 17, 2016.

(ii) *New CCR surface impoundments and any lateral expansion of a CCR surface impoundment.* The owner or operator must prepare the initial inflow design flood control system plan no later than the date of initial receipt of CCR in the CCR unit.

(4) *Frequency for revising the plan.* The owner or operator must prepare periodic inflow design flood control system plans required by paragraph (c)(1) of this section every five years. The date of completing the initial plan is the basis for establishing the deadline to complete the first periodic plan. The owner or operator may complete any required plan prior to the required deadline provided the owner or operator places the completed plan into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing a subsequent plan is based on the date of completing the previous plan. For purposes of this paragraph (c)(4), the owner or operator has completed an inflow design flood control system plan when the plan has been placed in the facility's operating record as required by § 257.105(g)(4).

(5) The owner or operator must obtain a certification from a qualified professional engineer stating that the initial and periodic inflow design flood control system plans meet the requirements of this section.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(g), the notification requirements specified in § 257.106(g), and the internet requirements specified in § 257.107(g).

**§ 257.83 Inspection requirements for CCR surface impoundments.**

(a) *Inspections by a qualified person.* (1) All CCR surface impoundments and any lateral expansion of a CCR surface impoundment must be examined by a qualified person as follows:

(i) At intervals not exceeding seven days, inspect for any appearances of actual or potential structural weakness and other conditions which are disrupting or have the potential to disrupt the operation or safety of the CCR unit;

(ii) At intervals not exceeding seven days, inspect the discharge of all outlets of hydraulic structures which pass underneath the base of the surface impoundment or through the dike of the CCR unit for abnormal discoloration, flow or discharge of debris or sediment; and

(iii) At intervals not exceeding 30 days, monitor all CCR unit instrumentation.

(iv) The results of the inspection by a qualified person must be recorded in the facility's operating record as required by § 257.105(g)(5).

(2) *Timeframes for inspections by a qualified person*—(i) *Existing CCR surface impoundments.* The owner or operator of the CCR unit must initiate the inspections required under paragraph (a) of this section no later than October 19, 2015.

(ii) *New CCR surface impoundments and any lateral expansion of a CCR surface impoundment.* The owner or operator of the CCR unit must initiate the inspections required under paragraph (a) of this section upon initial receipt of CCR by the CCR unit.

(b) Annual i*nspections by a qualified professional engineer.* (1) If the existing or new CCR surface impoundment or any lateral expansion of the CCR surface impoundment is subject to the periodic structural stability assessment requirements under § 257.73(d) or § 257.74(d), the CCR unit must additionally be inspected on a periodic basis by a qualified professional engineer to ensure that the design, construction, operation, and maintenance of the CCR unit is consistent with recognized and generally accepted good engineering standards. The inspection must, at a minimum, include:

(i) A review of available information regarding the status and condition of the CCR unit, including, but not limited to, files available in the operating record (*e.g.,* CCR unit design and construction information required by §§ 257.73(c)(1) and 257.74(c)(1), previous periodic structural stability assessments required under §§ 257.73(d) and 257.74(d), the results of inspections by a qualified person, and results of previous annual inspections);

(ii) A visual inspection of the CCR unit to identify signs of distress or malfunction of the CCR unit and appurtenant structures; and

(iii) A visual inspection of any hydraulic structures underlying the base of the CCR unit or passing through the dike of the CCR unit for structural integrity and continued safe and reliable operation.

(2) *Inspection report.* The qualified professional engineer must prepare a report following each inspection that addresses the following:

(i) Any changes in geometry of the impounding structure since the previous annual inspection;

(ii) The location and type of existing instrumentation and the maximum recorded readings of each instrument since the previous annual inspection;

(iii) The approximate minimum, maximum, and present depth and elevation of the impounded water and CCR since the previous annual inspection;

(iv) The storage capacity of the impounding structure at the time of the inspection;

(v) The approximate volume of the impounded water and CCR at the time of the inspection;

(vi) Any appearances of an actual or potential structural weakness of the CCR unit, in addition to any existing conditions that are disrupting or have the potential to disrupt the operation and safety of the CCR unit and appurtenant structures; and

(vii) Any other change(s) which may have affected the stability or operation of the impounding structure since the previous annual inspection.

(3) *Timeframes for conducting the initial inspection*—(i) *Existing CCR surface impoundments.* The owner or operator of the CCR unit must complete the initial inspection required by paragraphs (b)(1) and (2) of this section no later than January 18, 2016.

(ii) *New CCR surface impoundments and any lateral expansion of a CCR surface impoundment.* The owner or operator of the CCR unit must complete the initial annual inspection required by paragraphs (b)(1) and (2) of this section is completed no later than 14 months

following the date of initial receipt of CCR in the CCR unit.

(4) *Frequency of inspections.* (i) Except as provided for in paragraph (b)(4)(ii) of this section, the owner or operator of the CCR unit must conduct the inspection required by paragraphs (b)(1) and (2) of this section on an annual basis. The date of completing the initial inspection report is the basis for establishing the deadline to complete the first subsequent inspection. Any required inspection may be conducted prior to the required deadline provided the owner or operator places the completed inspection report into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing subsequent inspection reports is based on the date of completing the previous inspection report. For purposes of this section, the owner or operator has completed an inspection when the inspection report has been placed in the facility's operating record as required by § 257.105(g)(6).

(ii) In any calendar year in which both the periodic inspection by a qualified professional engineer and the quinquennial (occurring every five years) structural stability assessment by a qualified professional engineer required by §§ 257.73(d) and 257.74(d) are required to be completed, the annual inspection is not required, provided the structural stability assessment is completed during the calendar year. If the annual inspection is not conducted in a year as provided by this paragraph (b)(4)(ii), the deadline for completing the next annual inspection is one year from the date of completing the quinquennial structural stability assessment.

(5) If a deficiency or release is identified during an inspection, the owner or operator must remedy the deficiency or release as soon as feasible and prepare documentation detailing the corrective measures taken.

(c) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(g), the notification requirements specified in § 257.106(g), and the internet requirements specified in § 257.107(g).

**§ 257.84 Inspection requirements for CCR landfills.**

(a) *Inspections by a qualified person.* (1) All CCR landfills and any lateral expansion of a CCR landfill must be examined by a qualified person as follows:

(i) At intervals not exceeding seven days, inspect for any appearances of actual or potential structural weakness and other conditions which are disrupting or have the potential to disrupt the operation or safety of the CCR unit; and

(ii) The results of the inspection by a qualified person must be recorded in the facility's operating record as required by § 257.105(g)(8).

(2) *Timeframes for inspections by a qualified person*—(i) *Existing CCR landfills.* The owner or operator of the CCR unit must initiate the inspections required under paragraph (a) of this section no later than October 19, 2015.

(ii) *New CCR landfills and any lateral expansion of a CCR landfill.* The owner or operator of the CCR unit must initiate the inspections required under paragraph (a) of this section upon initial receipt of CCR by the CCR unit.

(b) *Annual inspections by a qualified professional engineer.* (1) Existing and new CCR landfills and any lateral expansion of a CCR landfill must be inspected on a periodic basis by a qualified professional engineer to ensure that the design, construction, operation, and maintenance of the CCR unit is consistent with recognized and generally accepted good engineering standards. The inspection must, at a minimum, include:

(i) A review of available information regarding the status and condition of the CCR unit, including, but not limited to, files available in the operating record (*e.g.,* the results of inspections by a qualified person, and results of previous annual inspections); and

(ii) A visual inspection of the CCR unit to identify signs of distress or malfunction of the CCR unit.

(2) *Inspection report.* The qualified professional engineer must prepare a report following each inspection that addresses the following:

(i) Any changes in geometry of the structure since the previous annual inspection;

(ii) The approximate volume of CCR contained in the unit at the time of the inspection;

(iii) Any appearances of an actual or potential structural weakness of the CCR unit, in addition to any existing conditions that are disrupting or have the potential to disrupt the operation and safety of the CCR unit; and

(iv) Any other change(s) which may have affected the stability or operation of the CCR unit since the previous annual inspection.

(3) *Timeframes for conducting the initial inspection*—(i) *Existing CCR landfills.* The owner or operator of the CCR unit must complete the initial inspection required by paragraphs (b)(1) and (2) of this section no later than January 18, 2016.

(ii) *New CCR landfills and any lateral expansion of a CCR landfill.* The owner or operator of the CCR unit must complete the initial annual inspection required by paragraphs (b)(1) and (2) of this section no later than 14 months following the date of initial receipt of CCR in the CCR unit.

(4) *Frequency of inspections.* The owner or operator of the CCR unit must conduct the inspection required by paragraphs (b)(1) and (2) of this section on an annual basis. The date of completing the initial inspection report is the basis for establishing the deadline to complete the first subsequent inspection. Any required inspection may be conducted prior to the required deadline provided the owner or operator places the completed inspection report into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing subsequent inspection reports is based on the date of completing the previous inspection report. For purposes of this section, the owner or operator has completed an inspection when the inspection report has been placed in the facility's operating record as required by § 257.105(g)(9).

(5) If a deficiency or release is identified during an inspection, the owner or operator must remedy the deficiency or release as soon as feasible and prepare documentation detailing the corrective measures taken.

(c) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(g), the notification requirements specified in § 257.106(g), and the internet requirements specified in § 257.107(g).

## Groundwater Monitoring and Corrective Action

**§ 257.90 Applicability.**

(a) Except as provided for in § 257.100 for inactive CCR surface impoundments, all CCR landfills, CCR surface impoundments, and lateral expansions of CCR units are subject to the groundwater monitoring and corrective action requirements under §§ 257.90 through 257.98.

(b) *Initial timeframes*—(1) *Existing CCR landfills and existing CCR surface impoundments.* No later than October 17, 2017, the owner or operator of the CCR unit must be in compliance with the following groundwater monitoring requirements:

(i) Install the groundwater monitoring system as required by § 257.91;

(ii) Develop the groundwater sampling and analysis program to include selection of the statistical

procedures to be used for evaluating groundwater monitoring data as required by § 257.93;

(iii) Initiate the detection monitoring program to include obtaining a minimum of eight independent samples for each background and downgradient well as required by § 257.94(b); and

(iv) Begin evaluating the groundwater monitoring data for statistically significant increases over background levels for the constituents listed in appendix III of this part as required by § 257.94.

(2) *New CCR landfills, new CCR surface impoundments, and all lateral expansions of CCR units.* Prior to initial receipt of CCR by the CCR unit, the owner or operator must be in compliance with the groundwater monitoring requirements specified in paragraph (b)(1)(i) and (ii) of this section. In addition, the owner or operator of the CCR unit must initiate the detection monitoring program to include obtaining a minimum of eight independent samples for each background well as required by § 257.94(b).

(c) Once a groundwater monitoring system and groundwater monitoring program has been established at the CCR unit as required by this subpart, the owner or operator must conduct groundwater monitoring and, if necessary, corrective action throughout the active life and post-closure care period of the CCR unit.

(d) In the event of a release from a CCR unit, the owner or operator must immediately take all necessary measures to control the source(s) of releases so as to reduce or eliminate, to the maximum extent feasible, further releases of contaminants into the environment. The owner or operator of the CCR unit must comply with all applicable requirements in §§ 257.96, 257.97, and 257.98.

(e) *Annual groundwater monitoring and corrective action report.* For existing CCR landfills and existing CCR surface impoundments, no later than January 31, 2018, and annually thereafter, the owner or operator must prepare an annual groundwater monitoring and corrective action report. For new CCR landfills, new CCR surface impoundments, and all lateral expansions of CCR units, the owner or operator must prepare the initial annual groundwater monitoring and corrective action report no later than January 31 of the year following the calendar year a groundwater monitoring system has been established for such CCR unit as required by this subpart, and annually thereafter. For the preceding calendar year, the annual report must document the status of the groundwater monitoring and corrective action program for the CCR unit, summarize key actions completed, describe any problems encountered, discuss actions to resolve the problems, and project key activities for the upcoming year. For purposes of this section, the owner or operator has prepared the annual report when the report is placed in the facility's operating record as required by § 257.105(h)(1). At a minimum, the annual groundwater monitoring and corrective action report must contain the following information, to the extent available:

(1) A map, aerial image, or diagram showing the CCR unit and all background (or upgradient) and downgradient monitoring wells, to include the well identification numbers, that are part of the groundwater monitoring program for the CCR unit;

(2) Identification of any monitoring wells that were installed or decommissioned during the preceding year, along with a narrative description of why those actions were taken;

(3) In addition to all the monitoring data obtained under §§ 257.90 through 257.98, a summary including the number of groundwater samples that were collected for analysis for each background and downgradient well, the dates the samples were collected, and whether the sample was required by the detection monitoring or assessment monitoring programs;

(4) A narrative discussion of any transition between monitoring programs (*e.g.,* the date and circumstances for transitioning from detection monitoring to assessment monitoring in addition to identifying the constituent(s) detected at a statistically significant increase over background levels); and

(5) Other information required to be included in the annual report as specified in §§ 257.90 through 257.98.

(f) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h).

**§ 257.91 Groundwater monitoring systems.**

(a) *Performance standard.* The owner or operator of a CCR unit must install a groundwater monitoring system that consists of a sufficient number of wells, installed at appropriate locations and depths, to yield groundwater samples from the uppermost aquifer that:

(1) Accurately represent the quality of background groundwater that has not been affected by leakage from a CCR unit. A determination of background quality may include sampling of wells that are not hydraulically upgradient of the CCR management area where:

(i) Hydrogeologic conditions do not allow the owner or operator of the CCR unit to determine what wells are hydraulically upgradient; or

(ii) Sampling at other wells will provide an indication of background groundwater quality that is as representative or more representative than that provided by the upgradient wells; and

(2) Accurately represent the quality of groundwater passing the waste boundary of the CCR unit. The downgradient monitoring system must be installed at the waste boundary that ensures detection of groundwater contamination in the uppermost aquifer. All potential contaminant pathways must be monitored.

(b) The number, spacing, and depths of monitoring systems shall be determined based upon site-specific technical information that must include thorough characterization of:

(1) Aquifer thickness, groundwater flow rate, groundwater flow direction including seasonal and temporal fluctuations in groundwater flow; and

(2) Saturated and unsaturated geologic units and fill materials overlying the uppermost aquifer, materials comprising the uppermost aquifer, and materials comprising the confining unit defining the lower boundary of the uppermost aquifer, including, but not limited to, thicknesses, stratigraphy, lithology, hydraulic conductivities, porosities and effective porosities.

(c) The groundwater monitoring system must include the minimum number of monitoring wells necessary to meet the performance standards specified in paragraph (a) of this section, based on the site-specific information specified in paragraph (b) of this section. The groundwater monitoring system must contain:

(1) A minimum of one upgradient and three downgradient monitoring wells; and

(2) Additional monitoring wells as necessary to accurately represent the quality of background groundwater that has not been affected by leakage from the CCR unit and the quality of groundwater passing the waste boundary of the CCR unit.

(d) The owner or operator of multiple CCR units may install a multiunit groundwater monitoring system instead of separate groundwater monitoring systems for each CCR unit.

(1) The multiunit groundwater monitoring system must be equally as capable of detecting monitored constituents at the waste boundary of

the CCR unit as the individual groundwater monitoring system specified in paragraphs (a) through (c) of this section for each CCR unit based on the following factors:

(i) Number, spacing, and orientation of each CCR unit;

(ii) Hydrogeologic setting;

(iii) Site history; and

(iv) Engineering design of the CCR unit.

(2) If the owner or operator elects to install a multiunit groundwater monitoring system, and if the multiunit system includes at least one existing unlined CCR surface impoundment as determined by § 257.71(a), and if at any time after October 19, 2015 the owner or operator determines in any sampling event that the concentrations of one or more constituents listed in appendix IV to this part are detected at statistically significant levels above the groundwater protection standard established under § 257.95(h) for the multiunit system, then all unlined CCR surface impoundments comprising the multiunit groundwater monitoring system are subject to the closure requirements under § 257.101(a) to retrofit or close.

(e) Monitoring wells must be cased in a manner that maintains the integrity of the monitoring well borehole. This casing must be screened or perforated and packed with gravel or sand, where necessary, to enable collection of groundwater samples. The annular space (*i.e.,* the space between the borehole and well casing) above the sampling depth must be sealed to prevent contamination of samples and the groundwater.

(1) The owner or operator of the CCR unit must document and include in the operating record the design, installation, development, and decommissioning of any monitoring wells, piezometers and other measurement, sampling, and analytical devices. The qualified professional engineer must be given access to this documentation when completing the groundwater monitoring system certification required under paragraph (f) of this section.

(2) The monitoring wells, piezometers, and other measurement, sampling, and analytical devices must be operated and maintained so that they perform to the design specifications throughout the life of the monitoring program.

(f) The owner or operator must obtain a certification from a qualified professional engineer stating that the groundwater monitoring system has been designed and constructed to meet the requirements of this section. If the groundwater monitoring system includes the minimum number of monitoring wells specified in paragraph (c)(1) of this section, the certification must document the basis supporting this determination.

(g) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h).

**§ 257.92 [Reserved]**

**§ 257.93 Groundwater sampling and analysis requirements.**

(a) The groundwater monitoring program must include consistent sampling and analysis procedures that are designed to ensure monitoring results that provide an accurate representation of groundwater quality at the background and downgradient wells required by § 257.91. The owner or operator of the CCR unit must develop a sampling and analysis program that includes procedures and techniques for:

(1) Sample collection;

(2) Sample preservation and shipment;

(3) Analytical procedures;

(4) Chain of custody control; and

(5) Quality assurance and quality control.

(b) The groundwater monitoring program must include sampling and analytical methods that are appropriate for groundwater sampling and that accurately measure hazardous constituents and other monitoring parameters in groundwater samples. For purposes of §§ 257.90 through 257.98, the term *constituent* refers to both hazardous constituents and other monitoring parameters listed in either appendix III or IV of this part.

(c) Groundwater elevations must be measured in each well immediately prior to purging, each time groundwater is sampled. The owner or operator of the CCR unit must determine the rate and direction of groundwater flow each time groundwater is sampled. Groundwater elevations in wells which monitor the same CCR management area must be measured within a period of time short enough to avoid temporal variations in groundwater flow which could preclude accurate determination of groundwater flow rate and direction.

(d) The owner or operator of the CCR unit must establish background groundwater quality in a hydraulically upgradient or background well(s) for each of the constituents required in the particular groundwater monitoring program that applies to the CCR unit as determined under § 257.94(a) or § 257.95(a). Background groundwater quality may be established at wells that are not located hydraulically upgradient from the CCR unit if it meets the requirements of § 257.91(a)(1).

(e) The number of samples collected when conducting detection monitoring and assessment monitoring (for both downgradient and background wells) must be consistent with the statistical procedures chosen under paragraph (f) of this section and the performance standards under paragraph (g) of this section. The sampling procedures shall be those specified under § 257.94(b) through (d) for detection monitoring, § 257.95(b) through (d) for assessment monitoring, and § 257.96(b) for corrective action.

(f) The owner or operator of the CCR unit must select one of the statistical methods specified in paragraphs (f)(1) through (5) of this section to be used in evaluating groundwater monitoring data for each specified constituent. The statistical test chosen shall be conducted separately for each constituent in each monitoring well.

(1) A parametric analysis of variance followed by multiple comparison procedures to identify statistically significant evidence of contamination. The method must include estimation and testing of the contrasts between each compliance well's mean and the background mean levels for each constituent.

(2) An analysis of variance based on ranks followed by multiple comparison procedures to identify statistically significant evidence of contamination. The method must include estimation and testing of the contrasts between each compliance well's median and the background median levels for each constituent.

(3) A tolerance or prediction interval procedure, in which an interval for each constituent is established from the distribution of the background data and the level of each constituent in each compliance well is compared to the upper tolerance or prediction limit.

(4) A control chart approach that gives control limits for each constituent.

(5) Another statistical test method that meets the performance standards of paragraph (g) of this section.

(6) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the selected statistical method is appropriate for evaluating the groundwater monitoring data for the CCR management area. The certification must include a narrative description of the statistical method selected to evaluate the groundwater monitoring data.

(g) Any statistical method chosen under paragraph (f) of this section shall comply with the following performance standards, as appropriate, based on the statistical test method used:

(1) The statistical method used to evaluate groundwater monitoring data shall be appropriate for the distribution of constituents. Normal distributions of data values shall use parametric methods. Non-normal distributions shall use non-parametric methods. If the distribution of the constituents is shown by the owner or operator of the CCR unit to be inappropriate for a normal theory test, then the data must be transformed or a distribution-free (non-parametric) theory test must be used. If the distributions for the constituents differ, more than one statistical method may be needed.

(2) If an individual well comparison procedure is used to compare an individual compliance well constituent concentration with background constituent concentrations or a groundwater protection standard, the test shall be done at a Type I error level no less than 0.01 for each testing period. If a multiple comparison procedure is used, the Type I experiment wise error rate for each testing period shall be no less than 0.05; however, the Type I error of no less than 0.01 for individual well comparisons must be maintained. This performance standard does not apply to tolerance intervals, prediction intervals, or control charts.

(3) If a control chart approach is used to evaluate groundwater monitoring data, the specific type of control chart and its associated parameter values shall be such that this approach is at least as effective as any other approach in this section for evaluating groundwater data. The parameter values shall be determined after considering the number of samples in the background data base, the data distribution, and the range of the concentration values for each constituent of concern.

(4) If a tolerance interval or a predictional interval is used to evaluate groundwater monitoring data, the levels of confidence and, for tolerance intervals, the percentage of the population that the interval must contain, shall be such that this approach is at least as effective as any other approach in this section for evaluating groundwater data. These parameters shall be determined after considering the number of samples in the background data base, the data distribution, and the range of the concentration values for each constituent of concern.

(5) The statistical method must account for data below the limit of detection with one or more statistical procedures that shall at least as effective as any other approach in this section for evaluating groundwater data. Any practical quantitation limit that is used in the statistical method shall be the lowest concentration level that can be reliably achieved within specified limits of precision and accuracy during routine laboratory operating conditions that are available to the facility.

(6) If necessary, the statistical method must include procedures to control or correct for seasonal and spatial variability as well as temporal correlation in the data.

(h) The owner or operator of the CCR unit must determine whether or not there is a statistically significant increase over background values for each constituent required in the particular groundwater monitoring program that applies to the CCR unit, as determined under § 257.94(a) or § 257.95(a).

(1) In determining whether a statistically significant increase has occurred, the owner or operator must compare the groundwater quality of each constituent at each monitoring well designated pursuant to § 257.91(a)(2) or (d)(1) to the background value of that constituent, according to the statistical procedures and performance standards specified under paragraphs (f) and (g) of this section.

(2) Within 90 days after completing sampling and analysis, the owner or operator must determine whether there has been a statistically significant increase over background for any constituent at each monitoring well.

(i) The owner or operator must measure "total recoverable metals" concentrations in measuring groundwater quality. Measurement of total recoverable metals captures both the particulate fraction and dissolved fraction of metals in natural waters. Groundwater samples shall not be field-filtered prior to analysis.

(j) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the Internet requirements specified in § 257.107(h).

**§ 257.94 Detection monitoring program.**

(a) The owner or operator of a CCR unit must conduct detection monitoring at all groundwater monitoring wells consistent with this section. At a minimum, a detection monitoring program must include groundwater monitoring for all constituents listed in appendix III to this part.

(b) Except as provided in paragraph (d) of this section, the monitoring frequency for the constituents listed in appendix III to this part shall be at least semiannual during the active life of the CCR unit and the post-closure period. For existing CCR landfills and existing CCR surface impoundments, a minimum of eight independent samples from each background and downgradient well must be collected and analyzed for the constituents listed in appendix III and IV to this part no later than October 17, 2017. For new CCR landfills, new CCR surface impoundments, and all lateral expansions of CCR units, a minimum of eight independent samples for each background well must be collected and analyzed for the constituents listed in appendices III and IV to this part during the first six months of sampling.

(c) The number of samples collected and analyzed for each background well and downgradient well during subsequent semiannual sampling events must be consistent with § 257.93(e), and must account for any unique characteristics of the site, but must be at least one sample from each background and downgradient well.

(d) The owner or operator of a CCR unit may demonstrate the need for an alternative monitoring frequency for repeated sampling and analysis for constituents listed in appendix III to this part during the active life and the post-closure care period based on the availability of groundwater. If there is not adequate groundwater flow to sample wells semiannually, the alternative frequency shall be no less than annual. The need to vary monitoring frequency must be evaluated on a site-specific basis. The demonstration must be supported by, at a minimum, the information specified in paragraphs (d)(1) and (2) of this section.

(1) Information documenting that the need for less frequent sampling. The alternative frequency must be based on consideration of the following factors:

(i) Lithology of the aquifer and unsaturated zone;

(ii) Hydraulic conductivity of the aquifer and unsaturated zone; and

(iii) Groundwater flow rates.

(2) Information documenting that the alternative frequency will be no less effective in ensuring that any leakage from the CCR unit will be discovered within a timeframe that will not materially delay establishment of an assessment monitoring program.

(3) The owner or operator must obtain a certification from a qualified

professional engineer stating that the demonstration for an alternative groundwater sampling and analysis frequency meets the requirements of this section. The owner or operator must include the demonstration providing the basis for the alternative monitoring frequency and the certification by a qualified professional engineer in the annual groundwater monitoring and corrective action report required by § 257.90(e).

(e) If the owner or operator of the CCR unit determines, pursuant to § 257.93(h) that there is a statistically significant increase over background levels for one or more of the constituents listed in appendix III to this part at any monitoring well at the waste boundary specified under § 257.91(a)(2), the owner or operator must:

(1) Except as provided for in paragraph (e)(2) of this section, within 90 days of detecting a statistically significant increase over background levels for any constituent, establish an assessment monitoring program meeting the requirements of § 257.95.

(2) The owner or operator may demonstrate that a source other than the CCR unit caused the statistically significant increase over background levels for a constituent or that the statistically significant increase resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality. The owner or operator must complete the written demonstration within 90 days of detecting a statistically significant increase over background levels to include obtaining a certification from a qualified professional engineer verifying the accuracy of the information in the report. If a successful demonstration is completed within the 90-day period, the owner or operator of the CCR unit may continue with a detection monitoring program under this section. If a successful demonstration is not completed within the 90-day period, the owner or operator of the CCR unit must initiate an assessment monitoring program as required under § 257.95. The owner or operator must also include the demonstration in the annual groundwater monitoring and corrective action report required by § 257.90(e), in addition to the certification by a qualified professional engineer.

(3) The owner or operator of a CCR unit must prepare a notification stating that an assessment monitoring program has been established. The owner or operator has completed the notification when the notification is placed in the facility's operating record as required by § 257.105(h)(5).

(f) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the Internet requirements specified in § 257.107(h).

**§ 257.95 Assessment monitoring program.**

(a) Assessment monitoring is required whenever a statistically significant increase over background levels has been detected for one or more of the constituents listed in appendix III to this part.

(b) Within 90 days of triggering an assessment monitoring program, and annually thereafter, the owner or operator of the CCR unit must sample and analyze the groundwater for all constituents listed in appendix IV to this part. The number of samples collected and analyzed for each well during each sampling event must be consistent with § 257.93(e), and must account for any unique characteristics of the site, but must be at least one sample from each well.

(c) The owner or operator of a CCR unit may demonstrate the need for an alternative monitoring frequency for repeated sampling and analysis for constituents listed in appendix IV to this part during the active life and the post-closure care period based on the availability of groundwater. If there is not adequate groundwater flow to sample wells semiannually, the alternative frequency shall be no less than annual. The need to vary monitoring frequency must be evaluated on a site-specific basis. The demonstration must be supported by, at a minimum, the information specified in paragraphs (c)(1) and (2) of this section.

(1) Information documenting that the need for less frequent sampling. The alternative frequency must be based on consideration of the following factors:

(i) Lithology of the aquifer and unsaturated zone;

(ii) Hydraulic conductivity of the aquifer and unsaturated zone; and

(iii) Groundwater flow rates.

(2) Information documenting that the alternative frequency will be no less effective in ensuring that any leakage from the CCR unit will be discovered within a timeframe that will not materially delay the initiation of any necessary remediation measures.

(3) The owner or operator must obtain a certification from a qualified professional engineer stating that the demonstration for an alternative groundwater sampling and analysis frequency meets the requirements of this section. The owner or operator must include the demonstration providing the basis for the alternative monitoring frequency and the certification by a qualified professional engineer in the annual groundwater monitoring and corrective action report required by § 257.90(e).

(d) After obtaining the results from the initial and subsequent sampling events required in paragraph (b) of this section, the owner or operator must:

(1) Within 90 days of obtaining the results, and on at least a semiannual basis thereafter, resample all wells that were installed pursuant to the requirements of § 257.91, conduct analyses for all parameters in appendix III to this part and for those constituents in appendix IV to this part that are detected in response to paragraph (b) of this section, and record their concentrations in the facility operating record. The number of samples collected and analyzed for each background well and downgradient well during subsequent semiannual sampling events must be consistent with § 257.93(e), and must account for any unique characteristics of the site, but must be at least one sample from each background and downgradient well;

(2) Establish groundwater protection standards for all constituents detected pursuant to paragraph (b) or (d) of this section. The groundwater protection standards must be established in accordance with paragraph (h) of this section; and

(3) Include the recorded concentrations required by paragraph (d)(1) of this section, identify the background concentrations established under § 257.94(b), and identify the groundwater protection standards established under paragraph (d)(2) of this section in the annual groundwater monitoring and corrective action report required by § 257.90(e).

(e) If the concentrations of all constituents listed in appendices III and IV to this part are shown to be at or below background values, using the statistical procedures in § 257.93(g), for two consecutive sampling events, the owner or operator may return to detection monitoring of the CCR unit. The owner or operator must prepare a notification stating that detection monitoring is resuming for the CCR unit. The owner or operator has completed the notification when the notification is placed in the facility's operating record as required by § 257.105(h)(7).

(f) If the concentrations of any constituent in appendices III and IV to this part are above background values, but all concentrations are below the groundwater protection standard

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established under paragraph (h) of this section, using the statistical procedures in § 257.93(g), the owner or operator must continue assessment monitoring in accordance with this section.

(g) If one or more constituents in appendix IV to this part are detected at statistically significant levels above the groundwater protection standard established under paragraph (h) of this section in any sampling event, the owner or operator must prepare a notification identifying the constituents in appendix IV to this part that have exceeded the groundwater protection standard. The owner or operator has completed the notification when the notification is placed in the facility's operating record as required by § 257.105(h)(8). The owner or operator of the CCR unit also must:

(1) Characterize the nature and extent of the release and any relevant site conditions that may affect the remedy ultimately selected. The characterization must be sufficient to support a complete and accurate assessment of the corrective measures necessary to effectively clean up all releases from the CCR unit pursuant to § 257.96. Characterization of the release includes the following minimum measures:

(i) Install additional monitoring wells necessary to define the contaminant plume(s);

(ii) Collect data on the nature and estimated quantity of material released including specific information on the constituents listed in appendix IV of this part and the levels at which they are present in the material released;

(iii) Install at least one additional monitoring well at the facility boundary in the direction of contaminant migration and sample this well in accordance with paragraph (d)(1) of this section; and

(iv) Sample all wells in accordance with paragraph (d)(1) of this section to characterize the nature and extent of the release.

(2) Notify all persons who own the land or reside on the land that directly overlies any part of the plume of contamination if contaminants have migrated off-site if indicated by sampling of wells in accordance with paragraph (g)(1) of this section. The owner or operator has completed the notifications when they are placed in the facility's operating record as required by § 257.105(h)(8).

(3) Within 90 days of finding that any of the constituents listed in appendix IV to this part have been detected at a statistically significant level exceeding the groundwater protection standards the owner or operator must either:

(i) Initiate an assessment of corrective measures as required by § 257.96; or

(ii) Demonstrate that a source other than the CCR unit caused the contamination, or that the statistically significant increase resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality. Any such demonstration must be supported by a report that includes the factual or evidentiary basis for any conclusions and must be certified to be accurate by a qualified professional engineer. If a successful demonstration is made, the owner or operator must continue monitoring in accordance with the assessment monitoring program pursuant to this section, and may return to detection monitoring if the constituents in appendices III and IV to this part are at or below background as specified in paragraph (e) of this section. The owner or operator must also include the demonstration in the annual groundwater monitoring and corrective action report required by § 257.90(e), in addition to the certification by a qualified professional engineer.

(4) If a successful demonstration has not been made at the end of the 90 day period provided by paragraph (g)(3)(ii) of this section, the owner or operator of the CCR unit must initiate the assessment of corrective measures requirements under § 257.96.

(5) If an assessment of corrective measures is required under § 257.96 by either paragraph (g)(3)(i) or (g)(4) of this section, and if the CCR unit is an existing unlined CCR surface impoundment as determined by § 257.71(a), then the CCR unit is subject to the closure requirements under § 257.101(a) to retrofit or close. In addition, the owner or operator must prepare a notification stating that an assessment of corrective measures has been initiated.

(h) The owner or operator of the CCR unit must establish a groundwater protection standard for each constituent in appendix IV to this part detected in the groundwater. The groundwater protection standard shall be:

(1) For constituents for which a maximum contaminant level (MCL) has been established under §§ 141.62 and 141.66 of this title, the MCL for that constituent;

(2) For constituents for which an MCL has not been established, the background concentration for the constituent established from wells in accordance with § 257.91; or

(3) For constituents for which the background level is higher than the MCL identified under paragraph (h)(1) of this section, the background concentration.

(i) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the Internet requirements specified in § 257.107(h).

**§ 257.96 Assessment of corrective measures.**

(a) Within 90 days of finding that any constituent listed in appendix IV to this part has been detected at a statistically significant level exceeding the groundwater protection standard defined under § 257.95(h), or immediately upon detection of a release from a CCR unit, the owner or operator must initiate an assessment of corrective measures to prevent further releases, to remediate any releases and to restore affected area to original conditions. The assessment of corrective measures must be completed within 90 days, unless the owner or operator demonstrates the need for additional time to complete the assessment of corrective measures due to site-specific conditions or circumstances. The owner or operator must obtain a certification from a qualified professional engineer attesting that the demonstration is accurate. The 90-day deadline to complete the assessment of corrective measures may be extended for no longer than 60 days. The owner or operator must also include the demonstration in the annual groundwater monitoring and corrective action report required by § 257.90(e), in addition to the certification by a qualified professional engineer.

(b) The owner or operator of the CCR unit must continue to monitor groundwater in accordance with the assessment monitoring program as specified in § 257.95.

(c) The assessment under paragraph (a) of this section must include an analysis of the effectiveness of potential corrective measures in meeting all of the requirements and objectives of the remedy as described under § 257.97 addressing at least the following:

(1) The performance, reliability, ease of implementation, and potential impacts of appropriate potential remedies, including safety impacts, cross-media impacts, and control of exposure to any residual contamination;

(2) The time required to begin and complete the remedy;

(3) The institutional requirements, such as state or local permit requirements or other environmental or public health requirements that may substantially affect implementation of the remedy(s).

(d) The owner or operator must place the completed assessment of corrective measures in the facility's operating record. The assessment has been completed when it is placed in the facility's operating record as required by § 257.105(h)(10).

(e) The owner or operator must discuss the results of the corrective measures assessment at least 30 days prior to the selection of remedy, in a public meeting with interested and affected parties.

(f) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the Internet requirements specified in § 257.107(h).

**§ 257.97 Selection of remedy.**

(a) Based on the results of the corrective measures assessment conducted under § 257.96, the owner or operator must, as soon as feasible, select a remedy that, at a minimum, meets the standards listed in paragraph (b) of this section. This requirement applies to, not in place of, any applicable standards under the Occupational Safety and Health Act. The owner or operator must prepare a semiannual report describing the progress in selecting and designing the remedy. Upon selection of a remedy, the owner or operator must prepare a final report describing the selected remedy and how it meets the standards specified in paragraph (b) of this section. The owner or operator must obtain a certification from a qualified professional engineer that the remedy selected meets the requirements of this section. The report has been completed when it is placed in the operating record as required by § 257.105(h)(12).

(b) Remedies must:

(1) Be protective of human health and the environment;

(2) Attain the groundwater protection standard as specified pursuant to § 257.95(h);

(3) Control the source(s) of releases so as to reduce or eliminate, to the maximum extent feasible, further releases of constituents in appendix IV to this part into the environment;

(4) Remove from the environment as much of the contaminated material that was released from the CCR unit as is feasible, taking into account factors such as avoiding inappropriate disturbance of sensitive ecosystems;

(5) Comply with standards for management of wastes as specified in § 257.98(d).

(c) In selecting a remedy that meets the standards of paragraph (b) of this section, the owner or operator of the CCR unit shall consider the following evaluation factors:

(1) The long- and short-term effectiveness and protectiveness of the potential remedy(s), along with the degree of certainty that the remedy will prove successful based on consideration of the following:

(i) Magnitude of reduction of existing risks;

(ii) Magnitude of residual risks in terms of likelihood of further releases due to CCR remaining following implementation of a remedy;

(iii) The type and degree of long-term management required, including monitoring, operation, and maintenance;

(iv) Short-term risks that might be posed to the community or the environment during implementation of such a remedy, including potential threats to human health and the environment associated with excavation, transportation, and re-disposal of contaminant;

(v) Time until full protection is achieved;

(vi) Potential for exposure of humans and environmental receptors to remaining wastes, considering the potential threat to human health and the environment associated with excavation, transportation, re-disposal, or containment;

(vii) Long-term reliability of the engineering and institutional controls; and

(viii) Potential need for replacement of the remedy.

(2) The effectiveness of the remedy in controlling the source to reduce further releases based on consideration of the following factors:

(i) The extent to which containment practices will reduce further releases; and

(ii) The extent to which treatment technologies may be used.

(3) The ease or difficulty of implementing a potential remedy(s) based on consideration of the following types of factors:

(i) Degree of difficulty associated with constructing the technology;

(ii) Expected operational reliability of the technologies;

(iii) Need to coordinate with and obtain necessary approvals and permits from other agencies;

(iv) Availability of necessary equipment and specialists; and

(v) Available capacity and location of needed treatment, storage, and disposal services.

(4) The degree to which community concerns are addressed by a potential remedy(s).

(d) The owner or operator must specify as part of the selected remedy a schedule(s) for implementing and completing remedial activities. Such a schedule must require the completion of remedial activities within a reasonable period of time taking into consideration the factors set forth in paragraphs (d)(1) through (6) of this section. The owner or operator of the CCR unit must consider the following factors in determining the schedule of remedial activities:

(1) Extent and nature of contamination, as determined by the characterization required under § 257.95(g);

(2) Reasonable probabilities of remedial technologies in achieving compliance with the groundwater protection standards established under § 257.95(h) and other objectives of the remedy;

(3) Availability of treatment or disposal capacity for CCR managed during implementation of the remedy;

(4) Potential risks to human health and the environment from exposure to contamination prior to completion of the remedy;

(5) Resource value of the aquifer including:

(i) Current and future uses;

(ii) Proximity and withdrawal rate of users;

(iii) Groundwater quantity and quality;

(iv) The potential damage to wildlife, crops, vegetation, and physical structures caused by exposure to CCR constituents;

(v) The hydrogeologic characteristic of the facility and surrounding land; and

(vi) The availability of alternative water supplies; and

(6) Other relevant factors.

(e) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the Internet requirements specified in § 257.107(h).

**§ 257.98 Implementation of the corrective action program.**

(a) Within 90 days of selecting a remedy under § 257.97, the owner or operator must initiate remedial activities. Based on the schedule established under § 257.97(d) for implementation and completion of remedial activities the owner or operator must:

(1) Establish and implement a corrective action groundwater monitoring program that:

(i) At a minimum, meets the requirements of an assessment monitoring program under § 257.95;

(ii) Documents the effectiveness of the corrective action remedy; and

(iii) Demonstrates compliance with the groundwater protection standard pursuant to paragraph (c) of this section.

(2) Implement the corrective action remedy selected under § 257.97; and

(3) Take any interim measures necessary to reduce the contaminants leaching from the CCR unit, and/or potential exposures to human or ecological receptors. Interim measures must, to the greatest extent feasible, be consistent with the objectives of and contribute to the performance of any remedy that may be required pursuant to § 257.97. The following factors must be considered by an owner or operator in determining whether interim measures are necessary:

(i) Time required to develop and implement a final remedy;

(ii) Actual or potential exposure of nearby populations or environmental receptors to any of the constituents listed in appendix IV of this part;

(iii) Actual or potential contamination of drinking water supplies or sensitive ecosystems;

(iv) Further degradation of the groundwater that may occur if remedial action is not initiated expeditiously;

(v) Weather conditions that may cause any of the constituents listed in appendix IV to this part to migrate or be released;

(vi) Potential for exposure to any of the constituents listed in appendix IV to this part as a result of an accident or failure of a container or handling system; and

(vii) Other situations that may pose threats to human health and the environment.

(b) If an owner or operator of the CCR unit, determines, at any time, that compliance with the requirements of § 257.97(b) is not being achieved through the remedy selected, the owner or operator must implement other methods or techniques that could feasibly achieve compliance with the requirements.

(c) Remedies selected pursuant to § 257.97 shall be considered complete when:

(1) The owner or operator of the CCR unit demonstrates compliance with the groundwater protection standards established under § 257.95(h) has been achieved at all points within the plume of contamination that lie beyond the groundwater monitoring well system established under § 257.91.

(2) Compliance with the groundwater protection standards established under § 257.95(h) has been achieved by demonstrating that concentrations of constituents listed in appendix IV to this part have not exceeded the groundwater protection standard(s) for a period of three consecutive years using the statistical procedures and performance standards in § 257.93(f) and (g).

(3) All actions required to complete the remedy have been satisfied.

(d) All CCR that are managed pursuant to a remedy required under § 257.97, or an interim measure required under paragraph (a)(3) of this section, shall be managed in a manner that complies with all applicable RCRA requirements.

(e) Upon completion of the remedy, the owner or operator must prepare a notification stating that the remedy has been completed. The owner or operator must obtain a certification from a qualified professional engineer attesting that the remedy has been completed in compliance with the requirements of paragraph (c) of this section. The report has been completed when it is placed in the operating record as required by § 257.105(h)(13).

(f) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h).

## Closure and Post-Closure Care

### § 257.100 Inactive CCR surface impoundments.

(a) Except as provided by paragraph (b) of this section, inactive CCR surface impoundments are subject to all of the requirements of this subpart applicable to existing CCR surface impoundments.

(b) An owner or operator of an inactive CCR surface impoundment that completes closure of such CCR unit, and meets all of the requirements of either paragraphs (b)(1) through (4) of this section or paragraph (b)(5) of this section no later than April 17, 2018, is exempt from all other requirements of this subpart.

(1) *Closure by leaving CCR in place.* If the owner or operator of the inactive CCR surface impoundment elects to close the CCR surface impoundment by leaving CCR in place, the owner or operator must ensure that, at a minimum, the CCR unit is closed in a manner that will:

(i) Control, minimize or eliminate, to the maximum extent feasible, post-closure infiltration of liquids into the waste and releases of CCR, leachate, or contaminated run-off to the ground or surface waters or to the atmosphere;

(ii) Preclude the probability of future impoundment of water, sediment, or slurry;

(iii) Include measures that provide for major slope stability to prevent the sloughing or movement of the final cover system; and

(iv) Minimize the need for further maintenance of the CCR unit.

(2) The owner or operator of the inactive CCR surface impoundment must meet the requirements of paragraphs (b)(2)(i) and (ii) of this section prior to installing the final cover system required under paragraph (b)(3) of this section.

(i) Free liquids must be eliminated by removing liquid wastes or solidifying the remaining wastes and waste residues.

(ii) Remaining wastes must be stabilized sufficient to support the final cover system.

(3) The owner or operator must install a final cover system that is designed to minimize infiltration and erosion, and at a minimum, meets the requirements of paragraph (b)(3)(i) of this section, or the requirements of an alternative final cover system specified in paragraph (b)(3)(ii) of this section.

(i) The final cover system must be designed and constructed to meet the criteria specified in paragraphs (b)(3)(i)(A) through (D) of this section.

(A) The permeability of the final cover system must be less than or equal to the permeability of any bottom liner system or natural subsoils present, or a permeability no greater than $1 \times 10^{-5}$ centimeters/second, whichever is less.

(B) The infiltration of liquids through the CCR unit must be minimized by the use of an infiltration layer that contains a minimum of 18 inches of earthen material.

(C) The erosion of the final cover system must be minimized by the use of an erosion layer that contains a minimum of six inches of earthen material that is capable of sustaining native plant growth.

(D) The disruption of the integrity of the final cover system must be minimized through a design that accommodates settling and subsidence.

(ii) The owner or operator may select an alternative final cover system design, provided the alternative final cover system is designed and constructed to meet the criteria in paragraphs (b)(3)(ii)(A) through (C) of this section.

(A) The design of the final cover system must include an infiltration layer that achieves an equivalent reduction in infiltration as the infiltration layer specified in paragraphs (b)(3)(i)(A) and (B) of this section.

(B) The design of the final cover system must include an erosion layer that provides equivalent protection from wind or water erosion as the erosion layer specified in paragraph (b)(3)(i)(C) of this section.

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(C) The disruption of the integrity of the final cover system must be minimized through a design that accommodates settling and subsidence.

(4) The owner or operator of the CCR surface impoundment must obtain a written certification from a qualified professional engineer stating that the design of the final cover system meets either the requirements of paragraphs (b)(3)(i) or (ii) of this section.

(5) *Closure through removal of CCR.* The owner or operator may alternatively elect to close an inactive CCR surface impoundment by removing and decontaminating all areas affected by releases from the CCR surface impoundment. CCR removal and decontamination of the CCR surface impoundment are complete when all CCR in the inactive CCR surface impoundment is removed, including the bottom liner of the CCR unit.

(6) The owner or operator of the CCR surface impoundment must obtain a written certification from a qualified professional engineer that closure of the CCR surface impoundment under either paragraphs (b)(1) through (4) or (b)(5) of this section is technically feasible within the timeframe in paragraph (b) of this section.

(7) If the owner or operator of the CCR surface impoundment fails to complete closure of the inactive CCR surface impoundment within the timeframe in paragraph (b) of this section, the CCR unit must comply with all of the requirements applicable to existing CCR surface impoundments under this subpart.

(c) *Required notices and progress reports.* An owner or operator of an inactive CCR surface impoundment that closes in accordance with paragraph (b) of this section must complete the notices and progress reports specified in paragraphs (c)(1) through (3) of this section.

(1) No later than December 17, 2015, the owner or operator must prepare and place in the facility's operating record a notification of intent to initiate closure of the CCR surface impoundment. The notification must state that the CCR surface impoundment is an inactive CCR surface impoundment closing under the requirements of paragraph (b) of this section. The notification must also include a narrative description of how the CCR surface impoundment will be closed, a schedule for completing closure activities, and the required certifications under paragraphs (b)(4) and (6) of this section, if applicable.

(2) The owner or operator must prepare periodic progress reports summarizing the progress of closure implementation, including a description of the actions completed to date, any problems encountered and a description of the actions taken to resolve the problems, and projected closure activities for the upcoming year. The annual progress reports must be completed according to the following schedule:

(i) The first annual progress report must be prepared no later than 13 months after completing the notification of intent to initiate closure required by paragraph (c)(1) of this section.

(ii) The second annual progress report must be prepared no later than 12 months after completing the first progress report required by paragraph (c)(2)(i) of this section.

(iii) The owner or operator has completed the progress reports specified in paragraph (c)(2) of this section when the reports are placed in the facility's operating record as required by § 257.105(i)(2).

(3) The owner or operator must prepare and place in the facility's operating record a notification of completion of closure of the CCR surface impoundment. The notification must be submitted within 60 days of completing closure of the CCR surface impoundment and must include a written certification from a qualified professional engineer stating that the CCR surface impoundment was closed in accordance with the requirements of either paragraph (b)(1) through (4) or (b)(5) of this section.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(i), the notification requirements specified in § 257.106(i), and the internet requirements specified in § 257.107(i).

**§ 257.101 Closure or retrofit of CCR units.**

(a) The owner or operator of an existing unlined CCR surface impoundment, as determined under § 257.71(a), is subject to the requirements of paragraph (a)(1) of this section.

(1) Except as provided by paragraph (a)(3) of this section, if at any time after October 19, 2015 an owner or operator of an existing unlined CCR surface impoundment determines in any sampling event that the concentrations of one or more constituents listed in appendix IV to this part are detected at statistically significant levels above the groundwater protection standard established under § 257.95(h) for such CCR unit, within six months of making such determination, the owner or operator of the existing unlined CCR surface impoundment must cease placing CCR and non-CCR wastestreams into such CCR surface impoundment and either retrofit or close the CCR unit in accordance with the requirements of § 257.102.

(2) An owner or operator of an existing unlined CCR surface impoundment that closes in accordance with paragraph (a)(1) of this section must include a statement in the notification required under § 257.102(g) or (k)(5) that the CCR surface impoundment is closing or retrofitting under the requirements of paragraph (a)(1) of this section.

(3) The timeframe specified in paragraph (a)(1) of this section does not apply if the owner or operator complies with the alternative closure procedures specified in § 257.103.

(4) At any time after the initiation of closure under paragraph (a)(1) of this section, the owner or operator may cease closure activities and initiate a retrofit of the CCR unit in accordance with the requirements of § 257.102(k).

(b) The owner or operator of an existing CCR surface impoundment is subject to the requirements of paragraph (b)(1) of this section.

(1) Except as provided by paragraph (b)(4) of this section, within six months of determining that an existing CCR surface impoundment has not demonstrated compliance with any location standard specified in §§ 257.60(a), 257.61(a), 257.62(a), 257.63(a), and 257.64(a), the owner or operator of the CCR surface impoundment must cease placing CCR and non-CCR wastestreams into such CCR unit and close the CCR unit in accordance with the requirements of § 257.102.

(2) Within six months of either failing to complete the initial or any subsequent periodic safety factor assessment required by § 257.73(e) by the deadlines specified in § 257.73(f)(1) through (3) or failing to document that the calculated factors of safety for the existing CCR surface impoundment achieve the minimum safety factors specified in § 257.73(e)(1)(i) through (iv), the owner or operator of the CCR surface impoundment must cease placing CCR and non-CCR wastestreams into such CCR unit and close the CCR unit in accordance with the requirements of § 257.102.

(3) An owner or operator of an existing CCR surface impoundment that closes in accordance with paragraphs (b)(1) or (2) of this section must include a statement in the notification required under § 257.102(g) that the CCR surface impoundment is closing under the requirements of paragraphs (b)(1) or (2) of this section.

(4) The timeframe specified in paragraph (b)(1) of this section does not apply if the owner or operator complies with the alternative closure procedures specified in § 257.103.

(c) The owner or operator of a new CCR surface impoundment is subject to the requirements of paragraph (c)(1) of this section.

(1) Within six months of either failing to complete the initial or any subsequent periodic safety factor assessment required by § 257.74(e) by the deadlines specified in § 257.74(f)(1) through (3) or failing to document that the calculated factors of safety for the new CCR surface impoundment achieve the minimum safety factors specified in § 257.74(e)(1)(i) through (v), the owner or operator of the CCR surface impoundment must cease placing CCR and non-CCR wastestreams into such CCR unit and close the CCR unit in accordance with the requirements of § 257.102.

(2) An owner or operator of an new CCR surface impoundment that closes in accordance with paragraph (c)(1) of this section must include a statement in the notification required under § 257.102(g) that the CCR surface impoundment is closing under the requirements of paragraph (c)(1) of this section.

(d) The owner or operator of an existing CCR landfill is subject to the requirements of paragraph (d)(1) of this section.

(1) Except as provided by paragraph (d)(3) of this section, within six months of determining that an existing CCR landfill has not demonstrated compliance with the location restriction for unstable areas specified in § 257.64(a), the owner or operator of the CCR unit must cease placing CCR and non-CCR waste streams into such CCR landfill and close the CCR unit in accordance with the requirements of § 257.102.

(2) An owner or operator of an existing CCR landfill that closes in accordance with paragraph (d)(1) of this section must include a statement in the notification required under § 257.102(g) that the CCR landfill is closing under the requirements of paragraph (d)(1) of this section.

(3) The timeframe specified in paragraph (d)(1) of this section does not apply if the owner or operator complies with the alternative closure procedures specified in § 257.103.

**§ 257.102 Criteria for conducting the closure or retrofit of CCR units.**

(a) Closure of a CCR landfill, CCR surface impoundment, or any lateral expansion of a CCR unit must be completed either by leaving the CCR in place and installing a final cover system or through removal of the CCR and decontamination of the CCR unit, as described in paragraphs (b) through (j) of this section. Retrofit of a CCR surface impoundment must be completed in accordance with the requirements in paragraph (k) of this section.

(b) *Written closure plan*—(1) *Content of the plan.* The owner or operator of a CCR unit must prepare a written closure plan that describes the steps necessary to close the CCR unit at any point during the active life of the CCR unit consistent with recognized and generally accepted good engineering practices. The written closure plan must include, at a minimum, the information specified in paragraphs (b)(1)(i) through (vi) of this section.

(i) A narrative description of how the CCR unit will be closed in accordance with this section.

(ii) If closure of the CCR unit will be accomplished through removal of CCR from the CCR unit, a description of the procedures to remove the CCR and decontaminate the CCR unit in accordance with paragraph (c) of this section.

(iii) If closure of the CCR unit will be accomplished by leaving CCR in place, a description of the final cover system, designed in accordance with paragraph (d) of this section, and the methods and procedures to be used to install the final cover. The closure plan must also discuss how the final cover system will achieve the performance standards specified in paragraph (d) of this section.

(iv) An estimate of the maximum inventory of CCR ever on-site over the active life of the CCR unit.

(v) An estimate of the largest area of the CCR unit ever requiring a final cover as required by paragraph (d) of this section at any time during the CCR unit's active life.

(vi) A schedule for completing all activities necessary to satisfy the closure criteria in this section, including an estimate of the year in which all closure activities for the CCR unit will be completed. The schedule should provide sufficient information to describe the sequential steps that will be taken to close the CCR unit, including identification of major milestones such as coordinating with and obtaining necessary approvals and permits from other agencies, the dewatering and stabilization phases of CCR surface impoundment closure, or installation of the final cover system, and the estimated timeframes to complete each step or phase of CCR unit closure. When preparing the written closure plan, if the owner or operator of a CCR unit estimates that the time required to complete closure will exceed the timeframes specified in paragraph (f)(1) of this section, the written closure plan must include the site-specific information, factors and considerations that would support any time extension sought under paragraph (f)(2) of this section.

(2) *Timeframes for preparing the initial written closure plan*—(i) *Existing CCR landfills and existing CCR surface impoundments.* No later than October 17, 2016, the owner or operator of the CCR unit must prepare an initial written closure plan consistent with the requirements specified in paragraph (b)(1) of this section.

(ii) *New CCR landfills and new CCR surface impoundments, and any lateral expansion of a CCR unit.* No later than the date of the initial receipt of CCR in the CCR unit, the owner or operator must prepare an initial written closure plan consistent with the requirements specified in paragraph (b)(1) of this section.

(iii) The owner or operator has completed the written closure plan when the plan, including the certification required by paragraph (b)(4) of this section, has been placed in the facility's operating record as required by § 257.105(i)(4).

(3) *Amendment of a written closure plan.* (i) The owner or operator may amend the initial or any subsequent written closure plan developed pursuant to paragraph (b)(1) of this section at any time.

(ii) The owner or operator must amend the written closure plan whenever:

(A) There is a change in the operation of the CCR unit that would substantially affect the written closure plan in effect; or

(B) Before or after closure activities have commenced, unanticipated events necessitate a revision of the written closure plan.

(iii) The owner or operator must amend the closure plan at least 60 days prior to a planned change in the operation of the facility or CCR unit, or no later than 60 days after an unanticipated event requires the need to revise an existing written closure plan. If a written closure plan is revised after closure activities have commenced for a CCR unit, the owner or operator must amend the current closure plan no later than 30 days following the triggering event.

(4) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer that the initial and any amendment of

the written closure plan meets the requirements of this section.

(c) *Closure by removal of CCR.* An owner or operator may elect to close a CCR unit by removing and decontaminating all areas affected by releases from the CCR unit. CCR removal and decontamination of the CCR unit are complete when constituent concentrations throughout the CCR unit and any areas affected by releases from the CCR unit have been removed and groundwater monitoring concentrations do not exceed the groundwater protection standard established pursuant to § 257.95(h) for constituents listed in appendix IV to this part.

(d) *Closure performance standard when leaving CCR in place*—(1) The owner or operator of a CCR unit must ensure that, at a minimum, the CCR unit is closed in a manner that will:

(i) Control, minimize or eliminate, to the maximum extent feasible, post-closure infiltration of liquids into the waste and releases of CCR, leachate, or contaminated run-off to the ground or surface waters or to the atmosphere;

(ii) Preclude the probability of future impoundment of water, sediment, or slurry;

(iii) Include measures that provide for major slope stability to prevent the sloughing or movement of the final cover system during the closure and post-closure care period;

(iv) Minimize the need for further maintenance of the CCR unit; and

(v) Be completed in the shortest amount of time consistent with recognized and generally accepted good engineering practices.

(2) *Drainage and stabilization of CCR surface impoundments.* The owner or operator of a CCR surface impoundment or any lateral expansion of a CCR surface impoundment must meet the requirements of paragraphs (d)(2)(i) and (ii) of this section prior to installing the final cover system required under paragraph (d)(3) of this section.

(i) Free liquids must be eliminated by removing liquid wastes or solidifying the remaining wastes and waste residues.

(ii) Remaining wastes must be stabilized sufficient to support the final cover system.

(3) *Final cover system.* If a CCR unit is closed by leaving CCR in place, the owner or operator must install a final cover system that is designed to minimize infiltration and erosion, and at a minimum, meets the requirements of paragraph (d)(3)(i) of this section, or the requirements of the alternative final cover system specified in paragraph (d)(3)(ii) of this section.

(i) The final cover system must be designed and constructed to meet the criteria in paragraphs (d)(3)(i)(A) through (D) of this section. The design of the final cover system must be included in the written closure plan required by paragraph (b) of this section.

(A) The permeability of the final cover system must be less than or equal to the permeability of any bottom liner system or natural subsoils present, or a permeability no greater than $1 \times 10^{-5}$ cm/sec, whichever is less.

(B) The infiltration of liquids through the closed CCR unit must be minimized by the use of an infiltration layer that contains a minimum of 18 inches of earthen material.

(C) The erosion of the final cover system must be minimized by the use of an erosion layer that contains a minimum of six inches of earthen material that is capable of sustaining native plant growth.

(D) The disruption of the integrity of the final cover system must be minimized through a design that accommodates settling and subsidence.

(ii) The owner or operator may select an alternative final cover system design, provided the alternative final cover system is designed and constructed to meet the criteria in paragraphs (f)(3)(ii)(A) through (D) of this section. The design of the final cover system must be included in the written closure plan required by paragraph (b) of this section.

(A) The design of the final cover system must include an infiltration layer that achieves an equivalent reduction in infiltration as the infiltration layer specified in paragraphs (d)(3)(i)(A) and (B) of this section.

(B) The design of the final cover system must include an erosion layer that provides equivalent protection from wind or water erosion as the erosion layer specified in paragraph (d)(3)(i)(C) of this section.

(C) The disruption of the integrity of the final cover system must be minimized through a design that accommodates settling and subsidence.

(iii) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer that the design of the final cover system meets the requirements of this section.

(e) *Initiation of closure activities.* Except as provided for in paragraph (e)(4) of this section and § 257.103, the owner or operator of a CCR unit must commence closure of the CCR unit no later than the applicable timeframes specified in either paragraph (e)(1) or (2) of this section.

(1) The owner or operator must commence closure of the CCR unit no later than 30 days after the date on which the CCR unit either:

(i) Receives the known final receipt of waste, either CCR or any non-CCR waste stream; or

(ii) Removes the known final volume of CCR from the CCR unit for the purpose of beneficial use of CCR.

(2)(i) Except as provided by paragraph (e)(2)(ii) of this section, the owner or operator must commence closure of a CCR unit that has not received CCR or any non-CCR waste stream or is no longer removing CCR for the purpose of beneficial use within two years of the last receipt of waste or within two years of the last removal of CCR material for the purpose of beneficial use.

(ii) Notwithstanding paragraph (e)(2)(i) of this section, the owner or operator of the CCR unit may secure an additional two years to initiate closure of the idle unit provided the owner or operator provides written documentation that the CCR unit will continue to accept wastes or will start removing CCR for the purpose of beneficial use. The documentation must be supported by, at a minimum, the information specified in paragraphs (e)(2)(ii)(A) and (B) of this section. The owner or operator may obtain two-year extensions provided the owner or operator continues to be able to demonstrate that there is reasonable likelihood that the CCR unit will accept wastes in the foreseeable future or will remove CCR from the unit for the purpose of beneficial use. The owner or operator must place each completed demonstration, if more than one time extension is sought, in the facility's operating record as required by § 257.105(i)(5) prior to the end of any two-year period.

(A) Information documenting that the CCR unit has remaining storage or disposal capacity or that the CCR unit can have CCR removed for the purpose of beneficial use; and

(B) Information demonstrating that that there is a reasonable likelihood that the CCR unit will resume receiving CCR or non-CCR waste streams in the foreseeable future or that CCR can be removed for the purpose of beneficial use. The narrative must include a best estimate as to when the CCR unit will resume receiving CCR or non-CCR waste streams. The situations listed in paragraphs (e)(2)(ii)(B)(*1*) through (*4*) of this section are examples of situations that would support a determination that the CCR unit will resume receiving CCR or non-CCR waste streams in the foreseeable future.

(*1*) Normal plant operations include periods during which the CCR unit does not receive CCR or non-CCR waste

streams, such as the alternating use of two or more CCR units whereby at any point in time one CCR unit is receiving CCR while CCR is being removed from a second CCR unit after its dewatering.

(*2*) The CCR unit is dedicated to a coal-fired boiler unit that is temporarily idled (*e.g.,* CCR is not being generated) and there is a reasonable likelihood that the coal-fired boiler will resume operations in the future.

(*3*) The CCR unit is dedicated to an operating coal-fired boiler (*i.e.,* CCR is being generated); however, no CCR are being placed in the CCR unit because the CCR are being entirely diverted to beneficial uses, but there is a reasonable likelihood that the CCR unit will again be used in the foreseeable future.

(*4*) The CCR unit currently receives only non-CCR waste streams and those non-CCR waste streams are not generated for an extended period of time, but there is a reasonable likelihood that the CCR unit will again receive non-CCR waste streams in the future.

(iii) In order to obtain additional time extension(s) to initiate closure of a CCR unit beyond the two years provided by paragraph (e)(2)(i) of this section, the owner or operator of the CCR unit must include with the demonstration required by paragraph (e)(2)(ii) of this section the following statement signed by the owner or operator or an authorized representative:

> I certify under penalty of law that I have personally examined and am familiar with the information submitted in this demonstration and all attached documents, and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the submitted information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

(3) For purposes of this subpart, closure of the CCR unit has commenced if the owner or operator has ceased placing waste and completes any of the following actions or activities:

(i) Taken any steps necessary to implement the written closure plan required by paragraph (b) of this section;

(ii) Submitted a completed application for any required state or agency permit or permit modification; or

(iii) Taken any steps necessary to comply with any state or other agency standards that are a prerequisite, or are otherwise applicable, to initiating or completing the closure of a CCR unit.

(4) The timeframes specified in paragraphs (e)(1) and (2) of this section do not apply to any of the following owners or operators:

(i) An owner or operator of an inactive CCR surface impoundment closing the CCR unit as required by § 257.100(b);

(ii) An owner or operator of an existing unlined CCR surface impoundment closing the CCR unit as required by § 257.101(a);

(iii) An owner or operator of an existing CCR surface impoundment closing the CCR unit as required by § 257.101(b);

(iv) An owner or operator of a new CCR surface impoundment closing the CCR unit as required by § 257.101(c); or

(v) An owner or operator of an existing CCR landfill closing the CCR unit as required by § 257.101(d).

(f) *Completion of closure activities.* (1) Except as provided for in paragraph (f)(2) of this section, the owner or operator must complete closure of the CCR unit:

(i) For existing and new CCR landfills and any lateral expansion of a CCR landfill, within six months of commencing closure activities.

(ii) For existing and new CCR surface impoundments and any lateral expansion of a CCR surface impoundment, within five years of commencing closure activities.

(2)(i) *Extensions of closure timeframes.* The timeframes for completing closure of a CCR unit specified under paragraphs (f)(1) of this section may be extended if the owner or operator can demonstrate that it was not feasible to complete closure of the CCR unit within the required timeframes due to factors beyond the facility's control. If the owner or operator is seeking a time extension beyond the time specified in the written closure plan as required by paragraph (b)(1) of this section, the demonstration must include a narrative discussion providing the basis for additional time beyond that specified in the closure plan. The owner or operator must place each completed demonstration, if more than one time extension is sought, in the facility's operating record as required by § 257.105(i)(6) prior to the end of any two-year period. Factors that may support such a demonstration include:

(A) Complications stemming from the climate and weather, such as unusual amounts of precipitation or a significantly shortened construction season;

(B) Time required to dewater a surface impoundment due to the volume of CCR contained in the CCR unit or the characteristics of the CCR in the unit;

(C) The geology and terrain surrounding the CCR unit will affect the amount of material needed to close the CCR unit; or

(D) Time required or delays caused by the need to coordinate with and obtain necessary approvals and permits from a state or other agency.

(ii) *Maximum time extensions.* (A) CCR surface impoundments of 40 acres or smaller may extend the time to complete closure by no longer than two years.

(B) CCR surface impoundments larger than 40 acres may extend the timeframe to complete closure of the CCR unit multiple times, in two-year increments. For each two-year extension sought, the owner or operator must substantiate the factual circumstances demonstrating the need for the extension. No more than a total of five two-year extensions may be obtained for any CCR surface impoundment.

(C) CCR landfills may extend the timeframe to complete closure of the CCR unit multiple times, in one-year increments. For each one-year extension sought, the owner or operator must substantiate the factual circumstances demonstrating the need for the extension. No more than a total of two one-year extensions may be obtained for any CCR landfill.

(iii) In order to obtain additional time extension(s) to complete closure of a CCR unit beyond the times provided by paragraph (f)(1) of this section, the owner or operator of the CCR unit must include with the demonstration required by paragraph (f)(2)(i) of this section the following statement signed by the owner or operator or an authorized representative:

> I certify under penalty of law that I have personally examined and am familiar with the information submitted in this demonstration and all attached documents, and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the submitted information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

(3) Upon completion, the owner or operator of the CCR unit must obtain a certification from a qualified professional engineer verifying that closure has been completed in accordance with the closure plan specified in paragraph (b) of this section and the requirements of this section.

(g) No later than the date the owner or operator initiates closure of a CCR unit, the owner or operator must prepare a notification of intent to close a CCR unit. The notification must include the certification by a qualified professional engineer for the design of the final cover system as required by § 257.102(d)(3)(iii), if applicable. The

owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(7).

(h) Within 30 days of completion of closure of the CCR unit, the owner or operator must prepare a notification of closure of a CCR unit. The notification must include the certification by a qualified professional engineer as required by § 257.102(f)(3). The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(8).

(i) *Deed notations.* (1) Except as provided by paragraph (i)(4) of this section, following closure of a CCR unit, the owner or operator must record a notation on the deed to the property, or some other instrument that is normally examined during title search.

(2) The notation on the deed must in perpetuity notify any potential purchaser of the property that:

(i) The land has been used as a CCR unit; and

(ii) Its use is restricted under the post-closure care requirements as provided by § 257.104(d)(1)(iii).

(3) Within 30 days of recording a notation on the deed to the property, the owner or operator must prepare a notification stating that the notation has been recorded. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(9).

(4) An owner or operator that closes a CCR unit in accordance with paragraph (c) of this section is not subject to the requirements of paragraphs (i)(1) through (3) of this section.

(j) The owner or operator of the CCR unit must comply with the closure recordkeeping requirements specified in § 257.105(i), the closure notification requirements specified in § 257.106(i), and the closure Internet requirements specified in § 257.107(i).

(k) *Criteria to retrofit an existing CCR surface impoundment.* (1) To retrofit an existing CCR surface impoundment, the owner or operator must:

(i) First remove all CCR, including any contaminated soils and sediments from the CCR unit; and

(ii) Comply with the requirements in § 257.72.

(iii) A CCR surface impoundment undergoing a retrofit remains subject to all other requirements of this subpart, including the requirement to conduct any necessary corrective action.

(2) *Written retrofit plan*—(i) *Content of the plan.* The owner or operator must prepare a written retrofit plan that describes the steps necessary to retrofit the CCR unit consistent with recognized and generally accepted good engineering practices. The written retrofit plan must include, at a minimum, all of the following information:

(A) A narrative description of the specific measures that will be taken to retrofit the CCR unit in accordance with this section.

(B) A description of the procedures to remove all CCR and contaminated soils and sediments from the CCR unit.

(C) An estimate of the maximum amount of CCR that will be removed as part of the retrofit operation.

(D) An estimate of the largest area of the CCR unit that will be affected by the retrofit operation.

(E) A schedule for completing all activities necessary to satisfy the retrofit criteria in this section, including an estimate of the year in which retrofit activities of the CCR unit will be completed.

(ii) *Timeframes for preparing the initial written retrofit plan.* (A) No later than 60 days prior to date of initiating retrofit activities, the owner or operator must prepare an initial written retrofit plan consistent with the requirements specified in paragraph (k)(2) of this section. For purposes of this subpart, initiation of retrofit activities has commenced if the owner or operator has ceased placing waste in the unit and completes any of the following actions or activities:

(*1*) Taken any steps necessary to implement the written retrofit plan;

(*2*) Submitted a completed application for any required state or agency permit or permit modification; or

(*3*) Taken any steps necessary to comply with any state or other agency standards that are a prerequisite, or are otherwise applicable, to initiating or completing the retrofit of a CCR unit.

(B) The owner or operator has completed the written retrofit plan when the plan, including the certification required by paragraph (k)(2)(iv) of this section, has been placed in the facility's operating record as required by § 257.105(j)(1).

(iii) *Amendment of a written retrofit plan.* (A) The owner or operator may amend the initial or any subsequent written retrofit plan at any time.

(B) The owner or operator must amend the written retrofit plan whenever:

(*1*) There is a change in the operation of the CCR unit that would substantially affect the written retrofit plan in effect; or

(*2*) Before or after retrofit activities have commenced, unanticipated events necessitate a revision of the written retrofit plan.

(C) The owner or operator must amend the retrofit plan at least 60 days prior to a planned change in the operation of the facility or CCR unit, or no later than 60 days after an unanticipated event requires the revision of an existing written retrofit plan. If a written retrofit plan is revised after retrofit activities have commenced for a CCR unit, the owner or operator must amend the current retrofit plan no later than 30 days following the triggering event.

(iv) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer that the activities outlined in the written retrofit plan, including any amendment of the plan, meet the requirements of this section.

(3) *Deadline for completion of activities related to the retrofit of a CCR unit.* Any CCR surface impoundment that is being retrofitted must complete all retrofit activities within the same time frames and procedures specified for the closure of a CCR surface impoundment in § 257.102(f) or, where applicable, § 257.103.

(4) Upon completion, the owner or operator must obtain a certification from a qualified professional engineer verifying that the retrofit activities have been completed in accordance with the retrofit plan specified in paragraph (k)(2) of this section and the requirements of this section.

(5) No later than the date the owner or operator initiates the retrofit of a CCR unit, the owner or operator must prepare a notification of intent to retrofit a CCR unit. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(j)(5).

(6) Within 30 days of completing the retrofit activities specified in paragraph (k)(1) of this section, the owner or operator must prepare a notification of completion of retrofit activities. The notification must include the certification by a qualified professional engineer as required by paragraph (k)(4) of this section. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(j)(6).

(7) At any time after the initiation of a CCR unit retrofit, the owner or operator may cease the retrofit and initiate closure of the CCR unit in accordance with the requirements of § 257.102.

(8) The owner or operator of the CCR unit must comply with the retrofit recordkeeping requirements specified in

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§ 257.105(j), the retrofit notification requirements specified in § 257.106(j), and the retrofit Internet requirements specified in § 257.107(j).

**§ 257.103 Alternative closure requirements.**

The owner or operator of a CCR landfill, CCR surface impoundment, or any lateral expansion of a CCR unit that is subject to closure pursuant to § 257.101(a), (b)(1), or (d) may continue to receive CCR in the unit provided the owner or operator meets the requirements of either paragraph (a) or (b) of this section.

(a)(1) *No alternative CCR disposal capacity.* Notwithstanding the provisions of § 257.101(a), (b)(1), or (d), a CCR unit may continue to receive CCR if the owner or operator of the CCR unit certifies that the CCR must continue to be managed in that CCR unit due to the absence of alternative disposal capacity both on-site and off-site of the facility. To qualify under this paragraph (a)(1), the owner or operator of the CCR unit must document that all of the following conditions have been met:

(i) No alternative disposal capacity is available on-site or off-site. An increase in costs or the inconvenience of existing capacity is not sufficient to support qualification under this section;

(ii) The owner or operator has made, and continues to make, efforts to obtain additional capacity. Qualification under this subsection lasts only as long as no alternative capacity is available. Once alternative capacity is identified, the owner or operator must arrange to use such capacity as soon as feasible;

(iii) The owner or operator must remain in compliance with all other requirements of this subpart, including the requirement to conduct any necessary corrective action; and

(iv) The owner or operator must prepare an annual progress report documenting the continued lack of alternative capacity and the progress towards the development of alternative CCR disposal capacity.

(2) Once alternative capacity is available, the CCR unit must cease receiving CCR and initiate closure following the timeframes in § 257.102(e) and (f).

(3) If no alternative capacity is identified within five years after the initial certification, the CCR unit must cease receiving CCR and close in accordance with the timeframes in § 257.102(e) and (f).

(b)(1) *Permanent cessation of a coal-fired boiler(s) by a date certain.* Notwithstanding the provisions of § 257.101(a), (b)(1), and (d), a CCR unit may continue to receive CCR if the owner or operator certifies that the facility will cease operation of the coal-fired boilers within the timeframes specified in paragraphs (b)(2) through (4) of this section, but in the interim period (prior to closure of the coal-fired boiler), the facility must continue to use the CCR unit due to the absence of alternative disposal capacity both on-site and off-site of the facility. To qualify under this paragraph (b)(1), the owner or operator of the CCR unit must document that all of the following conditions have been met:

(i) No alternative disposal capacity is available on-site or off-site. An increase in costs or the inconvenience of existing capacity is not sufficient to support qualification under this section.

(ii) The owner or operator must remain in compliance with all other requirements of this subpart, including the requirement to conduct any necessary corrective action; and

(iii) The owner or operator must prepare an annual progress report documenting the continued lack of alternative capacity and the progress towards the closure of the coal-fired boiler.

(2) For a CCR surface impoundment that is 40 acres or smaller, the coal-fired boiler must cease operation and the CCR surface impoundment must have completed closure no later than October 17, 2023.

(3) For a CCR surface impoundment that is larger than 40 acres, the coal-fired boiler must cease operation, and the CCR surface impoundment must complete closure no later than October 17, 2028.

(4) For a CCR landfill, the coal-fired boiler must cease operation, and the CCR landfill must complete closure no later than April 19, 2021.

(c) Required notices and progress reports. An owner or operator of a CCR unit that closes in accordance with paragraphs (a) or (b) of this section must complete the notices and progress reports specified in paragraphs (c)(1) through (3) of this section.

(1) Within six months of becoming subject to closure pursuant to § 257.101(a), (b)(1), or (d), the owner or operator must prepare and place in the facility's operating record a notification of intent to comply with the alternative closure requirements of this section. The notification must describe why the CCR unit qualifies for the alternative closure provisions under either paragraph (a) or (b) of this section, in addition to providing the documentation and certifications required by paragraph (a) or (b) of this section.

(2) The owner or operator must prepare the periodic progress reports required by paragraphs (a)(1)(iv) or (b)(1)(iii), in addition to describing any problems encountered and a description of the actions taken to resolve the problems. The annual progress reports must be completed according to the following schedule:

(i) The first annual progress report must be prepared no later than 13 months after completing the notification of intent to comply with the alternative closure requirements required by paragraph (c)(1) of this section.

(ii) The second annual progress report must be prepared no later than 12 months after completing the first annual progress report. Additional annual progress reports must be prepared within 12 months of completing the previous annual progress report.

(iii) The owner or operator has completed the progress reports specified in paragraph (c)(2) of this section when the reports are placed in the facility's operating record as required by § 257.105(i)(10).

(3) An owner or operator of a CCR unit must also prepare the notification of intent to close a CCR unit as required by § 257.102(g).

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(i), the notification requirements specified in § 257.106(i), and the Internet requirements specified in § 257.107(i).

**§ 257.104 Post-closure care requirements.**

(a) *Applicability.* (1) Except as provided by either paragraph (a)(2) or (3) of this section, § 257.104 applies to the owners or operators of CCR landfills, CCR surface impoundments, and all lateral expansions of CCR units that are subject to the closure criteria under § 257.102.

(2) An owner or operator of a CCR unit that elects to close a CCR unit by removing CCR as provided by § 257.102(c) is not subject to the post-closure care criteria under this section.

(3) An owner or operator of an inactive CCR surface impoundment that elects to close a CCR unit pursuant to the requirements under § 257.100(b) is not subject to the post-closure care criteria under this section.

(b) *Post-closure care maintenance requirements.* Following closure of the CCR unit, the owner or operator must conduct post-closure care for the CCR unit, which must consist of at least the following:

(1) Maintaining the integrity and effectiveness of the final cover system, including making repairs to the final

cover as necessary to correct the effects of settlement, subsidence, erosion, or other events, and preventing run-on and run-off from eroding or otherwise damaging the final cover;

(2) If the CCR unit is subject to the design criteria under § 257.70, maintaining the integrity and effectiveness of the leachate collection and removal system and operating the leachate collection and removal system in accordance with the requirements of § 257.70; and

(3) Maintaining the groundwater monitoring system and monitoring the groundwater in accordance with the requirements of §§ 257.90 through 257.98.

(c) *Post-closure care period.* (1) Except as provided by paragraph (c)(2) of this section, the owner or operator of the CCR unit must conduct post-closure care for 30 years.

(2) If at the end of the post-closure care period the owner or operator of the CCR unit is operating under assessment monitoring in accordance with § 257.95, the owner or operator must continue to conduct post-closure care until the owner or operator returns to detection monitoring in accordance with § 257.95.

(d) *Written post-closure plan*—(1) *Content of the plan.* The owner or operator of a CCR unit must prepare a written post-closure plan that includes, at a minimum, the information specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) A description of the monitoring and maintenance activities required in paragraph (b) of this section for the CCR unit, and the frequency at which these activities will be performed;

(ii) The name, address, telephone number, and email address of the person or office to contact about the facility during the post-closure care period; and

(iii) A description of the planned uses of the property during the post-closure period. Post-closure use of the property shall not disturb the integrity of the final cover, liner(s), or any other component of the containment system, or the function of the monitoring systems unless necessary to comply with the requirements in this subpart. Any other disturbance is allowed if the owner or operator of the CCR unit demonstrates that disturbance of the final cover, liner, or other component of the containment system, including any removal of CCR, will not increase the potential threat to human health or the environment. The demonstration must be certified by a qualified professional engineer, and notification shall be provided to the State Director that the demonstration has been placed in the operating record and on the owners or operator's publicly accessible Internet site.

(2) *Deadline to prepare the initial written post-closure plan*—(i) *Existing CCR landfills and existing CCR surface impoundments.* No later than October 17, 2016, the owner or operator of the CCR unit must prepare an initial written post-closure plan consistent with the requirements specified in paragraph (d)(1) of this section.

(ii) *New CCR landfills, new CCR surface impoundments, and any lateral expansion of a CCR unit.* No later than the date of the initial receipt of CCR in the CCR unit, the owner or operator must prepare an initial written post-closure plan consistent with the requirements specified in paragraph (d)(1) of this section.

(iii) The owner or operator has completed the written post-closure plan when the plan, including the certification required by paragraph (d)(4) of this section, has been placed in the facility's operating record as required by § 257.105(i)(4).

(3) *Amendment of a written post-closure plan.* (i) The owner or operator may amend the initial or any subsequent written post-closure plan developed pursuant to paragraph (d)(1) of this section at any time.

(ii) The owner or operator must amend the written closure plan whenever:

(A) There is a change in the operation of the CCR unit that would substantially affect the written post-closure plan in effect; or

(B) After post-closure activities have commenced, unanticipated events necessitate a revision of the written post-closure plan.

(iii) The owner or operator must amend the written post-closure plan at least 60 days prior to a planned change in the operation of the facility or CCR unit, or no later than 60 days after an unanticipated event requires the need to revise an existing written post-closure plan. If a written post-closure plan is revised after post-closure activities have commenced for a CCR unit, the owner or operator must amend the written post-closure plan no later than 30 days following the triggering event.

(4) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer that the initial and any amendment of the written post-closure plan meets the requirements of this section.

(e) *Notification of completion of post-closure care period.* No later than 60 days following the completion of the post-closure care period, the owner or operator of the CCR unit must prepare a notification verifying that post-closure care has been completed. The notification must include the certification by a qualified professional engineer verifying that post-closure care has been completed in accordance with the closure plan specified in paragraph (d) of this section and the requirements of this section. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(13).

(f) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(i), the notification requirements specified in § 257.106(i), and the Internet requirements specified in § 257.107(i).

## Recordkeeping, Notification, and Posting of Information to the Internet

### § 257.105 Recordkeeping requirements.

(a) Each owner or operator of a CCR unit subject to the requirements of this subpart must maintain files of all information required by this section in a written operating record at their facility.

(b) Unless specified otherwise, each file must be retained for at least five years following the date of each occurrence, measurement, maintenance, corrective action, report, record, or study.

(c) An owner or operator of more than one CCR unit subject to the provisions of this subpart may comply with the requirements of this section in one recordkeeping system provided the system identifies each file by the name of each CCR unit. The files may be maintained on microfilm, on a computer, on computer disks, on a storage system accessible by a computer, on magnetic tape disks, or on microfiche.

(d) The owner or operator of a CCR unit must submit to the State Director and/or appropriate Tribal authority any demonstration or documentation required by this subpart, if requested, when such information is not otherwise available on the owner or operator's publicly accessible Internet site.

(e) *Location restrictions.* The owner or operator of a CCR unit subject to this subpart must place the demonstrations documenting whether or not the CCR unit is in compliance with the requirements under §§ 257.60(a), 257.61(a), 257.62(a), 257.63(a), and 257.64(a), as it becomes available, in the facility's operating record.

(f) *Design criteria.* The owner or operator of a CCR unit subject to this subpart must place the following

information, as it becomes available, in the facility's operating record:

(1) The design and construction certifications as required by § 257.70(e) and (f).

(2) The documentation of liner type as required by § 257.71(a).

(3) The design and construction certifications as required by § 257.72(c) and (d).

(4) Documentation prepared by the owner or operator stating that the permanent identification marker was installed as required by §§ 257.73(a)(1) and 257.74(a)(1).

(5) The initial and periodic hazard potential classification assessments as required by §§ 257.73(a)(2) and 257.74(a)(2).

(6) The emergency action plan (EAP), and any amendment of the EAP, as required by §§ 257.73(a)(3) and 257.74(a)(3), except that only the most recent EAP must be maintained in the facility's operating record irrespective of the time requirement specified in paragraph (b) of this section.

(7) Documentation prepared by the owner or operator recording the annual face-to-face meeting or exercise between representatives of the owner or operator of the CCR unit and the local emergency responders as required by §§ 257.73(a)(3)(i)(E) and 257.74(a)(3)(i)(E).

(8) Documentation prepared by the owner or operator recording all activations of the emergency action plan as required by §§ 257.73(a)(3)(v) and 257.74(a)(3)(v).

(9) The history of construction, and any revisions of it, as required by § 257.73(c), except that these files must be maintained until the CCR unit completes closure of the unit in accordance with § 257.102.

(10) The initial and periodic structural stability assessments as required by §§ 257.73(d) and 257.74(d).

(11) Documentation detailing the corrective measures taken to remedy the deficiency or release as required by §§ 257.73(d)(2) and 257.74(d)(2).

(12) The initial and periodic safety factor assessments as required by §§ 257.73(e) and 257.74(e).

(13) The design and construction plans, and any revisions of it, as required by § 257.74(c), except that these files must be maintained until the CCR unit completes closure of the unit in accordance with § 257.102.

(g) *Operating criteria.* The owner or operator of a CCR unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

(1) The CCR fugitive dust control plan, and any subsequent amendment of the plan, required by § 257.80(b), except that only the most recent control plan must be maintained in the facility's operating record irrespective of the time requirement specified in paragraph (b) of this section.

(2) The annual CCR fugitive dust control report required by § 257.80(c).

(3) The initial and periodic run-on and run-off control system plans as required by § 257.81(c).

(4) The initial and periodic inflow design flood control system plan as required by § 257.82(c).

(5) Documentation recording the results of each inspection and instrumentation monitoring by a qualified person as required by § 257.83(a).

(6) The periodic inspection report as required by § 257.83(b)(2).

(7) Documentation detailing the corrective measures taken to remedy the deficiency or release as required by §§ 257.83(b)(5) and 257.84(b)(5).

(8) Documentation recording the results of the weekly inspection by a qualified person as required by § 257.84(a).

(9) The periodic inspection report as required by § 257.84(b)(2).

(h) *Groundwater monitoring and corrective action.* The owner or operator of a CCR unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

(1) The annual groundwater monitoring and corrective action report as required by § 257.90(e).

(2) Documentation of the design, installation, development, and decommissioning of any monitoring wells, piezometers and other measurement, sampling, and analytical devices as required by § 257.91(e)(1).

(3) The groundwater monitoring system certification as required by § 257.91(f).

(4) The selection of a statistical method certification as required by § 257.93(f)(6).

(5) Within 30 days of establishing an assessment monitoring program, the notification as required by § 257.94(e)(3).

(6) The results of appendices III and IV to this part constituent concentrations as required by § 257.95(d)(1).

(7) Within 30 days of returning to a detection monitoring program, the notification as required by § 257.95(e).

(8) Within 30 days of detecting one or more constituents in appendix IV to this part at statistically significant levels above the groundwater protection standard, the notifications as required by § 257.95(g).

(9) Within 30 days of initiating the assessment of corrective measures requirements, the notification as required by § 257.95(g)(5).

(10) The completed assessment of corrective measures as required by § 257.96(d).

(11) Documentation prepared by the owner or operator recording the public meeting for the corrective measures assessment as required by § 257.96(e).

(12) The semiannual report describing the progress in selecting and designing the remedy and the selection of remedy report as required by § 257.97(a), except that the selection of remedy report must be maintained until the remedy has been completed.

(13) Within 30 days of completing the remedy, the notification as required by § 257.98(e).

(i) *Closure and post-closure care.* The owner or operator of a CCR unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

(1) The notification of intent to initiate closure of the CCR unit as required by § 257.100(c)(1).

(2) The annual progress reports of closure implementation as required by § 257.100(c)(2)(i) and (ii).

(3) The notification of closure completion as required by § 257.100(c)(3).

(4) The written closure plan, and any amendment of the plan, as required by § 257.102(b), except that only the most recent closure plan must be maintained in the facility's operating record irrespective of the time requirement specified in paragraph (b) of this section.

(5) The written demonstration(s), including the certification required by § 257.102(e)(2)(iii), for a time extension for initiating closure as required by § 257.102(e)(2)(ii).

(6) The written demonstration(s), including the certification required by § 257.102(f)(2)(iii), for a time extension for completing closure as required by § 257.102(f)(2)(i).

(7) The notification of intent to close a CCR unit as required by § 257.102(g).

(8) The notification of completion of closure of a CCR unit as required by § 257.102(h).

(9) The notification recording a notation on the deed as required by § 257.102(i).

(10) The notification of intent to comply with the alternative closure requirements as required by § 257.103(c)(1).

(11) The annual progress reports under the alternative closure requirements as required by § 257.103(c)(2).

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(12) The written post-closure plan, and any amendment of the plan, as required by § 257.104(d), except that only the most recent closure plan must be maintained in the facility's operating record irrespective of the time requirement specified in paragraph (b) of this section.

(13) The notification of completion of post-closure care period as required by § 257.104(e).

(j) *Retrofit criteria.* The owner or operator of a CCR unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

(1) The written retrofit plan, and any amendment of the plan, as required by § 257.102(k)(2), except that only the most recent retrofit plan must be maintained in the facility's operating record irrespective of the time requirement specified in paragraph (b) of this section.

(2) The notification of intent that the retrofit activities will proceed in accordance with the alternative procedures in § 257.103.

(3) The annual progress reports required under the alternative requirements as required by § 257.103.

(4) The written demonstration(s), including the certification in § 257.102(f)(2)(iii), for a time extension for completing retrofit activities as required by § 257.102(k)(3).

(5) The notification of intent to initiate retrofit of a CCR unit as required by § 257.102(k)(5).

(6) The notification of completion of retrofit activities as required by § 257.102(k)(6).

**§ 257.106 Notification requirements.**

(a) The notifications required under paragraphs (e) through (i) of this section must be sent to the relevant State Director and/or appropriate Tribal authority before the close of business on the day the notification is required to be completed. For purposes of this section, *before the close of business* means the notification must be postmarked or sent by electronic mail (email). If a notification deadline falls on a weekend or federal holiday, the notification deadline is automatically extended to the next business day.

(b) If any CCR unit is located in its entirety within Indian Country, the notifications of this section must be sent to the appropriate Tribal authority. If any CCR unit is located in part within Indian Country, the notifications of this section must be sent both to the appropriate State Director and Tribal authority.

(c) Notifications may be combined as long as the deadline requirement for each notification is met.

(d) Unless otherwise required in this section, the notifications specified in this section must be sent to the State Director and/or appropriate Tribal authority within 30 days of placing in the operating record the information required by § 257.105.

(e) *Location restrictions.* The owner or operator of a CCR unit subject to the requirements of this subpart must notify the State Director and/or appropriate Tribal authority that each demonstration specified under § 257.105(e) has been placed in the operating record and on the owner or operator's publicly accessible internet site.

(f) *Design criteria.* The owner or operator of a CCR unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible internet site. The owner or operator must:

(1) Within 60 days of commencing construction of a new CCR unit, provide notification of the availability of the design certification specified under § 257.105(f)(1) or (3). If the owner or operator of the CCR unit elects to install an alternative composite liner, the owner or operator must also submit to the State Director and/or appropriate Tribal authority a copy of the alternative composite liner design.

(2) No later than the date of initial receipt of CCR by a new CCR unit, provide notification of the availability of the construction certification specified under § 257.105(f)(1) or (3).

(3) Provide notification of the availability of the documentation of liner type specified under § 257.105(f)(2).

(4) Provide notification of the availability of the initial and periodic hazard potential classification assessments specified under § 257.105(f)(5).

(5) Provide notification of the availability of emergency action plan (EAP), and any revisions of the EAP, specified under § 257.105(f)(6).

(6) Provide notification of the availability of documentation prepared by the owner or operator recording the annual face-to-face meeting or exercise between representatives of the owner or operator of the CCR unit and the local emergency responders specified under § 257.105(f)(7).

(7) Provide notification of documentation prepared by the owner or operator recording all activations of the emergency action plan specified under § 257.105(f)(8).

(8) Provide notification of the availability of the history of construction, and any revision of it, specified under § 257.105(f)(9).

(9) Provide notification of the availability of the initial and periodic structural stability assessments specified under § 257.105(f)(10).

(10) Provide notification of the availability of the documentation detailing the corrective measures taken to remedy the deficiency or release specified under § 257.105(f)(11).

(11) Provide notification of the availability of the initial and periodic safety factor assessments specified under § 257.105(f)(12).

(12) Provide notification of the availability of the design and construction plans, and any revision of them, specified under § 257.105(f)(13).

(g) *Operating criteria.* The owner or operator of a CCR unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible internet site. The owner or operator must:

(1) Provide notification of the availability of the CCR fugitive dust control plan, or any subsequent amendment of the plan, specified under § 257.105(g)(1).

(2) Provide notification of the availability of the annual CCR fugitive dust control report specified under § 257.105(g)(2).

(3) Provide notification of the availability of the initial and periodic run-on and run-off control system plans specified under § 257.105(g)(3).

(4) Provide notification of the availability of the initial and periodic inflow design flood control system plans specified under § 257.105(g)(4).

(5) Provide notification of the availability of the periodic inspection reports specified under § 257.105(g)(6).

(6) Provide notification of the availability of the documentation detailing the corrective measures taken to remedy the deficiency or release specified under § 257.105(g)(7).

(7) Provide notification of the availability of the periodic inspection reports specified under § 257.105(g)(9).

(h) *Groundwater monitoring and corrective action.* The owner or operator of a CCR unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible internet site. The owner or operator must:

(1) Provide notification of the availability of the annual groundwater

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monitoring and corrective action report specified under § 257.105(h)(1).

(2) Provide notification of the availability of the groundwater monitoring system certification specified under § 257.105(h)(3).

(3) Provide notification of the availability of the selection of a statistical method certification specified under § 257.105(h)(4).

(4) Provide notification that an assessment monitoring programs has been established specified under § 257.105(h)(5).

(5) Provide notification that the CCR unit is returning to a detection monitoring program specified under § 257.105(h)(7).

(6) Provide notification that one or more constituents in appendix IV to this part have been detected at statistically significant levels above the groundwater protection standard and the notifications to land owners specified under § 257.105(h)(8).

(7) Provide notification that an assessment of corrective measures has been initiated specified under § 257.105(h)(9).

(8) Provide notification of the availability of assessment of corrective measures specified under § 257.105(h)(10).

(9) Provide notification of the availability of the semiannual report describing the progress in selecting and designing the remedy and the selection of remedy report specified under § 257.105(h)(12).

(10) Provide notification of the completion of the remedy specified under § 257.105(h)(13).

(i) *Closure and post-closure care.* The owner or operator of a CCR unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible Internet site. The owner or operator must:

(1) Provide notification of the intent to initiate closure of the CCR unit specified under § 257.105(i)(1).

(2) Provide notification of the availability of the annual progress reports of closure implementation specified under § 257.105(i)(2).

(3) Provide notification of closure completion specified under § 257.105(i)(3).

(4) Provide notification of the availability of the written closure plan, and any amendment of the plan, specified under § 257.105(i)(4).

(5) Provide notification of the availability of the demonstration(s) for a time extension for initiating closure specified under § 257.105(i)(5).

(6) Provide notification of the availability of the demonstration(s) for a time extension for completing closure specified under § 257.105(i)(6).

(7) Provide notification of intent to close a CCR unit specified under § 257.105(i)(7).

(8) Provide notification of completion of closure of a CCR unit specified under § 257.105(i)(8).

(9) Provide notification of the deed notation as required by § 257.105(i)(9).

(10) Provide notification of intent to comply with the alternative closure requirements specified under § 257.105(i)(10).

(11) The annual progress reports under the alternative closure requirements as required by § 257.105(i)(11).

(12) Provide notification of the availability of the written post-closure plan, and any amendment of the plan, specified under § 257.105(i)(12).

(13) Provide notification of completion of post-closure care specified under § 257.105(i)(13).

(j) *Retrofit criteria.* The owner or operator of a CCR unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible Internet site. The owner or operator must:

(1) Provide notification of the availability of the written retrofit plan, and any amendment of the plan, specified under § 257.105(j)(1).

(2) Provide notification of intent to comply with the alternative retrofit requirements specified under § 257.105(j)(2).

(3) The annual progress reports under the alternative retrofit requirements as required by § 257.105(j)(3).

(4) Provide notification of the availability of the demonstration(s) for a time extension for completing retrofit activities specified under § 257.105(j)(4).

(5) Provide notification of intent to initiate retrofit of a CCR unit specified under § 257.105(j)(5).

(6) Provide notification of completion of retrofit activities specified under § 257.105(j)(6).

**§ 257.107 Publicly accessible Internet site requirements.**

(a) Each owner or operator of a CCR unit subject to the requirements of this subpart must maintain a publicly accessible Internet site (CCR Web site) containing the information specified in this section. The owner or operator's Web site must be titled "CCR Rule Compliance Data and Information."

(b) An owner or operator of more than one CCR unit subject to the provisions of this subpart may comply with the requirements of this section by using the same Internet site for multiple CCR units provided the CCR Web site clearly delineates information by the name or identification number of each unit.

(c) Unless otherwise required in this section, the information required to be posted to the CCR Web site must be made available to the public for at least five years following the date on which the information was first posted to the CCR Web site.

(d) Unless otherwise required in this section, the information must be posted to the CCR Web site within 30 days of placing the pertinent information required by § 257.105 in the operating record.

(e) *Location restrictions.* The owner or operator of a CCR unit subject to this subpart must place each demonstration specified under § 257.105(e) on the owner or operator's CCR Web site.

(f) *Design criteria.* The owner or operator of a CCR unit subject to this subpart must place the following information on the owner or operator's CCR Web site:

(1) Within 60 days of commencing construction of a new unit, the design certification specified under § 257.105(f)(1) or (3).

(2) No later than the date of initial receipt of CCR by a new CCR unit, the construction certification specified under § 257.105(f)(1) or (3).

(3) The documentation of liner type specified under § 257.105(f)(2).

(4) The initial and periodic hazard potential classification assessments specified under § 257.105(f)(5).

(5) The emergency action plan (EAP) specified under § 257.105(f)(6), except that only the most recent EAP must be maintained on the CCR Web site irrespective of the time requirement specified in paragraph (c) of this section.

(6) Documentation prepared by the owner or operator recording the annual face-to-face meeting or exercise between representatives of the owner or operator of the CCR unit and the local emergency responders specified under § 257.105(f)(7).

(7) Documentation prepared by the owner or operator recording any activation of the emergency action plan specified under § 257.105(f)(8).

(8) The history of construction, and any revisions of it, specified under § 257.105(f)(9).

(9) The initial and periodic structural stability assessments specified under § 257.105(f)(10).

(10) The documentation detailing the corrective measures taken to remedy the

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deficiency or release specified under § 257.105(f)(11).

(11) The initial and periodic safety factor assessments specified under § 257.105(f)(12).

(12) The design and construction plans, and any revisions of them, specified under § 257.105(f)(13).

(g) *Operating criteria.* The owner or operator of a CCR unit subject to this subpart must place the following information on the owner or operator's CCR Web site:

(1) The CCR fugitive dust control plan, or any subsequent amendment of the plan, specified under § 257.105(g)(1) except that only the most recent plan must be maintained on the CCR Web site irrespective of the time requirement specified in paragraph (c) of this section.

(2) The annual CCR fugitive dust control report specified under § 257.105(g)(2).

(3) The initial and periodic run-on and run-off control system plans specified under § 257.105(g)(3).

(4) The initial and periodic inflow design flood control system plans specified under § 257.105(g)(4).

(5) The periodic inspection reports specified under § 257.105(g)(6).

(6) The documentation detailing the corrective measures taken to remedy the deficiency or release specified under § 257.105(g)(7).

(7) The periodic inspection reports specified under § 257.105(g)(9).

(h) *Groundwater monitoring and corrective action.* The owner or operator of a CCR unit subject to this subpart must place the following information on the owner or operator's CCR Web site:

(1) The annual groundwater monitoring and corrective action report specified under § 257.105(h)(1).

(2) The groundwater monitoring system certification specified under § 257.105(h)(3).

(3) The selection of a statistical method certification specified under § 257.105(h)(4).

(4) The notification that an assessment monitoring programs has been established specified under § 257.105(h)(5).

(5) The notification that the CCR unit is returning to a detection monitoring program specified under § 257.105(h)(7).

(6) The notification that one or more constituents in appendix IV to this part have been detected at statistically significant levels above the groundwater protection standard and the notifications to land owners specified under § 257.105(h)(8).

(7) The notification that an assessment of corrective measures has been initiated specified under § 257.105(h)(9).

(8) The assessment of corrective measures specified under § 257.105(h)(10).

(9) The semiannual reports describing the progress in selecting and designing remedy and the selection of remedy report specified under § 257.105(h)(12), except that the selection of the remedy report must be maintained until the remedy has been completed.

(10) The notification that the remedy has been completed specified under § 257.105(h)(13).

(i) *Closure and post-closure care.* The owner or operator of a CCR unit subject to this subpart must place the following information on the owner or operator's CCR Web site:

(1) The notification of intent to initiate closure of the CCR unit specified under § 257.105(i)(1).

(2) The annual progress reports of closure implementation specified under § 257.105(i)(2).

(3) The notification of closure completion specified under § 257.105(i)(3).

(4) The written closure plan, and any amendment of the plan, specified under § 257.105(i)(4).

(5) The demonstration(s) for a time extension for initiating closure specified under § 257.105(i)(5).

(6) The demonstration(s) for a time extension for completing closure specified under § 257.105(i)(6).

(7) The notification of intent to close a CCR unit specified under § 257.105(i)(7).

(8) The notification of completion of closure of a CCR unit specified under § 257.105(i)(8).

(9) The notification recording a notation on the deed as required by § 257.105(i)(9).

(10) The notification of intent to comply with the alternative closure requirements as required by § 257.105(i)(10).

(11) The annual progress reports under the alternative closure requirements as required by § 257.105(i)(11).

(12) The written post-closure plan, and any amendment of the plan, specified under § 257.105(i)(12).

(13) The notification of completion of post-closure care specified under § 257.105(i)(13).

(j) *Retrofit criteria.* The owner or operator of a CCR unit subject to this subpart must place the following information on the owner or operator's CCR Web site:

(1) The written retrofit plan, and any amendment of the plan, specified under § 257.105(j)(1).

(2) The notification of intent to comply with the alternative retrofit requirements as required by § 257.105(j)(2).

(3) The annual progress reports under the alternative retrofit requirements as required by § 257.105(j)(3).

(4) The demonstration(s) for a time extension for completing retrofit activities specified under § 257.105(j)(4).

(5) The notification of intent to retrofit a CCR unit specified under § 257.105(j)(5).

(6) The notification of completion of retrofit activities specified under § 257.105(j)(6).

■ 5. Amend part 257 by adding "Appendix III to Part 257" and "Appendix IV to Part 257" to read as follows:

**Appendix III to Part 257—Constituents for Detection Monitoring**

| Common name [1] |
|---|
| Boron |
| Calcium |
| Chloride |
| Fluoride |
| pH |
| Sulfate |
| Total Dissolved Solids (TDS) |

[1] Common names are those widely used in government regulations, scientific publications, and commerce; synonyms exist for many chemicals.

**Appendix IV to Part 257—Constituents for Assessment Monitoring**

| Common name [1] |
|---|
| Antimony |
| Arsenic |
| Barium |
| Beryllium |
| Cadmium |
| Chromium |
| Cobalt |
| Fluoride |
| Lead |
| Lithium |
| Mercury |
| Molybdenum |
| Selenium |
| Thallium |
| Radium 226 and 228 combined |

[1] Common names are those widely used in government regulations, scientific publications, and commerce; synonyms exist for many chemicals.

## PART 261—IDENTIFICATION AND LISTING OF HAZARDOUS WASTE

■ 6. The authority citation for part 261 continues to read as follows:

**Authority:** 42 U.S.C. 6905, 6912(a), 6921, 6922, 6924(y) and 6938.

■ 7. Section 261.4 is amended by revising paragraph (b)(4) to read as follows:

**§ 261.4 Exclusions.**

* * * * *

(b) * * *

(4)(i) Fly ash waste, bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels, except as provided by § 266.112 of this chapter for facilities that burn or process hazardous waste.

(ii) The following wastes generated primarily from processes that support the combustion of coal or other fossil fuels that are co-disposed with the wastes in paragraph (b)(4)(i) of this section, except as provided by § 266.112 of this chapter for facilities that burn or process hazardous waste:

(A) *Coal pile run-off.* For purposes of paragraph (b)(4) of this section, coal pile run-off means any precipitation that drains off coal piles.

(B) *Boiler cleaning solutions.* For purposes of paragraph (b)(4) of this section, boiler cleaning solutions means water solutions and chemical solutions used to clean the fire-side and water-side of the boiler.

(C) *Boiler blowdown.* For purposes of paragraph (b)(4) of this section, boiler blowdown means water purged from boilers used to generate steam.

(D) *Process water treatment and demineralizer regeneration wastes.* For purposes of paragraph (b)(4) of this section, process water treatment and demineralizer regeneration wastes means sludges, rinses, and spent resins generated from processes to remove dissolved gases, suspended solids, and dissolved chemical salts from combustion system process water.

(E) *Cooling tower blowdown.* For purposes of paragraph (b)(4) of this section, cooling tower blowdown means water purged from a closed cycle cooling system. Closed cycle cooling systems include cooling towers, cooling ponds, or spray canals.

(F) *Air heater and precipitator washes.* For purposes of paragraph (b)(4) of this section, air heater and precipitator washes means wastes from cleaning air preheaters and electrostatic precipitators.

(G) *Effluents from floor and yard drains and sumps.* For purposes of paragraph (b)(4) of this section, effluents from floor and yard drains and sumps means wastewaters, such as wash water, collected by or from floor drains, equipment drains, and sumps located inside the power plant building; and wastewaters, such as rain runoff, collected by yard drains and sumps located outside the power plant building.

(H) *Wastewater treatment sludges.* For purposes of paragraph (b)(4) of this section, wastewater treatment sludges refers to sludges generated from the treatment of wastewaters specified in paragraphs (b)(4)(ii)(A) through (F) of this section.

* * * * *

[FR Doc. 2015–00257 Filed 4–16–15; 8:45 am]

BILLING CODE 6560–50–P

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**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**:
(jovick@southernco.com)

In the Matter of an
Application for Permit by:

Gulf Power Company
James O. Vick
Director of Environmental Affairs
One Energy Place
Pensacola, Florida 32520

Jackson County
Scholz Electric Generating Plant
NPDES Permit No. FL0002283
PA File No. FL0002283-005-IW1S

NOTICE OF DRAFT PERMIT

The Department of Environmental Protection gives notice of its preparation of a draft permit (copy attached) for the proposed project as detailed in the application specified above, for the reasons stated below.

The applicant, Gulf Power Company, applied on March 20, 2015, to the Department of Environmental Protection for a permit to operate wastewater treatment and effluent disposal facilities at the Scholz Electric Generating Plant in Jackson County, Florida. The discharge consists of non-contact once-through condenser cooling water (OTCW) to the on-site discharge canal, and thence to the Apalachicola River, a Class III fresh water. All other industrial and domestic wastewater streams discharge into the on-site ash pond. Intermittent overflow from the ash pond discharges to the discharge canal. The coal ash pond is scheduled to be closed during this permit cycle.

The Department has permitting jurisdiction under Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code. The project is not exempt from permitting procedures. The Department has determined that a wastewater permit is required for the proposed work.

Based upon the application and supplemental information, the Department has determined that the applicant has provided reasonable assurance that the above describe wastewater project complies with the applicable provisions of Chapter 403 of the Florida Statutes and Title 62 of the Florida Administrative Code.

The Department intends to issue the above referenced permit based on its belief that reasonable assurances have been provided to indicate that the proposed project will not adversely impact water quality and the proposed project will comply with the appropriate provisions of the Florida Administrative Code Rule 62-620 as long as all of the conditions in the attached permit are adhered to.

Under Section 403.815, Florida Statutes, and Rule 62-620.550, Florida Administrative Code, you (the applicant) are required to publish at your own expense the enclosed Notice of Draft Permit and



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Request for Public Comment. The notice must be published one time only within 30 days of receipt of this draft permit in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, Florida Statutes, in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used should be one with significant circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant must provide proof of publication to the Department of Environmental Protection, Bob Martinez Center, Industrial Wastewater Program, 2600 Blair Stone Road, Mail Station 3545, Tallahassee, Florida 32399-2400, within two weeks of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

The Department intends to issue the permit with the attached conditions unless as a result of public comment appropriate changes are made.

Any interested person may submit written comments on the Department's proposed permitting decision or may submit a written request for a public meeting to Mr. Marc Harris, P.E., Department of Environmental Protection, Bob Martinez Center, Industrial Wastewater Program, 2600 Blair Stone Road, Mail Station 3545, Tallahassee, Florida 32399-2400 in accordance with Rule 62-620.555, Florida Administrative Code. The comments or request for a public meeting must contain the information set forth below and must be received in the Department's Industrial Wastewater Program. Comments from the permit applicant and the persons listed below must be received within 30 days of receipt of this draft permit. Comments submitted by other persons must be received within 30 days of publication of the public notice. Failure to submit comments or request a public meeting within this time period shall constitute a waiver of any right such person may have to submit comments or request a public meeting under Rule 62-620.555, Florida Administrative Code.

The comments or request for a public meeting must contain the following information:

(a) The commenter's name, address, and telephone number; the applicant's name and address; the Department permit file number; and the county in which the project is proposed;
(b) A statement of how and when notice of the Department's action or proposed action was received;
(c) A statement of the facts the Department should consider in making the final decision;
(d) A statement of which rules or statutes require reversal or modification of the Department's action or proposed action; and
(e) If desired, a request that a public meeting be scheduled including a statement of the nature of the issues proposed to be raised at the meeting.

If a public meeting is scheduled, the public comment period is extended until the close of the public meeting. However, the Department may not always grant a request for a public meeting. Therefore, written comments should be submitted within 30 days of publication of this notice, even if a public meeting is requested.

If a public meeting is held, any person may submit oral or written statements and data at the public meeting on the Department's proposed action. As a result of significant public comment, the Department's final action may be different from the position taken by it in this draft permit.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Elsa A. Potts

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.

Thirley Shields 08-24-15
Clerk 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 08-24-15 to the listed persons.

Thirley Shields 08-24-15
Name 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)
Chairman, Board of Jackson County Commissioners (kstephens@jacksoncountyfl.com)
FWC, Conservation Planing Services (fwcconservationplanningservices@myfwc.com)
Jim Valade, U.S. Fish and Wildlife Service (jim_valade@fws.gov)
Florida Department of Economic Opportunity, State Land Planning Agency (DCPPermits@deo.myflorida.com)
Florida Department of State, Bureau of Historic Preservation (compliancepermits@dos.state.fl.us)
U.S. Army Corps of Engineers (james.j.mcadams@usace.army.mil)
Mike Markey, P.G., Gulf Power Co. (rmmarkey@southernco.com)
Robert Jernigan, Gulf Power Co. (rjjernig@southernco.com)
Brandon Smith, Gulf Power Co. (blsmith@southernco.com)
Bill Evans, P.E., DEP Pensacola (bill.evans@dep.state.fl.us)
Kim Allen, P.E., DEP Pensacola (kim.allen@dep.state.fl.us)
Dawn Templin, P.E., DEP Pensacola (dawn.templin@dep.state.fl.us)
Nijole Wellendorf, DEP Tallahassee (nijole.wellendorf@dep.state.fl.us)



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STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF DRAFT PERMIT

The Department of Environmental Protection gives notice of its preparation of a draft NPDES renewal permit (DEP File Number FL0002283-005-IW1S) to Gulf Power Company, 1460 Gulf Power Road, Sneads, Florida 32460, to operate wastewater treatment and effluent disposal facilities at the Scholz Electric Generating Plant located in Jackson County, Florida. The discharge consists of non-contact once-through condenser cooling water (OTCW) to the on-site discharge canal, and thence to the Apalachicola River, a Class III fresh water. All other industrial and domestic wastewater streams discharge into the on-site ash pond. Intermittent overflow from the ash pond discharges to the discharge canal. The coal ash pond is scheduled to be closed during this permit cycle.

Any interested person may submit written comments on the Department's draft permit or may submit a written request for a public meeting to the Department of Environmental Protection, Bob Martinez Center, Industrial Wastewater Program, 2600 Blair Stone Road, Mail Station 3545, Tallahassee, Florida 32399-2400, Attention: Mr. Marc Harris, P.E., in accordance with Rule 62-620.555, Florida Administrative Code (F.A.C.). The comments or request for a public meeting must contain the information set forth below and must be received in the Department's Industrial Wastewater Program within 30 days of publication of this notice. Failure to submit comments or request a public meeting within this time period shall constitute a waiver of any right such person may have to submit comments or request a public meeting under Rule 62-620.555, F.A.C.

The comments or request for a public meeting must contain the following information:

(a) The commenter's name, address, and telephone number; the applicant's name and address; the Department permit file number; and the county in which the project is proposed;
(b) A statement of how and when notice of the Department's action or proposed action was received;
(c) A statement of the facts the Department should consider in making the final decision;
(d) A statement of which rules or statutes require reversal or modification of the Department's action or proposed action; and
(e) If desired, a request that a public meeting be scheduled including a statement of the nature of the issues proposed to be raised at the meeting.

If a public meeting is scheduled, the public comment period is extended until the close of the public meeting. However, the Department may not always grant a request for a public meeting. Therefore, written comments should be submitted within 30 days of publication of this notice, even if a public meeting is requested.

If a public meeting is held, any person may submit oral or written statements and data at the public meeting on the Department's proposed action. As a result of significant public comment, the Department's final action may be different from the position taken by it in this draft permit.

The permit application file and supporting data are available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at the Florida Department of Environmental Protection, Bob Martinez Center, Industrial Wastewater Program, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, telephone (850) 245-8589 and at the Department's Northwest District Office located at 160 W. Government Street, Suite 308, Pensacola, Florida 32502, Phone Number: (850) 595-8300.

# STATE OF FLORIDA
# INDUSTRIAL WASTEWATER FACILITY PERMIT

**PERMITTEE:**
Gulf Power Company

**RESPONSIBLE OFFICIAL:**
Mr. James O. Vick
Director of Environmental Affairs
One Energy Place
Pensacola, Florida 32520
(850) 444-6429

**PERMIT NUMBER:** FL0002283-005 (Major)
**FILE NUMBER:** FL0002283-005-IW1S
**ISSUANCE DATE:** **DRAFT**
**EXPIRATION DATE:** **DRAFT**

**FACILITY:**

Scholz Electric Generating Plant
1460 Gulf Power Road
Sneads, FL 32460
Jackson County

Latitude: 30° 40' 11.55" N Longitude: 84° 53' 15.76" 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:**
This facility consists of two coal fired steam electric generating units (Units 1 and 2) with a total nameplate rating of 80 megawatts (MW), and a gross generation capacity of 98 MW.

**WASTEWATER TREATMENT:**
Non-contact once-through condenser cooling water (OTCW) discharges with chlorination to the on-site discharge canal, and thence to the Apalachicola River, a Class III fresh water. All other industrial and domestic wastewater streams discharge into the on-site ash pond. Discharges to the on-site ash pond consist of low volume wastes (LVW) (i.e. ash sluice water, water softener regeneration wastewater, boiler blowdown and air preheater wash), auxiliary equipment cooling water, coal pile runoff, yard sump runoff, and treated domestic wastewater. Domestic wastewater receives secondary treatment in a package treatment plant prior to discharging to the ash pond. Intermittent overflow from the ash pond discharges to the on-site discharge canal, and thence to the Apalachicola River. The coal ash pond is scheduled to be closed during this permit cycle.

**EFFLUENT DISPOSAL:**

**Surface Water Discharge D-001:** An existing 129.6 MGD maximum permitted discharge to the Apalachicola River, Class III Fresh Waters, (WBID No. 375G). The point of discharge is located approximately at latitude 30°39' 59" N, longitude 84°53' 12" W.

**Internal Outfall I-012:** An existing permitted intermittent discharge to the discharge canal from the ash pond.

**Internal Outfall I-013:** An existing permitted discharge to the on-site ash pond.

**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.

## 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 and intermittent ash pond overflow from **Outfall D-001(COMBINED PLANT DISCHARGE)** to the Apalachicola River. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.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 | Daily; 24 hours | Calculated | INT-1 | |
| Flow | MGD | Max | Report | Daily Maximum | Daily; 24 hours | Calculated | EFF-2 | |
| Temperature (F), Water (Intake) | Deg F | Max<br>Max | Report<br>Report | Daily Maximum<br>Monthly Average | 4 Days/Week | Meter | INT-1 | |
| Temperature (F), Water (Discharge) | Deg F | Max<br>Max | Report<br>Report | Daily Maximum<br>Monthly Average | 4 Days/Week | Meter | EFF-1 | See I.A.6 |
| pH | s.u. | Min<br>Max | 6.0<br>8.5 | Daily Minimum<br>Daily Maximum | Weekly | Grab | EFF-2 | |
| Oil and Grease | mg/L | Max<br>Max | 5.0<br>5.0 | Daily Maximum<br>Monthly Average | Quarterly | Grab | EFF-2 | |
| Chlorine, Total Residual | mg/L | Max<br>Max | 0.01<br>0.01 | Daily Maximum<br>Monthly Average | Weekly | Multiple Grabs[1] | EFF-2 | See I.A.7 |
| Chlorination Duration | min | Max | 120 | Daily Maximum | Weekly | Calculated | EFF-2 | |
| Aluminum, Total Recoverable | mg/L | Max | Report | Single Sample | Annually | 24-hr TPC | EFF-2, INT-1 | |
| Arsenic, Total | ug/L | Max | 50<br>50 | Daily Maximum<br>Monthly Average | Annually | 24-hr TPC | EFF-2, INT-1 | |
| Beryllium, Total Recoverable | ug/L | Max | Report | Single Sample | Annually | 24-hr TPC | EFF-2, INT-1 | |
| Cadmium, Total Recoverable | ug/L | Max | See I.A.4 | Single Sample | Annually | 24-hr TPC | EFF-2, INT-1 | See I.A.4 and I.A.5 |
| Chromium, Total Recoverable | ug/L | Max | Report | Single Sample | Annually | 24-hr TPC | EFF-2, INT-1 | |
| Copper, Total Recoverable | ug/L | Max | See I.A.4 | Single Sample | Annually | 24-hr TPC | EFF-2, INT-1 | See I.A.4 and I.A.5 |
| Iron, Total Recoverable | mg/L | Max<br>Max | 1.0<br>1.0 | Daily Maximum<br>Monthly Average | Annually | 24-hr TPC | EFF-2, INT-1 | See I.A.5 |
| Lead, Total Recoverable | ug/L | Max | See I.A.4 | Single Sample | Annually | 24-hr TPC | EFF-2, INT-1 | See I.A.4 and I.A.5 |
| Mercury, Total Recoverable | ug/L | Max | Report | Daily Maximum | Annually | 24-hr TPC | EFF-2, INT-1 | |
| Nickel, Total Recoverable | ug/L | Max | See I.A.4 | Single Sample | Annually | 24-hr TPC | EFF-2, INT-1 | See I.A.4 and I.A.5 |
| Selenium, Total Recoverable | ug/L | Max | Report | Single Sample | Annually | 24-hr TPC | EFF-2, INT-1 | |
| Vanadium, Total Recoverable | mg/L | Max | Report | Single Sample | Annually | 24-hr TPC | EFF-2, INT-1 | |
| Zinc, Total Recoverable | ug/L | Max | See I.A.4 | Single Sample | Annually | 24-hr TPC | EFF-2, INT-1 | See I.A.4 and I.A.5 |
| Hardness, Total (as CaCO3) | mg/L | Max | Report | Single Sample | Annually | 24-hr TPC | EFF-2 | See I.A.4 |

[1] Multiple grabs for TRC shall consist of grab samples collected at approximately the beginning of the period of expected chlorine discharge and once every 15 minutes thereafter until the end of the period of chlorine discharge.



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| | | | Effluent Limitations | | Monitoring Requirements | | | |
|---|---|---|---|---|---|---|---|---|
| Parameter | Units | Max/ Min | Limit | Statistical Basis | Frequency of Analysis | Sample Type | Monitoring Site Number | Notes |
| Nitrogen, Ammonia, Total (as N) | mg/L | Max | Report | Single Sample | Quarterly | Grab | EFF-2 | |
| Nitrogen, Kjeldahl, Total (as N) | mg/L | Max | Report | Single Sample | Quarterly | Grab | EFF-2 | |
| Nitrogen, Nitrate, Total (as N) | mg/L | Max | Report | Single Sample | Quarterly | Grab | EFF-2 | |
| Nitrogen, Nitrite, Total (as N) | mg/L | Max | Report | Single Sample | Quarterly | Grab | EFF-2 | |
| Nitrogen, Total | mg/L | Max | Report | Single Sample | Quarterly | Grab | EFF-2 | |
| Nitrogen, Total | lb/year | Max | Report | Annual Total | Annually | Calculated | INT-1 EFF-2 | See I.A.15 |
| Nitrogen, Total (Net) | lb/year | Max | Report | Annual Total | Annually | Calculated | EFF-2 | See I.A.15 |
| Phosphate, Ortho (as PO4) | mg/L | Max | Report | Single Sample | Quarterly | Grab | EFF-2 | |
| Phosphorus, Total (as P) | mg/L | Max | Report | Single Sample | Quarterly | Grab | EFF-2 | |
| Phosphorus, Total (as P) | lb/year | Max | Report | Annual Total | Annually | Calculated | INT-1 EFF-2 | See I.A.15 |
| Phosphorus, Total (as P) (Net) | lb/year | Max | Report | Annual Total | Annually | Calculated | EFF-2 | See I.A.15 |
| Chronic Whole Effluent Toxicity, 7-Day IC25 (Ceriodaphnia dubia) | percent | Min | 100 | Single Sample | Quarterly[2] | 24-hr TPC | EFF-2 | See I.A.14 |
| Chronic Whole Effluent Toxicity, 7-Day IC25 (Pimephales promelas) | percent | Min | 100 | Single Sample | Quarterly[2] | 24-hr TPC | EFF-2 | 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 |
|---|---|
| EFF-2 | In the discharge canal 200 feet downstream from the ash pond discharge prior to the confluence of the discharge canal and the Apalachicola River. |
| INT-1 | At the condenser inlet. |
| EFF-1 | At condenser outlet. |

3. 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)]*

4. The limit for "Copper, Total Recoverable", "Cadmium, Total Recoverable", "Lead, Total Recoverable", "Nickel, Total Recoverable", and "Zinc, Total Recoverable" shall be calculated using the following equation(s):

$Cu \leq e^{(0.8545[\ln H]-1.702)}$
$Cd \leq e^{(0.7409[\ln H]-4.719)}$
$Pb \leq e^{(1.273[\ln H]-4.705)}$
$Ni \leq e^{(0.846[\ln H]+0.0584)}$
$Zn \leq e^{(0.8473[\ln H]+0.884)}$

[2] Whole effluent toxicity testing shall be completed during the period of chlorination of the once-through cooling water.

Total hardness shall be measured at the time of the effluent sample. The "ln H" means the natural logarithm of total hardness expressed as mg/L of $CaCO_3$. For metals criteria involving equations with hardness, the hardness shall be set at 25 mg/L if actual hardness is <25 mg/L and set at 400 mg/L if actual hardness is >400 mg/L.

The measured effluent value shall be recorded on the DMR in the parameter row for "Copper, Total Recoverable", "Cadmium, Total Recoverable", "Lead, Total Recoverable", "Nickel, Total Recoverable", and "Zinc, Total Recoverable" (effluent). The calculated effluent limit shall be recorded on the DMR in the parameter row for "Copper, Total Recoverable", "Cadmium, Total Recoverable", "Lead, Total Recoverable", "Nickel, Total Recoverable", and "Zinc, Total Recoverable" (calculated limit). Compliance with the effluent limitation is determined by calculating the difference between the measured effluent value and the calculated. The compliance value shall be recorded on the DMR in the parameter row for "Copper, Total Recoverable", "Cadmium, Total Recoverable", "Lead, Total Recoverable", "Nickel, Total Recoverable", and "Zinc, Total Recoverable" (effluent minus calculated limit). The compliance value shall not exceed 0.00. *[62-302.530(23), 62-302.530(15), and 62-302.530(39)]*

5. The actual limit shall be the water quality standard set in Rule 62-302.530, F.A.C., for Class III fresh water or the concentration of the intake cooling water, whichever is greater. If the Outfall D-001 composite sample exceeds the intake concentration, and the intake concentration exceeds the water quality standard, a minimum of five (5) additional sub-samples shall be measured from the original intake and outfall composites and a "student t-test" shall be run on these additional sub-sample comparing discharge concentrations with intake concentrations; unless the discharge concentration exceeds the intake concentration at the 95% confidence level, the facility shall be in compliance with the limit.

6. Discharge from Outfall D-001 is subject to the requirements of Rule 62-302.520(1), F.A.C.

7. Limitations and monitoring requirements for total residual chlorine are not applicable for time periods in which once-through condenser cooling water is not chlorinated.

8. Discharge of uncontaminated stormwater; intake screen backwash water, turbine oil cooling water, and hydrogen cooler water is permitted without limitations or monitoring requirements except that there shall be no discharge of floating oil.

9. The permittee shall maintain the current intake through-screen velocity such that the existing maximum velocity is not exceeded. *[C.W.A. 316(b)]*

10. The permittee shall maintain current travelling screen practices at Units 1 and 2 so as to assure that the screens are cycled twice during each 24 hours of continuous operation unless precluded by repair/maintenance requirements.

11. Fish, shellfish, and other aquatic organisms collected from or trapped on the intake screens shall be returned or relocated to their natural habitat in such a manner to minimize stress or mortality. Material collected on the intake screens shall be removed and disposed of in accordance with all the existing Federal, state and or local laws and regulations that apply to waste disposal. Such material shall not be returned to the receiving waters. *[C.W.A. 316(b)]*

12. If the facility resumes the use of once-through cooling water such that the requirements of 40 CFR 125.91 are applicable, the permittee shall complete all studies and gather all information required under 40 CFR 122.21(r) necessary to establish impingement mortality and entrainment BTA requirements and shall submit the required information with the permit renewal application. *[C.W.A. 316 (b)]*

13. 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)]*

14. The permittee shall comply with the following requirements to evaluate chronic whole effluent toxicity of the discharge from Outfall D-001.

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 three months, the first starting within 60 days of the issuance date of this permit and lasting for the duration of this permit.
   (2) Upon completion of four consecutive, 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 for a reduction in monitoring frequency to once every six months. The request shall include a summary of the data and the complete bioassay laboratory reports for each test used to demonstrate compliance. The Department shall act on the request within 45 days of receipt. Reductions in monitoring shall only become effective upon the Department's written confirmation that the facility has completed four consecutive valid routine tests that demonstrate compliance with the effluent limitation in 14.a.(1) above.
   (3) If a test within the sequence of the four is deemed invalid based on the acceptance criteria in EPA-821-R-02-013, 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 valid tests for the purpose of evaluating the reduction of monitoring frequency.

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-02-013, 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 a daphnid, **Ceriodaphnia dubia**, Survival and Reproduction Test and a fathead minnow, **Pimephales promelas**, Larval Survival and Growth Test, 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 Freshwater Organisms**, 4th Edition, EPA-821-R-02-013. 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 shall be moderately hard water as described in EPA-821-R-02-013, Section 7.2.3.

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 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-02-013, Section



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13.12 (**Ceriodaphnia dubia**) and Section 11.11 (**Pimephales promelas**). 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 test 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-02-013, 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-02-013, 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-02-013, 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
Northwest District Office
160 W. Government Street, Suite 308
Pensacola, Florida 32502-5794

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-02-013.

(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 within 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



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14.b.(1). If a routine test is invalid according to the acceptance criteria in EPA-821-R-02-013, 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. The annual mass loads of total nitrogen and total phosphorus shall be calculated as follows:

**AL** (Lbs/year) = **Flow** (MG/year) x **TN or TP** (mg/L) x 8.34 (L-Lbs/MG-mg)

Where:

**AL** =Annual mass load of total nitrogen or total phosphorus at EFF-2; (Lbs/year)

**Flow** =Total volume of effluent discharged from the point source in a given year at EFF-2; (million gallons (MG)). This flow volume shall include all internal flows discharged to the discharge canal.

**TN** = Concentration of TN collected at EFF-2; (mg/L)

**TP** = Concentration of TP collected at EFF-2; (mg/L)

The same formula shall be used to calculate the lb/year of TN and TP at the intake (INT-1) as shown below.

**$AL_1$** (Lbs/year) = **$Flow_1$** (MG/year) x **$TN_1$ or $TP_1$** (mg/L) x 8.34 (L-Lbs/MG-mg)

Where:

**$AL_1$** =Annual mass load of total nitrogen or total phosphorus at INT-1; (Lbs/year)

**$Flow_1$** =Total volume of influent withdrawn from the intake canal in a given year at INT-1; (million gallons (MG))

**$TN_1$** = Concentration of TN collected at INT-1; (mg/L)

**$TP_1$** = Concentration of TP collected at INT-1; (mg/L)

The net TN and TP loadings to surface waters at D-001 shall be calculated as the AL at EFF-2 less $AL_1$ at INT-1.

## 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 low volume wastes, auxiliary equipment cooling water, coal pile runoff, yard sump runoff, and treated domestic wastewater from **Internal Outfall I-012 (ASH POND DISCHARGE)** to the



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discharge canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.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 Average | Weekly | Calculated | OUI-3 | |
| Solids, Total Suspended | mg/L | Max<br>Max | 30.0<br>100.0 | Monthly Average<br>Daily Maximum | Weekly | 24-hr TPC | OUI-3 | |
| Oil and Grease | mg/L | Max<br>Max | 15.0<br>20.0 | Monthly Average<br>Daily Maximum | Bi-weekly; every 2 weeks | Grab | OUI-3 | |
| pH | s.u. | Min<br>Max | 6.0<br>9.0 | Daily Minimum<br>Daily Maximum | Weekly | Grab | OUI-3 | |
| Nickel, Total Recoverable | ug/L | Max | Report | Instantaneous Maximum | Annually | Grab | OUI-3 | |

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 |
|---|---|
| OUI-3 | The point of discharge at the ash pond discharge weir. |

3. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge domestic treatment plant wastewater from **Internal Outfall I-013 (DOMESTIC WASTEWATER TREATMENT PLANT EFFLUENT)** to the ash pond. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

| | | | Effluent Limitations | | Monitoring Requirements | | | |
|---|---|---|---|---|---|---|---|---|
| Parameter | Units | Max/ Min | Limit | Statistical Basis | Frequency of Analysis | Sample Type | Monitoring Site Number | Notes |
| Flow | MGD | Max<br>Max | Report<br>Report | Daily Maximum<br>Monthly Average | Weekly | Meter | OUI-4 | |
| Biochemical Oxygen Demand-5 | mg/L | Max<br>Max | 25.0<br>60.0 | Monthly Average<br>Daily Maximum | Quarterly | Grab | OUI-4 | |
| Solids, Total Suspended | mg/L | Max<br>Max | 30.0<br>60.0 | Monthly Average<br>Daily Maximum | Quarterly | Grab | OUI-4 | |
| Coliform, Fecal | #/100mL | Max | See I.B.6 | | Quarterly | Grab | OUI-4 | See I.B.6 |

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 |
|---|---|
| OUI-4 | The point of discharge at the wastewater treatment outlet box. |

5. Wastewater treatment plant effluent shall be continuously chlorinated and 0.5 mg/l chlorine residual shall be maintained in the contact chamber for 15 minutes prior to discharge.

6. The arithmetic mean of the monthly fecal coliform values collected during an annual period, as described in subparagraph 62-600.740(1)(a)1., F.A.C., shall not exceed 200 per 100 mL of reclaimed water sample. The



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geometric mean of the fecal coliform values for a minimum of 10 samples of reclaimed water, each collected on a separate day during a period of 30 consecutive days (monthly), shall not exceed 200 per 100 mL of sample. No more than 10 percent of the samples collected (the 90th percentile) during a period of 30 consecutive days shall exceed 400 fecal Coliform values per 100 mL of sample. Any one sample shall not exceed 800 fecal coliform values per 100 mL of sample. *Note:* To report the value of the sample that corresponds to the 90th percentile value, list the fecal Coliform values obtained during the month in ascending order. Report the value of the sample that corresponds to the 90th percentile (multiply the number of samples by 0.9). For example, for 30 samples, report the corresponding fecal number for the 27th value of ascending order.

*[62-600.440(4)(c)]*

**C. 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 quantification 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 28 |



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| | | |
|---|---|---|
| | April 1 - June 30<br>July 1 - September 30<br>October 1 - December 31 | July 28<br>October 28<br>January 28 |
| Semiannual | January 1 - June 30<br>July 1 - December 30 | July 28<br>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 Northwest District Office at the address specified below:

   Florida Department of Environmental Protection
   Northwest District Office
   160 W. Government Street, Suite 308
   Pensacola, Florida 32502-5794

   Phone Number - (850) 595-8300
   FAX Number - (850) 595-8417 (All FAX copies shall be followed by original copies.)

   *[62-620.305]*

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. Any bypass of the treatment facility which is not included in the monitoring specified in Sections I.A and I.B., is to be monitored for flow and all other required parameters. For parameters other than flow, at least one grab sample per day shall be monitored. Daily flow shall be monitored or estimated, as appropriate, to obtain reportable data. All monitoring results shall be reported on the appropriate DMR.

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

   a. Department-issued permits governing soil thermal treatment (Chapter 62-713, F.A.C.) or Department-approved landfills provided the PCB concentrations meet the Florida landfill's permitted limit when concentrations are less than 50 ppm; or

   b. 40 CFR 761 when concentrations are greater than or equal to 50 ppm.



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*[40 CFR Part 423.12(b)(2)]*

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 use of herbicides if used in accordance with labeled instructions and any applicable State permit. In the event the permittee proposes to use water treatment chemicals, biocides, corrosion inhibitors, or additives not authorized in this permit, or not previously reported to the Department, that ultimately may be released to waters of the State, the permittee shall notify the Department in writing a minimum of thirty (30) days prior to instituting the use of such product. The product shall not be used prior to a determination by the Department that a permit revision is not required or prior to Department approval. Such notification shall include:

   a. Name and general composition of biocide or chemical

   b. Frequencies of use

   c. Quantities to be used

   d. Proposed effluent concentrations

   e. Acute and/or chronic toxicity data (laboratory reports shall be prepared, depending on the test type, according to Section 12 of EPA document no. EPA-821-R-02-012 entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, Section 10 of EPA document no. EPA-821-R-02-013 entitled, Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms or Section 10 of EPA document no. EPA-821-R-02-014 entitled, Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms, or most current addition)

   f. Product data sheet

   g. Product label

   A revision to this permit is not necessary for use of products equivalent to those authorized in this permit provided the equivalent products consist of the same active ingredients and the product is applied at the same location with the same or lower concentrations of the active ingredients at the outfall. The permittee is responsible for maintaining documentation on-site which demonstrates equivalency of any new water treatment products from another vendor or manufacturer with a different product name from those listed above.

10. Discharge of any waste resulting from the combustion of toxic, hazardous, or metal cleaning wastes to any waste stream which ultimately discharges to waters of the State is prohibited, unless specifically authorized elsewhere in this permit. The discharge of plant ash transport water, resulting from the combustion of on-specification used oil as authorized under the Resource Conservation and Recovery Act and 40 CFR Part 266, via the ash pond shall be an authorized discharge of this permit.

11. Metals concentrations shall be reported and expressed as the total recoverable fraction. *[62-302.500(2)(d) and 62-620.620(2)(c)1, F.A.C.]*

12. The permittee shall not store coal, soil, or other similar erodible materials in a manner in which runoff is uncontrolled, nor shall construction activities be conducted in a manner which produces uncontrolled runoff unless such uncontrolled runoff has been specifically approved by the Department. "Uncontrolled" shall mean without sedimentation basin or other controls approved by the Department.

13. The permittee is authorized to utilize the following water treatment chemicals and biocides, or their equivalents, in the Units 1 and 2 cooling water systems and other wastewater streams:

| Chemical Name | System Used | Chemical Purpose |
|---|---|---|
| Ammonium Hydroxide | Boiler Water System | pH Control |
| Hydrazine | Boiler Water System | Oxygen Scavenger |
| Calcium hypochlorite | Once-through cooling water system | Biocide |



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14. 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.4, and made available to Department staff upon request. *[62-620.200(26)(a) & (b)]*

## II. SLUDGE AND RESIDUALS MANAGEMENT REQUIREMENTS

### A. Domestic Residuals Management Requirements

1. The method of residuals use or disposal by this facility is transport to a residuals management facility (RMF). Transportation of the residuals to an alternative RMF does not require a permit modification. However, use of an alternative RMF requires the submittal of a copy of the agreement pursuant to Rule 62-640.880(1)(c), F.A.C., along with a written notification to the Department at least 30 days before transport of the residuals. *[62-620.320(6), 62-640.880(1)]*

2. The permittee shall be responsible for proper management or disposal of its residuals. *[62-640.300(5)]*

3. The permittee shall not be held responsible for treatment, management, use, or land application violations that occur after its residuals have been accepted by a permitted RMF which the source facility has an agreement with in accordance with Rule 62-640.880(1)(c), F.A.C., for further treatment, management, use or land application. *[62-640.300(5)]*

4. Disposal of residuals, septage, and other solids in a solid waste landfill, or disposal by placement on land for purposes other than soil conditioning or fertilization, such as at a monofill, surface impoundment, waste pile, or dedicated site, shall be in accordance with Chapter 62-701, F.A.C. *[62-640.100(6)(k)3 & 4]*

5. The permittee shall keep hauling records to track the transport of its residuals to the RMF. The hauling records shall contain the following information:

| Source Facility | Residuals Management Facility |
|---|---|
| 1. Date and Time Shipped | 1. Date and Time Received |
| 2. Amount of Residuals Shipped | 2. Amount of Residuals Received |
| 3. Degree of Treatment (if applicable) | 3. Name and ID Number of Source Facility |
| 4. Name and ID Number of Residuals Management Facility or Treatment Facility | 4. Signature of Hauler |
| 5. Signature of Responsible Party at Source Facility | 5. Signature of Responsible Party at Residuals Management Facility |
| 6. Signature of Hauler and Name of Hauling Firm | |

    These records shall be kept for five years and shall be made available for inspection upon request by the Department. A copy of the hauling records information maintained by the source facility shall be provided upon delivery of the residuals to the residuals management facility or treatment facility. The permittee shall report to the Department within 24 hours of discovery any discrepancy in the quantity of residuals leaving the source facility and arriving at the residuals management facility or treatment facility. *[62-640.880(4)]*

6. Storage of residuals or other solids at the permitted facility shall require prior written notification to the Department if the storage lasts longer than 30 days. *[62-640.300(4)]*

**B. Industrial Sludge Management Requirements**

1. The permittee shall be responsible for proper treatment, management, use or land application of its sludges.

2. Disposal of sludge in a solid waste management facility permitted by the Department shall be in accordance with the requirements of Chapter 62-701, F.A.C. Storage, transportation, and disposal of sludge/solids characterized as hazardous waste shall be in compliance with requirements of Chapter 62-730, F.A.C.

3. The permittee shall keep records of the amount of sludge disposed, transported, or incinerated. If a person other than the permittee is responsible for sludge transporting, disposal, or incineration, the permittee shall also keep the following records:

   a. Name, address and telephone number of any transporter, and any manifests or bill of lading used;

   b. Name and location of the site of disposal, treatment or incineration;

   c. Name, address, and telephone number of the entity responsible for the disposal, treatment, or incineration site.

4. The Permittee shall close the existing on-site coal ash pond during this permit cycle. Before commencing closure activities, the Permittee shall submit a closure plan for the coal ash pond to the Department's Northwest District Office and Tallahassee Industrial Wastewater Program for approval. The closure of the coal ash pond shall comply with applicable solid waste, stormwater and wastewater rules. This plan shall include a schedule and address ash dewatering, removal, and disposal; construction of ash disposal area; any re-direction of groundwater, stormwater or wastewater; removal or capping of existing outfalls; post closure groundwater monitoring; and provide reasonable assurance that discharges to surface waters will meet applicable water quality standards, and effluent guidelines in 40 CFR 423. The Permittee shall obtain all necessary permits and authorizations from the Department for the closure activities.

   No later than 90 days of completion of all ash pond closure activities, the Permittee shall submit a construction completion report to the Department's Northwest District Office Solid Waste Section and Tallahassee Industrial Wastewater Program for approval. The report shall include all applicable DEP forms such as DEP Form 62-620.910(12), Notification of Completion of Construction for Wastewater Facilities or Activities; DEP Form 62-620.910(13), Notification of Availability of Record Drawings and Final Operation and Maintenance Manuals; and DEP Form 62-701.900(2), Certification of Construction Completion of a Solid Waste Management Facility.

## III. GROUND WATER REQUIREMENTS

1. 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 62-520, F.A.C., until such time the ash impoundments/disposal areas are certified closed by the Northwest District's Solid Waste Section.

2. The following monitoring wells shall be sampled for the ground water discharge:

| Monitoring Well ID | Alternate Well Name and/or Description of Monitoring Location | Latitude | | | Longitude | | | Aquifer Monitored | WACS ID |
|---|---|---|---|---|---|---|---|---|---|
| | | ° | ' | " | ° | ' | " | | |
| MWB-205 | MW-205MD | 30 | 40 | 18 | 84 | 53 | 35.871 | Floridan | 29276 |
| MWB-2051 | MW-205S | 30 | 40 | 18 | 84 | 53 | 35 | Surficial | 29277 |
| MWC-2 | WSW-2 | 30 | 40 | 19 | 84 | 53 | 17 | Floridan | 29278 |
| MWC-203 | MW-203MD | 30 | 39 | 58.359 | 84 | 53 | 15.635 | Floridan | 29279 |
| MWC-204 | MW-204MD | 30 | 39 | 55.952 | 84 | 53 | 28.431 | Floridan | 29280 |
| MWC-210 | MW-210MD | 30 | 40 | 5.327 | 84 | 53 | 14.437 | Floridan | 29281 |
| MWC-212 | MW-212MD | 30 | 39 | 55 | 84 | 53 | 22 | Floridan | 29282 |
| MWC-2031 | MW-203S | 30 | 39 | 59 | 84 | 53 | 15 | Surficial | 29283 |
| MWI-204S | MWI-204S, Intermediate | 30 | 39 | 57 | 84 | 53 | 28 | Surficial | 29284 |
| MWI-210S | MWI-210S,Intermediate | 30 | 40 | 6 | 84 | 53 | 14 | Surficial | 29285 |
| MWP-103 | MW-103; Piezometer well | 30 | 39 | 59 | 84 | 53 | 15 | Floridan | 29784 |



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| Monitoring Well ID | Alternate Well Name and/or Description of Monitoring Location | Latitude | | | Longitude | | | Aquifer Monitored | WACS ID |
|---|---|---|---|---|---|---|---|---|---|
| | | ° | ' | " | ° | ' | " | | |
| MWP-105 | MW-105; Piezometer well | 30 | 40 | 17 | 84 | 53 | 35 | Floridan | 29785 |
| MWP-110 | MW-110A; Piezometer well | 30 | 40 | 7 | 84 | 53 | 13 | Floridan | 29786 |
| MWP-112 | MW-112; Piezometer well | 30 | 39 | 55 | 84 | 53 | 22 | Floridan | 29787 |

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

*[62-520.600]*

3. The following parameters shall be analyzed for monitoring wells MWC-203, MWB-205, and MWC-210 identified in Permit Condition III.2. Results shall be reported in accordance with Permit Condition III.18:

| Parameter | Compliance Well Limit | Units | Sample Type | Monitoring Frequency |
|---|---|---|---|---|
| Water Level Relative to NGVD | Report | ft | In Situ | Quarterly |
| pH | Report | s.u. | Grab | Quarterly |
| Specific Conductance | Report | umhos/cm | Grab | Quarterly |
| Aluminum, Total Recoverable | Report | mg/L | Grab | Quarterly |
| Arsenic, Total Recoverable | Report | mg/L | Grab | Quarterly |
| Boron, Total Recoverable | Report | mg/L | Grab | Quarterly |
| Cadmium, Total Recoverable | 0.005 | mg/L | Grab | Quarterly |
| Chloride (as Cl) | Report | mg/L | Grab | Quarterly |
| Chromium, Total Recoverable | 0.100 | mg/L | Grab | Quarterly |
| Cobalt, Total Recoverable | Report | mg/L | Grab | Quarterly |
| Iron, Total Recoverable | Report | mg/L | Grab | Quarterly |
| Lead, Total Recoverable | 0.015 | mg/L | Grab | Quarterly |
| Magnesium, Total Recoverable | Report | mg/L | Grab | Quarterly |
| Mercury, Total Recoverable | 0.002 | mg/L | Grab | Quarterly |
| Selenium, Total Recoverable | 0.050 | mg/L | Grab | Quarterly |
| Sulfate, Total | Report | mg/L | Grab | Quarterly |
| Solids, Total Dissolved (TDS) | Report | mg/L | Grab | Quarterly |
| Alpha, Gross Particle Activity | 15 | pCi/L | Grab | Quarterly |
| Radium 226 + Radium 228, Total | 5 | pCi/L | Grab | Quarterly |

For piezometers, monitoring and reporting is required only for water level information.

*[62-520.600(11)(b)]*

4. The following parameters shall be analyzed for each monitoring well identified in Permit Condition III.2 excluding those monitored for in Permit Condition III.3. Results shall be reported in accordance with Permit Condition III.18:

| Parameter | Compliance Well Limit | Units | Sample Type | Monitoring Frequency |
|---|---|---|---|---|
| Water Level Relative to NGVD | Report | ft | In Situ | Annually |
| pH | Report | s.u. | Grab | Annually |
| Specific Conductance | Report | umhos/cm | Grab | Annually |
| Aluminum, Total Recoverable | Report | mg/L | Grab | Annually |
| Arsenic, Total Recoverable | Report | mg/L | Grab | Annually |
| Cadmium, Total Recoverable | 0.005 | mg/L | Grab | Annually |
| Chloride (as Cl) | Report | mg/L | Grab | Annually |
| Chromium, Total Recoverable | 0.100 | mg/L | Grab | Annually |
| Iron, Total Recoverable | Report | mg/L | Grab | Annually |
| Lead, Total Recoverable | 0.015 | mg/L | Grab | Annually |
| Magnesium, Total Recoverable | Report | mg/L | Grab | Annually |
| Mercury, Total Recoverable | 0.002 | mg/L | Grab | Annually |
| Selenium, Total Recoverable | 0.050 | mg/L | Grab | Annually |
| Sulfate, Total | Report | mg/L | Grab | Annually |
| Solids, Total Dissolved (TDS) | Report | mg/L | Grab | Annually |
| Alpha, Gross Particle Activity | 15 | pCi/L | Grab | Once Every 5 Years |

| Parameter | Compliance Well Limit | Units | Sample Type | Monitoring Frequency |
|---|---|---|---|---|
| Radium 226 + Radium 228, Total | 5 | pCi/L | Grab | Once Every 5 Years |

For piezometers, monitoring and reporting is required only for water level information.

*[62-520.600(11)(b)]*

5. The zone of discharge for the ash pond shall extend horizontally along the ground surface to the facility's property line and vertically from the land surface to the base of the surficial aquifer. *[62-520.200(27)] [62-520.465]*

6. A complete sampling record shall be provided for each monitoring well. This record shall include water level, total depth of the well, volume of water in the well, volume of water removed, stabilization documentation including pH, conductivity, and temperature; time interval of purging; time sample is taken; and device(s) used for purging (including discharge rate) and sampling.

7. When Gross Alpha Particle Activity is detected above 5.0 pCi/L, then combined Radium 226 and 228 shall be tested and reported.

8. In the event the water quality monitoring shows a violation of the applicable water quality standards, the permittee shall arrange for a confirmation re-sampling within 15 days after the permittee's receipt of laboratory results. In the event that the permittee chooses not to conduct the reconfirmation sampling, the Department shall consider the initial analysis to be representative of the current water quality conditions at this facility. If the initial results demonstrate or the re-sampling confirms ground water contamination, the permittee shall notify the Department in writing within 14 days of this finding.

9. The permittee shall develop a written technical report pursuant to the schedule in Condition VI.3 to summarize and interpret the water quality data and water levels obtained from permit issuance to the date of renewal application submittal. The report shall be submitted by a qualified professional and shall contain the following items at a minimum:

   a. Tabular displays of any data which shows that a monitoring parameter has been detected, and graphical displays of any leachate key indicator parameters detected (such as pH, specific conductance, TDS, TOC, sulfate, chloride, sodium and iron), including hydrographs for all monitor wells;

   b. Trend analysis of any monitoring parameters consistently detected;

   c. Comparisons among shallow, middle, and deep zone wells, as applicable;

   d. Comparisons between background water quality and the water quality in detection and compliance wells;

   e. Correlations between related parameters such as total dissolved solids and specific conductance, as applicable;

   f. Discussion of erratic and/or poorly correlated data;

   g. An interpretation of the ground water contour maps, including an evaluation of ground water flow rates; and

   h. An interpretation of the ground water contour maps, including an evaluation of ground water flow rates.

   *[62-701.510(8)(b)]*

10. 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.

11. The ground water minimum criteria specified in Rule 62-520.400 F.A.C., shall be met within the zone of discharge. *[62-520.400 and 62-520.420(4)]*

12. If the concentration for any constituent listed in Conditions III.3 or III.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 background quality shall be the prevailing standard. *[62-520.420(2)]*



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13. Water levels in each monitoring well shall be measured in a single day. During well sampling, water levels shall be measured on the sample day and recorded prior to evacuating the wells or collecting samples. Water level, top of well casing and land surface elevations at each well site, at a precision of plus or minus 0.01 feet using a consistent, nationally recognized datum, shall be reported on each analysis report. Prior to sampling, the field parameters shall be stabilized from each well. Sampling and purging methods in the SOPs, as allowed in Chapter 62-160, F.A.C. must be used. *[62-520.600(11)(c)]*

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

15. If any monitoring well becomes damaged or inoperable, the permittee shall notify the Department's Northwest District Office immediately and a detailed written report shall follow within seven days. The written report shall detail what problem has occurred and remedial measures that have been taken to prevent recurrence. All monitoring well design and replacement shall be approved by the Department's Northwest District Office prior to installation. *[62-520.600(6)(l)]*

16. 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(5), F.A.C., unless future use is intended. *[62-532.500(5)]*

17. 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.

18. The results pertaining to groundwater monitoring requirements under Part III of this permit shall be submitted electronically on compact disc media readable by a Microsoft Windows computer to:

    Florida Department of Environmental Protection
    Northwest District Office
    Solid Waste Section
    160 W. Government Street, Suite 308
    Pensacola, Florida 32502

    And to:

    Florida Department of Environmental Protection
    Bob Martinez Center
    Solid Waste Section
    2600 Blair Stone Road
    MS 4565
    Tallahassee, Florida, 32399-2400

    The data shall be evaluated using ADaPT to conduct data quality review and compliance checking. The owner or operator shall include DEP Form 62-701.900(31), Water Quality Monitoring Certification provided as Attachment 1 with each report certifying that the laboratory results have been reviewed and approved by the owner or operator. To download the appropriate version of the ADaPT software for data entry and submittals and for other general information related to the use of ADaPT, go to the DEP's web site at:

    http://www.dep.state.fl.us/waste/categories/shw/pages/ADaPT.htm

    The ADaPT water quality analysis shall be submitted electronically on compact disc media readable by a Microsoft Windows computer. Electronic laboratory data must be submitted in a specific format called an Electronic Data Deliverable (EDD). The submittal shall also include Chain of Custody sheets, field data sheets (Form FD 9000-24 provided as Attachment 2), groundwater contour maps, water elevation table, summary of exceedances, recommendations, and the Groundwater Monitoring Report Certification. The Department will use ADaPT to conduct data quality review and compliance checking.



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*[62-160.240(3) and 62-160.340(4)]*

## IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

Section IV is not applicable to this facility.

## V. 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 on-site domestic facility shall have a Class D or higher operator 2 visits/week on nonconsecutive days for a total of 1 hour/week. There shall be no more than 5 days between the last visit in one week and the first visit in the next week. The lead/chief operator for the domestic facility must be a Class D operator, or higher.

3. When the three-month average daily flow for the most recent three consecutive months exceeds 50 percent of the permitted capacity of the domestic wastewater treatment plant or reuse and disposal systems, the permittee shall submit to the Department's Northwest District Office a capacity analysis report. This initial capacity analysis report shall be submitted within 180 days after the last day of the last month of the three-month period referenced above. The capacity analysis report shall be prepared in accordance with Rule 62-600.405, F.A.C. *[62-600.405(4)]*

4. The permittee shall maintain the following records and make them available for inspection on the site of the permitted facility.

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

   b. Copies of all reports required by the permit for at least three years from the date the report was prepared;

   c. Records of all data, including reports and documents, used to complete the application for the permit for at least three years from the date the application was filed;

   d. A copy of the current permit;

   e. A copy of any required record drawings; and

   f. 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]*

5. During the period of operation authorized by this permit, the wastewater facility shall, as part of the regular maintenance schedule, review the structural integrity of all outfalls, including all outfalls which have been taken out of service.

## VI. SCHEDULES

1. The following improvement actions shall be completed according to the following schedule. The Best Management Practices/Pollution Prevention (BMP3) Plan shall be prepared and implemented in accordance with Part VII of this permit.

| Action Item | Completion Date |
|---|---|
| 1. Continue implementing the existing BMP3 Plan | Issuance date of permit |

*[62-620.320(6)]*



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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. No later than 120 days after the final groundwater sampling event, the permittee shall submit a technical report on groundwater in accordance with the requirements of Condition III.9 to the Northwest District Office.

4. The application to renew this permit shall include a detailed operation and maintenance performance report prepared in accordance with Rule 62-600.735, F.A.C. *[62-600.735(1)]*

## VII. BEST MANAGEMENT PRACTICES/STORMWATER POLLUTION PREVENTION PLANS

1. General Conditions

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 plan for utilizing practices incorporating pollution prevention measures. References to be considered in developing the plan are "Criteria and Standards for Best Management Practices Authorized Under Section 304(e) of the Act," found at 40 CFR 122.44 Subpart K and the Storm Water Management Industrial Activities Guidance Manual, EPA/833-R92-002 and other EPA documents relating to Best Management Practice guidance.

a. Definitions
   (1) The term "pollutants" refers to conventional, non-conventional and toxic pollutants.
   (2) Conventional pollutants are: biochemical oxygen demand (BOD), suspended solids, pH, fecal coliform bacteria and oil & grease.
   (3) Non-conventional pollutants are those which are not defined as conventional or toxic.
   (4) Toxic pollutants include, but are not limited to: (a) any toxic substance listed in Section 307(a)(1) of the CWA, any hazardous substance listed in Section 311 of the CWA, or chemical listed in Section 313(c) of the Superfund Amendments and Reauthorization Act of 1986; and (b) any substance (that is not also a conventional or non-conventional pollutant except ammonia) for which EPA has published an acute or chronic toxicity criterion.
   (5) "Significant Materials" is defined as raw materials; fuels; materials such as solvents and detergents; hazardous substances designated under Section 101(14) of CERCLA; and any chemical the facility is required to report pursuant to EPCRA, Section 313; fertilizers; pesticides; and waste products such as ashes, slag and sludge.
   (6) "Pollution prevention" and "waste minimization" refer to the first two categories of EPA's preferred hazardous waste management strategy: first, source reduction and then, recycling.
   (7) "Recycle/Reuse" is defined as the minimization of waste generation by recovering and reprocessing usable products that might otherwise become waste; or the reuse or reprocessing of usable waste products in place of the original stock, or for other purposes such as material recovery, material regeneration or energy production.
   (8) "Source reduction" means any practice which: (a) reduces the amount of any pollutant entering a waste stream or otherwise released into the environment (including fugitive emissions) prior to recycling, treatment or disposal; and (b) reduces the hazards to public health and the environment associated with the release of such pollutant. The term includes equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control. It does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a pollutant through a process or activity which itself is not integral to, or previously considered necessary for, the production of a product or the providing of a service.
   (9) "BMP3" means a Best Management Practices Pollution Prevention Plan incorporating the requirements of 40 CFR § 125, Subpart K, plus pollution prevention techniques, except where other existing programs are deemed equivalent by the permittee. The permittee shall certify the equivalency of the other referenced programs.



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(10) The term "material" refers to chemicals or chemical products used in any plant operation (i.e., caustic soda, hydrazine, degreasing agents, paint solvents, etc.). It does not include lumber, boxes, packing materials, etc.

2. Best Management Practices/Pollution Prevention Plan

The permittee shall develop and implement a BMP3 plan for the facility, which is the source of wastewater and storm water discharges, covered by this permit. The plan shall be directed toward reducing those pollutants of concern, including mercury, which discharge to surface waters and shall be prepared in accordance with good engineering and good housekeeping practices. For the purposes of this permit, pollutants of concern shall be limited to toxic pollutants, as defined above, known to the discharger. The plan shall address all activities which could or do contribute these pollutants to the surface water discharge, including process, treatment, and ancillary activities.

a. Signatory Authority & Management Responsibilities

The BMP3 plan shall be signed by permittee or their duly authorized representative in accordance with rule 62-620.305(2)(a) and (b). The BMP3 plan shall be reviewed by plant environmental/engineering staff and plant manager. Where required by Chapter 471-(P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of the BMP3 plant shall be signed and sealed by the professional(s) who prepared them.

A copy of the plant shall be retained at the facility and shall be made available to the permit issuing authority upon request.

The BMP3 plan shall contain a written statement from corporate or plant management indicating management's commitment to the goals of the BMP3 program. Such statements shall be publicized or made known to all facility employees. Management shall also provide training for the individuals responsible for implementing the BMP3 plan.

b. BMP3 Plan Requirements
(1) Name & description of facility, a map illustrating the location of the facility & adjacent receiving waters, and other maps, plot plans or drawings, as necessary;
(2) Overall objectives (both short-term and long-term) and scope of the plan, specific reduction goals for pollutants, anticipated dates of achievement of reduction, and a description of means for achieving each reduction goal;
(3) A description of procedures relative to spill prevention, control & countermeasures and a description of measures employed to prevent storm water contamination;
(4) A description of practices involving preventive maintenance, housekeeping, recordkeeping, inspections, and plant security; and
(5) The description of a waste minimization assessment performed in accordance with the conditions outlined in condition c below, results of the assessment, and a schedule for implementation of specific waste reduction practices.

c. Waste Minimization Assessment

The permittee is encouraged but not required to conduct A waste minimization assessment (WMA) for this facility to determine actions that could be taken to reduce waste loading and chemical losses to all wastewater and/or storm water streams as described in Part VII.2 of this permit.

If the permittee elects to develop and implement a WMA, information on plan components can be obtained forms the Department's Industrial Wastewater website, or from:

Florida Department of Environmental Protection
Industrial Wastewater Program, Mail Station 3545
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8589
(850) 245-8669 – Fax

d. Best Management Practices & Pollution Prevention Committee Recommended:

A Best Management Practices Committee (Committee) should be established to direct or assist in the implementation of the BMP3 plan. The Committee should be comprised of individuals within the plant organization who are responsible for developing the BMP3 plan and assisting the plant manager in its

implementation, monitoring of success, and revision. The activities and responsibilities of the Committee should address all aspects of the facility's BMP3 plan. The scope of responsibilities of the Committee should be described in the plan.

e. Employee Training

Employee training programs shall inform personnel at all levels of responsibility of the components & goals of the BMP3 plan and shall describe employee responsibilities for implementing the plan. Training shall address topics such as good housekeeping, materials management, record keeping & reporting, spill prevention & response, as well as specific waste reduction practices to be employed. Training should also disclose how individual employees may contribute suggestions concerning the BMP3 plan or suggestions regarding Pollution Prevention. The plan shall identify periodic dates for such training.

f. Plan Development & Implementation

The BMP3 plan shall be developed and implemented 6 months after the effective date of this permit, unless any later dates are specified in this permit. Any portion of the WMA which is ongoing at the time of development or implementation shall be described in the plan. Any waste reduction practice which is recommended for implementation over a period of time shall be identified in the plan, including a schedule for its implementation.

g. Submission of Plan Summary & Progress/Update Reports

(1) Plan Summary: Not later than 2 years after the effective date of the permit, a summary of the BMP3 plan shall be developed and maintained at the facility and made available to the permit issuing authority upon request. The summary should include the following: a brief description of the plan, its implementation process, schedules for implementing identified waste reduction practices, and a list of all waste reduction practices being employed at the facility. The results of waste minimization assessment studies already completed as well as any scheduled or ongoing WMA studies shall be discussed.

(2) Progress/Update Reports: Annually thereafter for the duration of the permit progress/update reports documenting implementation of the plan shall be maintained at the facility and made available to the permit issuing authority upon request. The reports shall discuss whether or not implementation schedules were met and revise any schedules, as necessary. The plan shall also be updated as necessary and the attainment or progress made toward specific pollutant reduction targets documented. Results of any ongoing WMA studies as well as any additional schedules for implementation of waste reduction practices shall be included.

(3) A timetable for the various plan requirements follows:

Timetable for BMP3 Plan Requirements:

| REQUIREMENT | TIME FROM EFFECTIVE DATE OF THIS PERMIT |
|---|---|
| Progress/Update Reports | 3 years, and then annually thereafter |

The permittee shall maintain the plan and subsequent reports at the facility and shall make the plan available to the Department upon request.

h. Plan Review & Modification

If following review by the Department, the BMP3 plan is determined insufficient, the permittee will be notified that the BMP3 plan does not meet one or more of the minimum requirements of this Part. Upon such notification from the Department, the permittee shall amend the plan and shall submit to the Department a written certification that the requested changes have been made. Unless otherwise provided by the Department, the permittee shall have 30 days after such notification to make the changes necessary.

The permittee shall modify the BMP3 plan whenever there is a change in design, construction, operation, or maintenance, which has a significant effect on the potential for the discharge of pollutants to waters of the State or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or storm water discharges. Modifications to the plan may be reviewed by the Department in the same manner as described above.



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## 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 Northwest 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 Northwest 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 Northwest 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. Impoundment Design, Construction, Operation, and Maintenance

1. All ash 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. Operation and maintenance of any ash impoundment shall be in accordance with all applicable State regulations. When practicable, piezometers or other instrumentation shall be used as a means to aid monitoring of impoundment integrity.

### D. Impoundment Integrity Inspections

1. No later than January 31, 2016, and annually thereafter, all impoundments shall be inspected by qualified personnel with knowledge and training in impoundment integrity. Annual inspections shall 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 such as overly lush, dead

or unnaturally tilted vegetation, and any other changes which may indicate a potential compromise to impoundment integrity, including subsidence and animal burrows.

2. Within 30 days after the annual inspection, a qualified, responsible officer shall certify to the Department that no breaches or structural defects resulting in the discharges to surface waters of the State and that no changes were observed which may indicate a potential compromise to impoundment integrity during the previous calendar year.

   The certification shall also include a statement that the ash pond provides the necessary minimum wet weather detention volume to contain the combined volume for all direct rainfall and all rainfall runoff to the pond resulting from the 10-year, 24-hour rainfall event and maximum dry weather plant waste flows which could occur during a 24-hour period. The certification shall be submitted to the Department's Northwest District Office.

3. The permittee shall conduct follow-up inspections within 7 days after large or extended rain events (i.e., 25-year, 24-hour precipitation event).

4. In the event that a critical condition in the ash impoundment, such as the conditions listed below, is suspected that may result in a potential discharge to surface waters of the State, the permittee shall notify the Department within twenty-four (24) hours of becoming aware of the situation and provide a proposed course of corrective action and implementation schedule within fifteen (15) days from the time existence of the critical condition is confirmed and the Department was notified.

**E. Reporting and Recordkeeping Requirements for Impoundments**

1. The summarized findings of all monitoring activities, inspections, and corrective actions pertaining to the impoundment integrity, and operation and maintenance of all impoundments shall be documented and kept on-site in accordance with permit condition V.3, and made available to Department inspectors upon request.

2. Starting with the issuance of this permit, all pertinent impoundment permits, design, construction, operation, and maintenance information, including but not limited to: plans, geotechnical and structural integrity studies, copies of permits, associated certifications by qualified, Florida-registered professional engineer, and regulatory approvals, shall be kept on site in accordance with permit condition V.3 and made available to Department inspectors upon request.

**F. 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 (**MMDDYY**) 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.

**G. 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)]*



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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)]*



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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 being taken to prevent future occurrence of the noncompliance.

    *[62-620.610(17)]*

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246 and Chapters 62-160, 62-601, and 62-610, F.A.C., and 40 CFR 136, as appropriate.

    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a 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 Northwest 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.



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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 Northwest 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 Northwest 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.



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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. a. 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)]*

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



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**FACT SHEET**
**FOR**
**STATE OF FLORIDA INDUSTRIAL WASTEWATER FACILITY PERMIT**

PERMIT NUMBER: FL0002283-005 (Major)

FACILITY NAME: Scholz Electric Generating Plant

FACILITY LOCATION: 1460 Gulf Power Road, Sneads, FL 32460
Jackson County

NAME OF PERMITTEE: Gulf Power Company

PERMIT WRITER: Frank Wall

1. SUMMARY OF APPLICATION

a. Chronology of Application

| | |
|---|---|
| Application Number: | FL0002283-005-IW1S |
| Application Submittal Date: | March 20, 2015 |
| Additional Information Submitted: | May 11th, 28th, 29th, June 24th, 2015 |

b. Type of Facility

This facility consists of two coal fired steam electric generating units (Units 1 and 2) with a total nameplate rating of 80 megawatts (MW), and a gross generation capacity of 98 MW.

SIC Code: 4911 - Fossil Fuel Electric Power Generation

c. Facility Capacity

| | |
|---|---|
| Existing Permitted Capacity: | 129.6 MGD Daily Maximum Flow |
| Proposed Increase in Permitted Capacity: | 0 MGD Daily Maximum Flow |
| Proposed Total Permitted Capacity: | 129.6 MGD Daily Maximum Flow |

d. Description of Wastewater Treatment

Non-contact once-through condenser cooling water (OTCW) discharges with chlorination to the on-site discharge canal, and thence to the Apalachicola River, a Class III fresh water. All other industrial and domestic wastewater streams discharge into the on-site ash pond. Discharges to the on-site ash pond consist of low volume wastes (LVW) (i.e. ash sluice water, water softener regeneration wastewater, boiler blowdown and air preheater wash), auxiliary equipment cooling water, coal pile runoff, yard sump runoff, and treated domestic wastewater. Domestic Wastewater receives secondary treatment in a package treatment plant prior to discharging to the ash pond. The ash pond overflow discharges intermittently to the on-site discharge canal, and thence to the Apalachicola River. The coal ash pond is scheduled to be closed during this permit cycle.

e. Description of Effluent Disposal and Land Application Sites (as reported by applicant)

Monitoring Group D-001:

Class III Fresh Waters, Apalachicola River

Pollutants which are present in significant quantities or which are subject to permit limitations are as follows:



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| Parameter | Units | Max/Min | Reported Value | Statistical Basis |
|---|---|---|---|---|
| Flow | MGD | Max | 43.9 | Annual Average |
| Temperature (F), Water (winter) | Deg F | Max | 60.19 * | Annual Average |
| Temperature (F), Water (summer) | Deg F | Max | 78.16 * | Annual Average |
| pH | s.u. | Min | 6.98 | Daily Minimum |
| | | Max | 8.10 | Daily Maximum |
| Oil and Grease | mg/L | Max | < 2.44 | Daily Maximum |
| Chlorine, Total Residual | mg/L | Max | < 0.02 | Daily Maximum |
| Copper, Total Recoverable | mg/L | Max | < 0.002 | Daily Maximum |
| Cadmium, Total Recoverable | mg/L | Max | < 0.000118 | Daily Maximum |
| Lead, Total Recoverable | mg/L | Max | < 0.002 | Daily Maximum |
| Iron, Total Recoverable | mg/L | Max | 0.317 | Daily Maximum |
| Mercury, Total Recoverable | ug/L | Max | 0.000791 | Daily Maximum |
| Nitrogen, Total | mg/L | Max | 0.754 | Daily Maximum |
| Phosphorus, Total | mg/L | Max | 0.03 | Daily Maximum |

*Value reported as Deg. F in Form 2CS rather than in Deg. C.

2. SUMMARY OF SURFACE WATER DISCHARGE

This facility does not have a new or expanded discharge to surface waters.

Monitoring Group D-001: Existing discharge of once-through cooling water from Units 1 and 2, along with intermittent overflow from the ash pond.

Monitoring Group I-012: Existing ash pond discharge to the discharge canal, consisting of ash sluice water, low volume wastes, auxiliary equipment cooling water, coal pile runoff, yard sump runoff, and treated domestic wastewater.

Monitoring Group I-013: Existing treated domestic wastewater plant effluent discharge to the ash pond.

The Department does not anticipate adverse impacts on threatened or endangered species as a result of permit issuance.

3. BASIS FOR PERMIT LIMITATIONS AND MONITORING REQUIREMENTS

This facility is authorized to discharge once-through non-contact cooling water and intermittent ash pond overflow from **Outfall D-001, COMBINED PLANT DISCHARGE,** to the Apalachicola River based on the following:

| Parameter | Units | TBEL | | WQBEL | | Permit Limit | | Rationale |
|---|---|---|---|---|---|---|---|---|
| | | Daily Max | Monthly Average | Daily Max | Monthly Average | Daily Max | Monthly Average | |
| Flow (Intake) | MGD | N/A | N/A | N/A | N/A | Report | N/A | 308(a) CWA, BPJ |
| Flow (combined discharge) | MGD | N/A | N/A | N/A | N/A | Report | N/A | 308(a) CWA, BPJ |
| Temperature (F), Water (Intake) | Deg F | N/A | N/A | N/A | N/A | Report | Report | 308(a) CWA, BPJ |
| Temperature (F), Water (Discharge) | Deg F | N/A | N/A | N/A | N/A | Report | Report | 62-302.520(1), F.A.C. |
| pH | s.u. | N/A | N/A | 8.5 (Max) | 6.0 (Min) | 8.5 (Max) | 6.0 (Min) | 62-302.530, F.A.C. |
| Oil and Grease | mg/L | N/A | N/A | 5.0 | N/A | 5.0 | 5.0 | 62-302.530, F.A.C., BPJ |
| Chlorine, Total Residual | mg/L | N/A | N/A | 0.01 | N/A | 0.01 | 0.01 | 62-302.530, F.A.C., BPJ |
| Chlorination Duration | min | 120 | N/A | N/A | N/A | 120 | N/A | 40 CFR Part 423.12(b)(8) |
| Aluminum, Total Recoverable | mg/L | N/A | N/A | N/A | N/A | Report | N/A | 62-302.530, F.A.C. |
| Arsenic, Total | ug/L | N/A | N/A | 50 | N/A | 50 | 50 | 62-302.530, F.A.C. |
| Beryllium, Total Recoverable | ug/L | N/A | N/A | 0.13 (An.Avg) | N/A | Report | N/A | 62-302.530, F.A.C. |
| Cadmium, Total Recoverable | ug/L | N/A | N/A | See below | N/A | See below | N/A | 62-302.530, F.A.C. |
| Chromium, Total Recoverable | ug/L | N/A | N/A | 11 | N/A | Report | N/A | 62-302.530, F.A.C. |
| Copper, Total Recoverable | ug/L | N/A | N/A | See below | N/A | See below | N/A | 62-302.530, F.A.C. |

| Parameter | Units | TBEL | | WQBEL | | Permit Limit | | Rationale |
|---|---|---|---|---|---|---|---|---|
| | | Daily Max | Monthly Average | Daily Max | Monthly Average | Daily Max | Monthly Average | |
| Iron, Total Recoverable | mg/L | N/A | N/A | 1.0 | N/A | 1.0 | 1.0 | 62-302.530, F.A.C., BPJ |
| Lead, Total Recoverable | ug/L | N/A | N/A | See below | N/A | See below | N/A | 62-302.530, F.A.C. |
| Mercury, Total Recoverable | ug/L | N/A | N/A | 0.012 | N/A | Report | N/A | 62-302.530, F.A.C., BPJ |
| Nickel, Total Recoverable | ug/L | N/A | N/A | See below | N/A | See below | N/A | 62-302.530, F.A.C. |
| Selenium, Total Recoverable | ug/L | N/A | N/A | 5.0 | N/A | Report | N/A | 62-302.530, F.A.C. |
| Vanadium, Total Recoverable | mg/L | N/A | N/A | N/A | N/A | Report | N/A | BPJ |
| Zinc, Total Recoverable | ug/L | N/A | N/A | See below | N/A | See below | N/A | 62-302.530, F.A.C. |
| Hardness, Total (as CaCO3) | mg/L | N/A | N/A | Report | Report | Report | N/A | 62-302.530, F.A.C. |
| Nitrogen, Ammonia, Total (as N) | mg/L | N/A | N/A | N/A | N/A | Report | N/A | 62-302, 62-302.530, 62-302.531, 62-302.532, F.A.C. |
| Nitrogen, Kjeldahl, Total (as N) | mg/L | N/A | N/A | N/A | N/A | Report | N/A | 62-302, 62-302.530, 62-302.531, 62-302.532, F.A.C. |
| Nitrogen, Nitrate, Total (as N) | mg/L | N/A | N/A | N/A | N/A | Report | N/A | 62-302, 62-302.530, 62-302.531, 62-302.532, F.A.C. |
| Nitrogen, Nitrite, Total (as N) | mg/L | N/A | N/A | N/A | N/A | Report | N/A | 62-302, 62-302.530, 62-302.531, 62-302.532, F.A.C. |
| Nitrogen, Total | mg/L | N/A | N/A | N/A | N/A | Report | N/A | 62-302, 62-302.530, 62-302.531, 62-302.532, F.A.C. |
| Nitrogen, Total | lb/year | N/A | N/A | N/A | N/A | Report (An.Total) | N/A | 62-302, 62-302.530, 62-302.531, 62-302.532, F.A.C. |
| Nitrogen, Total (Net) | lb/year | N/A | N/A | N/A | N/A | Report (An.Total) | N/A | 62-302, 62-302.530, 62-302.531, 62-302.532, F.A.C. |
| Phosphate, Ortho (as PO4) | mg/L | N/A | N/A | N/A | N/A | Report | N/A | 62-302, 62-302.530, 62-302.531, 62-302.532, F.A.C. |
| Phosphorus, Total (as P) | mg/L | N/A | N/A | N/A | N/A | Report | Report | 62-302, 62-302.530, 62-302.531, 62-302.532, F.A.C. |
| Phosphorus, Total (as P) | lb/year | N/A | N/A | N/A | N/A | Report (An.Total) | N/A | 62-302, 62-302.530, 62-302.531, 62-302.532, F.A.C. |
| Phosphorus, Total (as P) (Net) | lb/year | N/A | N/A | N/A | N/A | Report (An.Total) | N/A | 62-302, 62-302.530, 62-302.531, 62-302.532, F.A.C. |
| Chronic Whole Effluent Toxicity, 7-Day IC25 (Ceriodaphnia dubia) | percent | N/A | N/A | 100 (Min) | | 100 (Min) | | 62-302.530, 62-4.241(1)(b), 62-620.620(3), F.A.C. |
| Chronic Whole Effluent Toxicity, 7-Day IC25 (Pimephales promelas) | percent | N/A | N/A | 100 (Min) | | 100 (Min) | | 62-302.530, 62-4.241(1)(b), 62-620.620(3), F.A.C. |

The limit(s) for "Copper, Total Recoverable; Cadmium, Total Recoverable; Lead, Total Recoverable; Nickel, Total Recoverable; and Zinc, Total Recoverable" shall be calculated using the following equation(s):

$Cu \leq e^{(0.8545[\ln H]-1.702)}$ ug/L
$Cd \leq e^{(0.7409[\ln H]-4.719)}$ ug/L
$Pb \leq e^{(1.273[\ln H]-4.705)}$ ug/L
$Ni \leq e^{(0.846[\ln H]+0.0584)}$ ug/L
$Zn \leq e^{(0.8473[\ln H]+0.884)}$ ug/L

Total hardness shall be measured at the time of the effluent sample. The "ln H" means the natural logarithm of total hardness expressed as mg/L of $CaCO_3$. For metals criteria involving equations with hardness, the hardness shall be set at 25 mg/L if actual hardness is <25 mg/L and set at 400 mg/L if actual hardness is >400 mg/L. *[62-302.530(23), 62-302.530(15), 62-302.530(39)]*

This facility is authorized to discharge low volume wastes, auxiliary equipment cooling water, coal pile runoff, yard sump runoff, and treated domestic wastewater from **Internal Outfall I-012, ASH POND DISCHARGE**, to the discharge canal based on the following:

| Parameter | Units | TBEL | | WQBEL | | Permit Limit | | Rationale |
|---|---|---|---|---|---|---|---|---|
| | | Daily Max | Monthly Average | Daily Max | Monthly Average | Daily Max | Monthly Average | |
| Flow | MGD | N/A | N/A | N/A | N/A | Report (Day.Av) | - | 308(a) CWA, BPJ |
| Solids, Total Suspended | mg/L | 100.0 | 30.0 | N/A | N/A | 100.0 | 30.0 | 40 CFR Part 423.12(b)(3) and (4) |
| Oil and Grease | mg/L | 20.0 | 15.0 | N/A | N/A | 20.0 | 15.0 | 40 CFR Part 423.12(b)(3) and (4) |
| pH | s.u. | 9.0 (Max) | 6.0 (Min) | N/A | N/A | 9.0 (Max) | 6.0 (Min) | 40 CFR Part 423.12(b)(1) |
| Nickel, Total Recoverable | ug/L | N/A | N/A | N/A | N/A | Report (In.Max) | - | BPJ, See 5.f |

This facility is authorized to discharge treated domestic treatment plant wastewater from **Internal Outfall I-013, DOMESTIC WASTEWATER TREATMENT PLANT EFFLUENT**, to the ash pond based on the following:

| Parameter | Units | TBEL | | WQBEL | | Permit Limit | | Rationale |
|---|---|---|---|---|---|---|---|---|
| | | Daily Max | Monthly Average | Daily Max | Monthly Average | Daily Max | Monthly Average | |
| Flow | MGD | N/A | N/A | N/A | N/A | Report | Report | 308(a) CWA, BPJ |
| Biochemical Oxygen Demand-5 | mg/L | 60.0 | 25.0 | N/A | N/A | 60.0 | 25.0 | 62-620.100(3)(g) F.A.C. and 40 CFR 133.102(a)(4)(i), 62-600.740(1)(b)1.d. F.A.C. |
| Solids, Total Suspended | mg/L | 60.0 | 30.0 | N/A | N/A | 60.0 | 30.0 | 62-600.740(1)(b)1.b. and 62-600.740(1)(b)1.d., F.A.C. |
| Coliform, Fecal | #/100 mL | N/A | N/A | See Permit condition (I.B.6) | | The arithmetic mean of the monthly fecal coliform values collected during an annual period, shall not exceed 200 per 10ml of reclaimed water. See Permit condition (I.B.6) | | 62-600.440(4)(c) |

Reasonable Assurance

The facility has provided reasonable assurance that the discharge will not adversely affect the designated used of receiving water. Inspection data, as well as all other available data, have been evaluated in accordance with the Department's reasonable assurance procedures to ensure that no limits other than those included in this permit are needed to maintain Florida's water quality standards. The Department conducted sampling February 18, 2015 for the Fifth Year Inspection concluding that "the effluent does not appear to be negatively impacting the receiving waters", and that "all other parameters and analytes were similar between the effluent samples and the Test and Control Site samples".

WQBEL Consideration

A Level I WQBEL was performed for the discharge, and is embodied in this Fact Sheet based on historical discharge monitoring data, available inspection reports, and the effluent characterization provided with the application.

4. BASIS FOR SPECIFIC PERMIT CONDITIONS

a. The polychlorinated biphenyl compound prohibition was included in permit condition I.C.8 as required by 40 CFR 423.12(b)(2).

b. 316(b) Demonstration

Section 316(b) of the Clean Water Act (CWA) requires that the location, design, construction, and capacity of cooling water intake structures (CWIS) reflect the best technology available (BTA) to protect aquatic organisms from physical, thermal, or chemical stresses from impingement (pinned against intake screens) or entrainment (drawn completely through cooling water systems from intake to discharge). The Department is continuing the longstanding practice of applying Section 316(b) of the CWA on a case-by-case basis to existing facilities using

best professional judgment (BPJ). In order to minimize impingement and entrainment impacts the permit requires that the through-screen velocity be maintained at current levels such that the existing maximum velocity is not exceeded.

On August 15, 2014, EPA published new rules for existing large steam electric power plants that use surface waters in their intake cooling water systems. The new rules became effective on October 14, 2014. The 316(b) rule describes the compliance schedule for submitting reports and supporting documents to the Department which is some-what flexible and based on the NPDES permitting cycle for each facility. Permittees with a current permit that expires before July 18, 2018, may request that the Department establish an alternate schedule for submitting the required information.

As of April 15, 2015 the facility ceased coal-fired operations and will use less than 5 percent of the intake water withdrawn from the Apalachicola River for cooling. Based on the operational changes, the facility is not subject to the 316(b) study requirements of 40 CFR 122.21(r). However, if the facility resumes the use of cooling water such that the requirements of 40 CFR 125.91 are applicable, the permittee shall complete all studies and gather all information required under 40 CFR 122.21(r) for submittal with the subsequent renewal application. The permit requires the facility to develop and implement a Plan of Study for closure of the ash pond during the permit cycle. In the interim, discharges are limited to those resulting from maintenance activities. The facility has one intake structure with a design intake flow of 129.6 MGD.

c. Thermal Considerations

The thermal component of the discharge is subject to compliance with Florida Water Quality Standards. Section 62-302.520(1)(a) of the Florida Administrative Code provides that heated water discharges existing on July 1, 1972, "shall not increase the temperature of the RBW (receiving body of water) so as to cause substantial damage or harm to the aquatic life or vegetation therein or interfere with beneficial uses assigned to the RBW".

Based upon 62-302.520, F.A.C., the permittee submitted the results of a plan of study with the previous permit renewal application to investigate whether the thermal discharge from the facility was creating an adverse impact upon the biological community of the surrounding habitat. The results were reviewed by the Department's Biology Section and upon completion of the review, the Department determined that, based upon the supplied data, the thermal discharge from the facility was not having an adverse impact upon the surrounding area. In addition, the Department conducted sampling February 18, 2015 for the Fifth Year Inspection in which the Department concluded that "the effluent does not appear to be negatively impacting the receiving waters".

As of April 15, 2015, the facility ceased coal-fired operations and stated that electric generation will not occur during the cycle. Therefore, the thermal component of the discharge from the use of once-through cooling water is not expected to impact the receiving waters. Negligible thermal impacts are anticipated from the use of cooling water for maintenance activities in which less than 5 percent of the water withdrawn from the intake structure will be used to cool equipment, such as air compressor coolers and service water bearing coolers.

d. Impaired Water Considerations

The facility is required to demonstrate protection for both the immediate receiving water and downstream waterbodies described above. Downstream protection with regard to nutrients is in accordance with 62-302.531(4), F.A.C. As of April 15, 2015 the facility ceased coal-fired operations and stated that electric generation will not occur during the next permit cycle. Based on the these operational changes, intermittent nature of the discharges, and ash pond closure during the forthcoming permit cycle, it is anticipated that discharge of nutrients and therefore, the impact on receiving waters from nutrient loading will be minimal. The Department conducted sampling February 18, 2015 for the Fifth Year Inspection concluding, with regard to chemical and biological sampling and analysis, that "the effluent does not appear to be negatively impacting the receiving waters". The biological assessment from the inspection also concluded that "The Test Site (downstream of D-001) Shannon-Weaver diversity score and number of individuals collected from Hester-Dendy samplers was higher than that of the Control Site (upstream of D-001)". Inspection sampling was conducted prior to the operational changes.

Receiving Waters

The facility discharges to the Apalachicola River, which is designated as WBID 375G, in the Apalachicola – Chipola Group 2 Basin. WBID 375G is not listed as impaired for nutrients or nutrient response variables (dissolved oxygen or chlorophyll a). This segment is located in nutrient region, Panhandle West, with annual geometric mean concentration threshold values of 0.06 and 0.67 mg/l, for total phosphorus (TP) and total nitrogen (TN), respectively, in accordance with Rule 62-302.531(2)(c)2, F.A.C., applicable to streams.

Downstream Receiving Water

Downstream stream WBIDs 375A-F (Apalachicola River):

WBID 375A is listed as impaired for bacteria in shellfish. WBID 375E listed for fecal and total coliforms on the Department's Statewide Comprehensive Delist List. Additionally, none of these downstream WBIDs are listed as impaired for nutrients or nutrient response variables (dissolved oxygen or chlorophyll a). These segment are located in nutrient region, Panhandle West, with annual geometric mean concentration threshold values of 0.06 and 0.67 mg/l, for total phosphorus (TP) and total nitrogen (TN), respectively, in accordance with Rule 62-302.531(2)(c)2, F.A.C., applicable to streams.

Downstream estuary WBID 1274 (Apalachicola Bay):

WBID 1274 is included on the Department's Verified List of Impaired Waters for bacteria in shellfish, and fecal coliform, and is on the Department's Statewide Comprehensive Delist List for nutrients. The Apalachicola Bay estuary threshold values for TP, TN, and Chlorophyll a are 0.063 mg/l, 0.84 mg/l, and 8.4 ug/l, respectively, Rule 62-302.532(1)(p)(1), F.A.C.

Downstream coastal WBIDs 8019 and 8020 (Apalachicola Offshore located in the Gulf of Mexico):

These WBIDs are also referred to as Apalachicola Bay Gulf 2 and 3, respectively, in the 2005 Water Quality Assessment Report for the Apalachicola – Chipola Group 2 Basin. The Apalachicola Offshore threshold values for TP, TN, and Chlorophyll a are 0.032 mg/l, 0.57 mg/l, and 8.2 ug/l, respectively, Rule 62-302.532(1)(p)(5), F.A.C.

Mercury:

All WBIDs described above are included on the Department's Verified List of Impaired Waters for mercury in fish tissue assessed using the Impaired Surface Waters Rule (IWR).

Based on the review of available mercury data sampled at outfall D-001 for the current permit cycle, the facility's discharge does not have a reasonable potential to cause or contribute to an exceedance of the Class III fresh water total recoverable mercury criterion in Rule 62-302.530, F.A.C

However, a requirement to prepare and implement a mercury minimization plan as required by Rule 62- 304.900, F.A.C., for the statewide mercury total maximum daily load, minimization of mercury through the Best Management Practices/Pollution Prevention (BMP3) Plan was added to Section VII of the permit. A Statewide Total Maximum Daily Load (TMDL) for mercury was adopted October 24, 2013.

f. Ash Pond Impoundment Conditions

The permittee has entered into a settlement agreement with Apalachicola River Keeper, Southern Alliance for Clean Energy and Waterkeeper Alliance (Plaintiffs). A copy of the settlement agreement was filed with the U.S. District Court on June 24, 2015. The Department is not a party to the settlement agreement.

The settlement agreement requires the permittee to close all coal ash ponds at the facility in accordance with the Essential Requirements for Ash Pond Closure Plan ("Closure Plan"). The terms of the Closure Plan are outlined in Section I of the Settlement Agreement and are detailed in Attachment 3 to the settlement agreement. Under the Closure Plan, the permittee must dewater the coal ash (coal combustion residuals or CCRs); construct a CCR upland dry storage area and a cutoff wall that diverts groundwater flow around the area beneath the dry storage area; transfer the CCR from the lower ash pond to the dry storage area; transfer any CCR from the middle ash pond

not already in the dry storage area; and apply for and obtain any necessary permits and approvals for closure of the coal ash ponds.

Permit condition II.B.4 requires the permittee to submit for the DEP's review and approval a plan for the closure of the coal ash ponds. The submittal must address ash dewatering, removal, and disposal; construction of ash disposal area; any re-direction of groundwater, stormwater or wastewater; removal or capping of existing outfalls; post closure groundwater monitoring; and provide reasonable assurance that discharges to surface waters will meet applicable water quality standards, and effluent guidelines in 40 CFR 423.

Permit condition III.D also continues the requirements for the permittee to conduct impoundment integrity inspections and certify annually to the Department.

5. DISCUSSION OF CHANGES TO PERMIT LIMITATIONS

The current wastewater permit for this facility FL0002283-005-IW1S expires on September 22, 2015.

The following changes were made to the permit from the previous cycle:

a. Condition I.A.1 was revised to include additional monitoring requirements for nutrients in terms of mass loadings. The combined nitrite/nitrate monitoring requirements were replaced with individual nitrite and nitrate parameters. Monitoring for the intake flow at INT-1 was also included to calculate the actual intake flow (AIF) for purposes of calculating the net load of nutrients from the facility.

b. Condition I.A.1 was updated to include monitoring requirements for aluminum, arsenic, beryllium, chromium, nickel, selenium, vanadium, and zinc. Condition I.A.4 was also revised to include the hardness-based equations for nickel and zinc effluent limitations.

c. Permit condition I.A.11 was updated for compliance with the final 316(b) regulations requirements. See Section 4.b above for additional information.

d. A new permit condition I.A.12 requires the facility to complete the studies pursuant to 40 CFR 122.21(r) if the facility resumes the use of once-through cooling water such that the requirements of 40 CFR 125.91 are applicable. See Section 4.b above for additional information.

e. A new permit condition I.A.13 regarding "take" was included for compliance with the Endangered Species Act and the final 316(b) regulations requirements. See Section 4.b above for additional information.

f. In permit condition I.B.3, the monthly average effluent limitation for biochemical oxygen demand was revised from 30 to 25 mg/L. The change is consistent with 62-620.100(3)(g), F.A.C. and 40 CFR 133.102(a)(4)(i).

g. Conditions in Section I.C. were updated to authorize the use of chemical product equivalents. Also, a new condition was included to clarify a list of other routine activities that do not require a revision to the permit pursuant to Rule 62-620.200(26)(a) & (b), F.A.C.

h. A condition was included in Section II of the permit requiring the facility to submit a closure plan for the ash impoundments/disposal areas. This requirement is consistent with the Settlement Agreement discussed in Section 4.f above. Condition III.3 was also included in order to be consistent with the Agreement

i. Permit conditions III.9, 13 and 18 were updated to be consistent with Rules 62-701.510(8)(b), 62-520.600(11)(c), and 62-160.240(3) and 62-160.340(4), F.A.C., respectively. Previous permit condition III.14 regarding monitoring well purging was removed to avoid redundancy. Requirements for well purging can be found in permit condition III.13.

j. Due to the modification of permit condition I.A.11, schedule item VI.3 regarding development of an aquatic organism return plan was removed.

k. New permit condition VI.3 was included in the Schedules section to provide a submittal date for a groundwater technical report required by Condition III.9.

6. DOMESTIC RESIDUALS MANAGEMENT

The method of residuals use or disposal by this facility is transport to a residuals management facility (RMF). Conditions were included in the permit to properly regulate the transfer of the residuals to a management facility, according to 62-640, F.A.C.

7. GROUND WATER MONITORING REQUIREMENTS

Ground water monitoring requirements have been established in accordance with Chapter 62-520, F.A.C. Developed permit condition III.3 in the draft renewal permit is consistent with the Settlement Agreement discussed in Section 4.f above.

8. PERMIT SCHEDULES

See Section VI. (Schedules) of the permit. Developed permit conditions VI.4 and VI.5 in the draft renewal permit are consistent with the Settlement Agreement discussed in Section 4.f above.

9. BEST MANAGEMENT PRACTICES/STORMWATER POLLUTION PREVENTION PLANS

As stated in Section VII of the permit, a Best Management Practices/Pollution Prevention (BMP3) Plan is required for the facility, pursuant to Rule 62-620.100(m), F.A.C., and 40 CFR Part 122.44(k). The plan provides a facility-specific approach for the minimizing of pollutant discharge from ancillary activities.

Due to the nature of the facility, a Best Management Practices/Pollution Prevention (BMP3) Plan is appropriate for the facility.

10. ADMINISTRATIVE ORDERS (AO) AND CONSENT ORDERS (CO)

This permit is not accompanied by an AO and has not entered into a CO with the Department.

11. REQUESTED VARIANCES OR ALTERNATIVES TO REQUIRED STANDARDS

No variances were requested for this facility.

12. THE ADMINISTRATIVE RECORD

The administrative record including application, draft permit, fact sheet, public notice (after release), comments received and additional information is available for public inspection during normal business hours at the location specified in item 13. Copies will be provided at a minimal charge per page.

13. PROPOSED SCHEDULE FOR PERMIT ISSUANCE

| | |
|---|---|
| Draft Permit and Public Notice to Applicant and EPA | August 24, 2015 |
| Public Comment Period | Beginning: August 31, 2015<br>Ending: September 29, 2015 |
| Proposed Permit to EPA | October 13, 2015 |
| Notice of Intent to Issue | October 13, 2015 |
| Notice of Permit Issuance | November 3, 2015 |

14. DEP CONTACT

Additional information concerning the permit and proposed schedule for permit issuance may be obtained during normal business hours from:

Marc Harris, P.E.
Department of Environmental Protection
2600 Blair Stone Road, Mail Station 3545
Tallahassee, FL 32399-2400
Telephone Number: (850) 245-8589
Fax Number: (850) 245-8669

15. PROCEDURES FOR THE FORMULATION OF FINAL DETERMINATIONS

a. Public Comment Period

The Department of Environmental Protection proposes to issue a wastewater facility permit to this applicant subject to the aforementioned effluent limitations and conditions. This decision is tentative and open to comment from the public.

Interested persons are invited to submit written comments regarding permit issuance on the draft permit limitations and conditions to the following address:

Department of Environmental Protection
2600 Blair Stone Road
Mail Station 3545
Tallahassee, FL 32399-2400
Attn.: Marc Harris, P.E.

All comments received within 30 days following the date of public notice, pursuant to Rule 62-620.550, F.A.C., will be considered in the formulation of the final decision with regard to permit issuance.

Any interested person may submit written comments on the Department's proposed permitting decision or may submit a written request for a public meeting to the address specified above, in accordance with Rule 62-620.555, F.A.C. The comments or request for a public meeting must contain the information set forth below and must be received in the above named District office of the Department within 30 days of receipt or publication of the public notice. Failure to submit comments or request a public meeting within this time period will constitute a waiver of any right such person may have to submit comments or request a public meeting under Rule 62-620.555, F.A.C.

The comments or request for a public meeting shall contain the following information:

(1) The commenter's name, address and telephone number, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;

(2) A statement of how and when notice of the draft permit was received;

(3) A description of any changes the commenter proposes for the draft permit;

(4) A full explanation of the factual and legal reasons for each proposed change to the draft permit; and

(5) A request that a public meeting be scheduled (if applicable) including a statement of the nature of the issues proposed to be raised at the meeting.

b. Public Meeting

The Department will hold a public meeting if there is a significant degree of public interest in the draft permit or if it determines that useful information and data may be obtained thereby. Public notice of such a meeting shall be published by the applicant at least 30 days prior to the meeting.

If a public meeting is scheduled the public comment period is extended until the close of the public meeting. If a public meeting is held any person may submit oral or written statements and data at the meeting on the Department's proposed action.

c. Issuance of the Permit

The Department will make its decision regarding permit issuance after consideration of all written comments, including comments from the United States Environmental Protection Agency on surface water discharge (NPDES) aspects of the draft or proposed permit; the requirements of Chapter 403, F.S., and appropriate rules; and, if a public meeting is held, after consideration of all comments, statements and data presented at the public meeting. The Department will respond to all significant comments in writing. The Department's response to significant comments will be included in the administrative record of the permit and will be available for public inspection at the above named District office of the Department.

Unless a request for an administrative hearing, or an extension of time to file a petition for an administrative hearing, pursuant to Chapter 120, F.S., as indicated in d. below, is granted, the Department will take final agency action by issuing the permit or denying the permit application. If an administrative hearing is convened, final agency action will be based on the outcome of the hearing.

d. Administrative Hearing

A person whose substantial interests are affected by the Department's proposed permitting decision has the opportunity to petition for an administrative proceeding (hearing) to challenge the Department's decision in accordance with Section 120.57, F.S.

An administrative hearing is an evidentiary proceeding in which evidence is presented by testimony and exhibits before an independent hearing officer. The result of an administrative hearing is the issuance of the hearing officer's recommended order to the Department, including the hearing officers findings of fact, based on the evidence presented at the hearing. The Department will issue a final order, granting or denying the permit, based on the hearing officer's recommended order.

The petition for an administrative hearing must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000, within 14 days of publication of notice of agency action or within 14 days of personal receipt of notice of agency action, whichever occurs first. The petitioner is to mail a copy of the petition to the applicant at the time of filing. Failure to file a petition within this time period will constitute a waiver of any right such person may have to request an administrative determination (hearing) under section 120.57, F.S. The petition is to contain the following information:

(1) The name, address and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(2) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(3) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(4) A statement of the material facts which the petitioner contends warrant reversal or modification of the Department's action or proposed action;
(5) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and
(6) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in the notice of agency action. Persons whose substantial interests will be affected by any decision of the Department on the application have the right to petition to become a party to the proceeding, regardless of their agreement or disagreement with the Department's proposed action indicated in the notice of agency action.

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# FEDERAL REGISTER

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Part II

## Environmental Protection Agency

40 CFR Part 423
Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Proposed Rule

## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Part 423

**[EPA–HQ–OW–2009–0819. FRL–9801–6; EPA–HQ–RCRA–2013–0209]**

**RIN 2040–AF14**

## Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Proposed rule.

**SUMMARY:** EPA is proposing a regulation that would strengthen the controls on discharges from certain steam electric power plants by revising technology-based effluent limitations guidelines and standards for the steam electric power generating point source category. Steam electric power plants alone contribute 50–60 percent of all toxic pollutants discharged to surface waters by all industrial categories currently regulated in the United States under the Clean Water Act. Furthermore, power plant discharges to surface waters are expected to increase as pollutants are increasingly captured by air pollution controls and transferred to wastewater discharges. This proposal, if implemented, would reduce the amount of toxic metals and other pollutants discharged to surface waters from power plants. EPA is considering several regulatory options in this rulemaking and has identified four preferred alternatives for regulation of discharges from existing sources. These four preferred alternatives differ with respect to the scope of requirements that would be applicable to existing discharges of pollutants found in two wastestreams generated at power plants. EPA estimates that the preferred options for this proposed rule would annually reduce pollutant discharges by 0.47 billion to 2.62 billion pounds, reduce water use by 50 billion to 103 billion gallons, cost $185 million to $954 million, and would be economically achievable.

**DATES:** Comments on this proposed rule must be received on or before August 6, 2013. EPA will conduct a public hearing on the proposed pretreatment standards on July 9, 2013 at 1:00 p.m. in the EPA East Building, Room 1153, 1201 Constitution Avenue NW., Washington, DC.

**ADDRESSES:** Submit your comments on the proposed rule, identified by Docket No. EPA–HQ–OW–2009–0819 by one of the following methods:

- *http:www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: OW-Docket@epa.gov,* Attention Docket ID No. EPA–HQ–OW–2009–0819.
- *Mail:* Water Docket, U.S. Environmental Protection Agency, Mail code: 4203M, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Attention Docket ID No. EPA–HQ–OW–2009–0819. Please include three copies.
- *Hand Delivery:* Water Docket, EPA Docket Center, EPA West Building Room 3334, 1301 Constitution Ave., NW., Washington, DC, Attention Docket ID No. EPA–HQ–OW–2009–0819. Such deliveries are only accepted during the Docket's normal hours of operation, and you should make special arrangements for deliveries of boxed information by calling 202–566–2426.

**ADDRESSES:** Submit any comments on the Coal Combustion Residuals Rule issues discussed in Section III.D of this **Federal Register** Notice, identified by Docket ID No. EPA–HQ–RCRA–2013–0209, by one of the following methods:

- *http:www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: RCRA-Docket@epa.gov,* Attention Docket ID No. EPA–HQ–RCRA–2013–0209. In contrast to EPA's electronic public docket, EPA's email system is not an "anonymous access" system. If you send an email comment directly to the Docket without going through EPA's electronic public docket, EPA's email system automatically captures your email address. Email addresses that are automatically captured by EPA's email system are included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket.
- *Fax:* Comments on the CCR rule issue may be faxed to 202–566–0272; Attention Docket ID No. EPA–HQ–RCRA–2013–0209.
- *Mail:* Send your comments on the CCR rule issue to the Hazardous Waste Management System; Disposal Of Coal Combustion Residuals From Electric Utilities, Attention Docket ID No. EPA–HQ–RCRA–2013–0209, Environmental Protection Agency, Mailcode: 5305T, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Please include a total of two copies.
- *Hand Delivery:* Deliver two copies of your comments on the CCR rule issue discussed in this **Federal Register** to the Hazardous Waste Management System; Disposal Of Coal Combustion Residuals From Electric Utilities: Notice, Attention Docket ID No. EPA–HQ–RCRA–2013–0209, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

*Instructions:* Direct your comments to Docket No. EPA–HQ–OW–2009–0819. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or email. The *www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to EPA without going through *www.regulations.gov* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

*Docket:* All documents in the docket are listed in the *www.regulations.gov* index. A detailed record index, organized by subject, is available on EPA's Web site at *http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm.* Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Water Docket in the EPA Docket Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave. 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.

Comments related to EPA's current thinking, as described in Section III.D, regarding how a final RCRA Coal Combustion Residuals rule might be aligned and structured to account for any final requirements adopted under the ELGs for the Steam Electric Power Generating point source category must be submitted to Docket ID Number Docket ID: EPA–HQ–RCRA–2013–0209.

*Pretreatment Hearing Information:* EPA will conduct a public hearing on the proposed pretreatment standards on July 9, 2013 at 1:00 p.m. in the EPA East Building, Room 1153, 1201 Constitution Avenue NW., Washington, DC. No registration is required for this public hearing. During the pretreatment hearing, the public will have an opportunity to provide oral comment to EPA on the proposed pretreatment standards. EPA will not address any issues raised during the hearing at that time but these comments will be included in the public record for the rule. For security reasons, we request that you bring photo identification with you to the meeting. Also, if you let us know in advance of your plans to attend, it will expedite the process of signing in. Seating will be provided on a first-come, first-served basis. Please note that parking is very limited in downtown Washington, and use of public transit is recommended. The EPA Headquarters complex is located near the Federal Triangle Metro station. Upon exiting the Metro station, walk east to 12th Street. On 12th Street, walk south to Constitution Avenue. At the corner, turn right onto Constitution Avenue and proceed to the EPA East Building entrance.

**FOR FURTHER INFORMATION CONTACT:** For technical information, contact Jezebele Alicea-Virella, Engineering and Analysis Division, Telephone: 202–566–1755; Email: *alicea.jezebele@epa.gov.* For economic information, contact James Covington, Engineering and Analysis Division, Telephone: 202–566–1034; Email: *covington.james@epa.gov.*

**SUPPLEMENTARY INFORMATION:**

**Regulated Entities**

| Category | Example of regulated entity | North American industry classification system (NAICS) code |
|---|---|---|
| Industry | Electric Power Generation Facilities—Electric Power Generation | 22111 |
| | Electric Power Generation Facilities—Fossil Fuel Electric Power Generation | 221112 |
| | Electric Power Generation Facilities—Nuclear Electric Power Generation | 221113 |

This section is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this proposed action. Other types of entities that do not meet the above criteria could also be regulated. To determine whether your facility would be regulated by this proposed action, you should carefully examine the applicability criteria listed in 40 CFR 423.10 and the definitions in 40 CFR 423.11 of the rule and detailed further in Section V—Scope/Applicability of the Proposed Rule, of this preamble. If you still have questions regarding the proposed applicability of this action to a particular entity, consult the person listed for technical information in the preceding **FOR FURTHER INFORMATION CONTACT** section.

**How to Submit Comments**

The public may submit comments in written or electronic form. (See the **ADDRESSES** section above.) Electronic comments must be identified by the Docket No. [EPA–HQ–OW–2009–0819] and must be submitted as a MS Word, WordPerfect, or ASCII text file, avoiding the use of special characters and any form of encryption. EPA requests that any graphics included in electronic comments also be provided in hard-copy form. EPA also will accept comments and data on disks in the aforementioned file formats. Electronic comments received on this notice may be filed online at many Federal Depository Libraries. No confidential business information (CBI) should be sent by email.

**Supporting Documentation**

The rule proposed today is supported by a number of documents including:

- Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD), Document No. EPA–821–R–13–002.
- Environmental Assessment for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Environmental Assessment), Document No. EPA–821–R–13–003.
- Benefits and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Document No. EPA–821–R–13–004.
- Regulatory Impact Analysis for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA), Document No. EPA–821–R–13–005.

These documents are available in the public record for this rule and on EPA's Web site at *http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm.*

**Overview**

This preamble describes the terms, acronyms, and abbreviations used in this notice; the background documents that support these proposed regulations; the legal authority for the proposed rule; a summary of the options considered for the proposal; background information; and the technical and economic methodologies used by the Agency to develop these proposed regulations. In addition, this preamble also solicits comment and data from the public. The following outline summarizes the organization of this document.

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## I. Legal Authority

EPA is proposing revisions to the effluent limitations guidelines and standards for the Steam Electric Power Generating Point Source Category (40 CFR 423) under the authority of Sections 301, 304, 306, 307, 308, 402, and 501 of the Clean Water Act, 33 U.S.C. 1311, 1314, 1316, 1317, 1318, 1342, and 1361.

## II. Executive Summary of the Proposed Rule

### *A. Purpose of the Regulatory Action*

The steam electric power generating point source category (i.e., steam electric industry) consists of plants that generate electricity from a process utilizing fossil or nuclear fuel in conjunction with a thermal cycle employing the steam/water system as the thermodynamic medium. The proposed regulations would strengthen the controls on discharges from steam electric power plants by revising the technology-based effluent limitations guidelines and standards that apply to wastewater discharges to surface waters (i.e., direct discharges) and to publicly owned treatment works (i.e., indirect discharges to POTWs). The proposed requirements would reduce the amount of metals and other pollutants discharged to surface waters from power plants.

EPA is considering several options in this rulemaking and has identified four preferred alternatives for regulation of discharges from existing sources. These four preferred alternatives propose the same requirements for most wastestreams but, as described below in Section II.B., differ in the requirements that would be established for discharges associated with two wastestreams from existing sources. EPA also projects different levels of pollutant reduction and cost associated with these alternatives.

EPA estimates that the preferred regulatory options would reduce pollutant discharges by 0.47 billion to 2.62 billion pounds annually, and reduce water use by 50 billion to 103 billion gallons per year. EPA predicts substantial environmental and ecological improvements would result under the preferred regulatory options, along with reduced impacts to wildlife and human health.

The current regulations, which were last updated in 1982, do not adequately address the toxic pollutants discharged from the electric power industry, nor have they kept pace with process changes that have occurred over the last three decades. The development of new technologies for generating electric power (e.g., coal gasification) and the widespread implementation of air pollution controls (e.g., flue gas desulfurization (FGD), selective catalytic reduction (SCR), and flue gas mercury controls (FGMC)) have altered existing wastestreams or created new wastewater streams at many power plants.

As a result, each year the pollutant discharges from this industry are increasing in volume and total mass, and currently account for approximately 50–60 percent of all toxic pollutants discharged into surface waters by all industrial categories currently regulated under the CWA. See Section 3.2.2 of the Environmental Assessment for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Environmental Assessment)—EPA 821–R–13–003. The main pollutants of concern for these discharges include metals (e.g., mercury, arsenic, selenium), nitrogen, and total dissolved solids (TDS). As discussed in Section XIII and the Environmental Assessment report, there are numerous documented instances of environmental impact associated with these power plant discharges, such as harm to human health, harm to aquatic life, contamination of sediment, and detrimental impacts to wildlife. Water quality modeling, in addition to the documented damage cases, corroborates these impacts and indicates that the toxic discharges are a source of widespread aquatic-life impacts, and a source of increased cancer and non-cancer risks in humans, and toxic metal bioaccumulation in wildlife. These discharges also contribute large cumulative nutrient pollutant loads to sensitive watersheds, upsetting the natural balance of such waterbodies as the Great Lakes and the Chesapeake Bay.

This proposed rule would reduce current toxic and other pollutant discharges and their associated impacts. In general, depending on the option, the proposed rule would establish new or additional requirements for wastewaters associated with the following processes and byproducts: Flue gas desulfurization (FGD), fly ash, bottom ash, flue gas mercury control, combustion residual leachate from landfills and surface impoundments, nonchemical metal cleaning wastes, and gasification of fuels such as coal and petroleum coke. In addition to the proposed requirements, as part of this rulemaking EPA is considering establishing best management practices (BMP) requirements that would apply to surface impoundments containing coal combustion residuals (e.g., ash ponds, FGD ponds). EPA is also considering establishing a voluntary program that would provide incentives for existing power plants that dewater and close their surface impoundments containing combustion residuals, and for power plants that eliminate the discharge of all process wastewater (excluding cooling water discharges).

The major provisions of the proposed rule are summarized below. In addition, the proposed requirements and the technologies that serve as the basis for these requirements are explained in more detail in Section VIII of this preamble.

### *B. Summary of Major Provisions of the Proposed Rule*

Depending on the option, EPA is proposing to revise or establish Best Available Technology Economically Achievable (BAT), New Source Performance Standards (NSPS), Pretreatment Standards for Existing Sources (PSES) and Pretreatment Standards for New Sources (PSNS) that apply to discharges of pollutants found in the following wastestreams: FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate from landfills and surface impoundments, nonchemical metal cleaning wastes, and wastewater from flue gas mercury control (FGMC) systems and gasification systems.

EPA has identified four preferred alternatives for regulation of existing discharges in the proposed rule (and it has identified one preferred alternative for regulation of new sources). These four preferred alternatives are summarized below.

*Discharges directly to surface water from existing facilities*—For existing sources that discharge directly to surface water, with the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller), under one preferred alternative for BAT (referred to as Option 3a in this proposal) the proposed rule would establish BAT for wastestreams from these sources that include:

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- "Zero discharge" effluent limit for all pollutants in fly ash transport water and wastewater from flue gas mercury control systems;
- Numeric effluent limits for mercury, arsenic, selenium and TDS in discharges of wastewater from gasification processes;
- Numeric effluent limits for copper and iron in discharges of nonchemical metal cleaning wastes; [1] and
- Effluent limits for bottom ash transport water and combustion residual leachate from landfills and surface impoundments that are equal to the current Best Practicable Control Technology Currently Available (BPT) effluent limits for these discharges (i.e., numeric effluent limits for TSS and oil and grease.

Under a second preferred alternative for BAT (referred to as Option 3b in this proposal), the proposed rule would establish numeric effluent limits for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater from certain steam electric facilities (those with a total plant-level wet scrubbed capacity of 2,000 MW or greater [2]). All other proposed Option 3b requirements are identical to the proposed 3a requirements described above.

Under a third preferred alternative for BAT (referred to as Option 3 in this proposal), the proposed rule would establish numeric effluent limits for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater, with the exception of small generating units (i.e., 50 MW or smaller). All other proposed Option 3 requirements are identical to the proposed Option 3a requirements described above.

Under a fourth preferred alternative for BAT (referred to as Option 4a in this proposal), the proposed rule would establish "zero discharge" effluent limits for all pollutants in bottom ash transport water, with the exception of all generating units with a nameplate capacity of 400 MW or less (for those generating units that are less than or equal to 400 MW, the proposed rule would set BAT equal to BPT for discharges of pollutants found in the bottom ash transport water). All other proposed Option 4a requirements are identical to the proposed Option 3 requirements described above.

In addition, for oil-fired generating units and small generating units (i.e., 50 MW or smaller [3]) that are existing sources and discharge directly to surface waters, under the four preferred alternatives for regulation of existing sources, the proposed rule would establish effluent limits (BAT) equal to the current BPT effluent limits for the wastestreams listed above.

*Discharges to POTWs from existing facilities*—For discharges from existing sources to POTWs, EPA is proposing to establish PSES that are equal to the proposed BAT, with the following exceptions:

- Numeric standards for discharges of nonchemical metal cleaning wastes would be established only for copper; [4]
- Under Options 3a, 3b, and 3 for PSES, EPA is not proposing to establish pretreatment standards for discharges of bottom ash transport water. Under Option 4a, EPA is not proposing to establish pretreatment standards for discharges of bottom ash transport water for generating units with a nameplate capacity of 400 MW or less; [5] and
- Other than the pretreatment standards for nonchemical metal cleaning wastes, EPA is not proposing to establish pretreatment standards for existing sources for discharges from existing oil-fired units and small generating units (i.e., 50 MW or smaller).

*Discharges directly to surface water from new sources*—For all generating units that are new sources and discharge directly to surface waters, including oil-fired generating and small generating units, the proposed rule would establish NSPS that include:

- Numeric standards for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater;
- Maintaining the current "zero discharge" standard for all pollutants in fly ash transport water for direct dischargers;
- Establishing "zero discharge" standards for all pollutants in bottom ash transport water and wastewater from flue gas mercury control systems;
- Numeric standards for mercury, arsenic, selenium, and TDS in discharges of wastewater from gasification processes;
- Numeric standards for mercury and arsenic in discharges of combustion residual leachate; and
- Numeric standards for TSS, oil and grease, copper, and iron in discharges of nonchemical metal cleaning wastes.

*Discharges to POTWs from new sources*—For generating units that are new sources and discharge to POTWs, including oil-fired generating and small generating units, EPA is proposing to establish PSNS that are equal to the proposed NSPS, except that the PSNS would also establish a "zero discharge" standard for all pollutants in fly ash transport water (the current NSPS already includes a zero discharge standard for pollutants in fly ash transport water), and the PSNS would not include numeric standards for TSS, oil and grease, or iron in discharges of nonchemical metal cleaning wastes.

Additional details about the proposed effluent limitations and standards are described in Sections VIII and X of this preamble.

### C. Summary of Costs and Benefits

Table II–1 summarizes the benefits [6] and social costs for the four preferred alternatives for this proposed rule, at 3 percent and 7 percent discount rates. Sections XI and XIV of this preamble provide additional information regarding the costs and the benefits for the proposed rule. Note that although Table II–1 includes the costs associated with BMPs being considered for the proposed rule, it does not similarly include the benefits associated with these BMPs. The BMPs under consideration for the ELGs would reduce the probability of impoundment failures and therefore would be expected to increase the benefits of the proposed ELGs. EPA intends to include such benefits in its analyses for the final rule, should EPA ultimately include the BMPs as part of the final ELGs.

It is important to note that although point estimates are provided in this table, the benefits estimates rely on complex models that include a variety of assumptions, each of which introduces considerable uncertainty into these estimates. This uncertainty is discussed in the Benefits and Cost Analysis for the Proposed Effluent

[1] As described in Section VIII, EPA is proposing to exempt from new copper and iron BAT limitations any existing discharges of nonchemical metal cleaning wastes that are currently authorized without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits applicable to low volume wastes.

[2] Total plant-level wet scrubbed capacity is calculated by summing the nameplate capacity for all of the units that are serviced by wet FGD systems.

[3] As described in Section VIII, one of the preferred options would increase this threshold for purposes of discharges of pollutants in bottom ash transport water only, to 400 MW or less.

[4] As described in Section VIII, EPA is proposing to exempt from new copper PSES standards any existing discharges of nonchemical metal cleaning wastes that are currently authorized without copper limits. For these discharges, the regulations would not specify PSES.

[5] This is because, as explained in Section VII, EPA generally does not establish pretreatment standards for conventional pollutants (e.g., TSS and oil and grease) because POTWs are designed to treat these conventional pollutants.

[6] EPA calculated benefits for some of the options considered for this proposal including Option 3 and Option 4. For others (3a, 3b, and 4a), EPA inferred the benefits based on the pollutant loading reductions (lbs.) relative to the pollutant loading reductions of Option 3 for which EPA analyzed and calculated benefits. See Section XIV for details.

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Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category—EPA 821–R–13–004 (BCA). EPA requests comment on the reasonableness of these assumptions, additional data that may be available to reduce uncertainties in these estimates, and approaches to characterize the remaining uncertainty.

TABLE II–1—TOTAL MONETIZED ANNUALIZED BENEFITS AND COSTS FOR THE PROPOSED RULE

[Millions; 2010$]

| Preferred regulatory alternatives | Total monetized social benefits | | Total social costs | |
|---|---|---|---|---|
| | 3% | 7% | 3% | 7% |
| Option 3a for Existing Sources; Option 4 for New Sources | [a] 139.4 | [a] 104.8 | $185.2 | $164.5 |
| Option 3b for Existing Sources; Option 4 for New Sources | [a] 205.5 | [a] 153.0 | 281.4 | 257.2 |
| Option 3 for Existing Sources; Option 4 for New Sources | $311.7 | $230.4 | 572.0 | 545.3 |
| Option 4a for Existing Sources; Option 4 for New Sources | [a] 482.5 | [a] 424.8 | 954.1 | 914.7 |

[a] EPA did not estimate benefits for Options 3a, 3b and 4a. EPA inferred benefits for Options 3a, 3b, and 4a for illustrative purposes using elements of the more rigorous analysis done to estimate benefits for Options 3 and 4. See Section XIV for details.

## III. Background

### A. Clean Water Act

Congress passed the Federal Water Pollution Control Act Amendments of 1972, also known as the Clean Water Act (CWA), to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters." 33 U.S.C. 1251(a). The CWA establishes a comprehensive program for protecting our nation's waters. Among its core provisions, the CWA prohibits the discharge of pollutants from a point source to waters of the U.S., except as authorized under the CWA. Under section 402 of the CWA, discharges may be authorized through a National Pollutant Discharge Elimination System (NPDES) permit. The CWA also authorizes EPA to establish national technology-based effluent limitations guidelines and standards (ELGs) for discharges from different categories of point sources, such as industrial, commercial, and public sources.

The CWA authorizes EPA to promulgate nationally applicable pretreatment standards that restrict pollutant discharges from facilities that discharge wastewater indirectly through sewers flowing to publicly owned treatment works (POTWs), as outlined in sections 307(b) and (c), 33 U.S.C. 1317(b) and (c). EPA establishes national pretreatment standards for those pollutants in wastewater from indirect dischargers that may pass through, interfere with, or are otherwise incompatible with POTW operations. Generally, pretreatment standards are designed to ensure that wastewaters from direct and indirect industrial dischargers are subject to similar levels of treatment. See CWA section 301(b), 33 U.S.C. 1311(b). In addition, POTWs are required to implement local treatment limits applicable to their industrial indirect dischargers to satisfy any local requirements. See 40 CFR 403.5.

Direct dischargers (i.e., those discharging directly to surface waters) must comply with effluent limitations in NPDES permits. Indirect dischargers, who discharge through POTWs, must comply with pretreatment standards. Technology-based effluent limitations in NPDES permits are derived from effluent limitations guidelines (CWA sections 301 and 304, 33 U.S.C. 1311 and 1314) and new source performance standards (CWA section 306, 33 U.S.C. 1316) promulgated by EPA, or based on best professional judgment (BPJ) where EPA has not promulgated an applicable effluent guideline or new source performance standard (CWA section 402(a)(1)(B), 33 U.S.C. 1342(a)(1)(B)). Additional limitations based on water quality standards are also required to be included in the permit in certain circumstances. CWA section 301(b)(1)(C), 33 U.S.C. 1311(b)(1)(C). The ELGs are established by regulation for categories of industrial dischargers and are based on the degree of control that can be achieved using various levels of pollution control technology.

EPA promulgates national ELGs for major industrial categories for three classes of pollutants: (1) Conventional pollutants (i.e., total suspended solids, oil and grease, biochemical oxygen demand ($BOD_5$), fecal coliform, and pH), as outlined in CWA section 304(a)(4) and 40 CFR 401.16; (2) toxic pollutants (e.g., toxic metals such as arsenic, mercury, selenium, and chromium; toxic organic pollutants such as benzene, benzo-a-pyrene, phenol, and naphthalene), as outlined in section 307(a) of the Act, 40 CFR 401.15 and 40 CFR part 423 appendix A; and (3) nonconventional pollutants, which are those pollutants that are not categorized as conventional or toxic (e.g., ammonia-N, phosphorus, and total dissolved solids).

### B. Effluent Guidelines Program

EPA develops effluent guidelines that are technology-based regulations for a category of dischargers. EPA bases these regulations on the performance of control and treatment technologies. The legislative history of CWA section 304(b), which is the heart of the effluent guidelines program, describes the need to press toward higher levels of control through research and development of new processes, modifications, replacement of obsolete plants and processes, and other improvements in technology, taking into account the cost of controls. Congress has also stated that EPA need not consider water quality impacts on individual water bodies as the guidelines are developed; see Statement of Senator Muskie (October 4, 1972), reprinted in Legislative History of the Water Pollution Control Act Amendments of 1972, at 170. (U.S. Senate, Committee on Public Works, Serial No. 93–1, January 1973.)

There are four types of standards applicable to direct dischargers (plants that discharge directly to surface waters), and two standards applicable to indirect dischargers (plants that discharge to POTWs), described in detail below.

#### 1. Best Practicable Control Technology Currently Available (BPT)

Traditionally, EPA defines BPT effluent limitations based on the average of the best performances of facilities within the industry, grouped to reflect various ages, sizes, processes, or other common characteristics. EPA may promulgate BPT effluent limits for conventional, toxic, and nonconventional pollutants. In specifying BPT, EPA looks at a number of factors. EPA first considers the cost of achieving effluent reductions in relation to the effluent reduction benefits. The Agency also considers the age of equipment and facilities, the

processes employed, engineering aspects of the control technologies, any required process changes, non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate. See CWA section 304(b)(1)(B). If, however, existing performance is uniformly inadequate, EPA may establish limitations based on higher levels of control than what is currently in place in an industrial category, when based on an Agency determination that the technology is available in another category or subcategory, and can be practically applied.

2. Best Conventional Pollutant Control Technology (BCT)

The 1977 amendments to the CWA require EPA to identify additional levels of effluent reduction for conventional pollutants associated with BCT technology for discharges from existing industrial point sources. In addition to other factors specified in section 304(b)(4)(B), the CWA requires that EPA establish BCT limitations after consideration of a two-part "cost reasonableness" test. EPA explained its methodology for the development of BCT limitations in July 9, 1986 (51 FR 24974). Section 304(a)(4) designates the following as conventional pollutants: $BOD_5$, total suspended solids (TSS), fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as an additional conventional pollutant on July 30, 1979 (44 FR 44501; 40 CFR 401.16).

3. Best Available Technology Economically Achievable (BAT)

BAT represents the second level of stringency for controlling direct discharge of toxic and nonconventional pollutants. In general, BAT ELGs represent the best available economically achievable performance of facilities in the industrial subcategory or category. As the statutory phrase intends, EPA considers the technological availability and the economic achievability in determining what level of control represents BAT. CWA section 301(b)(2)(A), 33 U.S.C. 1311(b)(2)(A). Other statutory factors that EPA considers in assessing BAT are the cost of achieving BAT effluent reductions, the age of equipment and facilities involved, the process employed, potential process changes, and non-water quality environmental impacts, including energy requirements and such other factors as the Administrator deems appropriate. CWA section 304(b)(2)(B), 33 U.S.C. 1314(b)(2)(B). The Agency retains considerable discretion in assigning the weight to be accorded these factors. *Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1045 (D.C. Cir. 1978). Generally, EPA determines economic achievability on the basis of the effect of the cost of compliance with BAT limitations on overall industry and subcategory financial conditions. BAT may reflect the highest performance in the industry and may reflect a higher level of performance than is currently being achieved based on technology transferred from a different subcategory or category, bench scale or pilot plant studies, or foreign plants. *American Paper Inst.* v. *Train,* 543 F.2d 328, 353 (D.C. Cir. 1976); *American Frozen Food Inst.* v. *Train,* 539 F.2d 107, 132 (D.C. Cir. 1976). BAT may be based upon process changes or internal controls, even when these technologies are not common industry practice. *See American Frozen Foods,* 539 F.2d at 132, 140; *Reynolds Metals Co.* v. *EPA,* 760 F.2d 549, 562 (4th Cir. 1985); *California & Hawaiian Sugar Co.* v. *EPA,* 553 F.2d 280, 285–88 (2nd Cir. 1977).

4. Best Available Demonstrated Control Technology (BADCT)/New Source Performance Standards (NSPS)

NSPS reflect effluent reductions that are achievable based on the best available demonstrated control technology (BADCT). Owners of new facilities have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. As a result, NSPS should represent the most stringent controls attainable through the application of the BADCT for all pollutants (that is, conventional, nonconventional, and toxic pollutants). In establishing NSPS, EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements. CWA section 306(b)(1)(B), 33 U.S.C. 1316(b)(1)(B).

5. Pretreatment Standards for Existing Sources (PSES)

Section 307(b), 33 U.S.C. 1317(b), of the Act calls for EPA to issue pretreatment standards for discharges of pollutants to POTWs. PSES are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. Categorical pretreatment standards are technology-based and are analogous to BPT and BAT effluent limitations guidelines, and thus the Agency typically considers the same factors in promulgating PSES as it considers in promulgating BAT. The General Pretreatment Regulations, which set forth the framework for the implementation of categorical pretreatment standards, are found at 40 CFR part 403. These regulations establish pretreatment standards that apply to all non-domestic dischargers. See 52 FR 1586 (January 14, 1987).

6. Pretreatment Standards for New Sources (PSNS)

Section 307(c), 33 U.S.C. 1317(c), of the Act calls for EPA to promulgate PSNS. Such pretreatment standards must prevent the discharge of any pollutant into a POTW that may interfere with, pass through, or may otherwise be incompatible with the POTW. EPA promulgates PSNS based on best available demonstrated control technology (BADCT) for new sources. New indirect dischargers have the opportunity to incorporate into their facilities the best available demonstrated technologies. The Agency typically considers the same factors in promulgating PSNS as it considers in promulgating NSPS.

*C. Steam Electric Effluent Guidelines Rulemaking History*

EPA promulgated BPT, BAT, NSPS, and PSNS for the steam electric point source category on October 8, 1974 (39 FR 36186, as amended at 40 FR 7095, February 19, 1975; 40 FR 23987, June 4, 1975) (the "1974 regulations"). The 1974 regulations controlled two basic kinds of discharges from power plants: (1) Thermal discharges (discharges of heat) and (2) pollutant discharges (e.g., discharges of chlorine, polychlorinated biphenyls (PCBs), and suspended solids). EPA promulgated non-thermal pollutant limitations applicable to discharges from the following wastestreams: Once-through cooling water, cooling tower blowdown, bottom ash transport water, fly ash transport water, boiler blowdown, metal cleaning wastes, low volume wastes, and material storage and construction site runoff (including coal pile runoff).

On July 16, 1976, the U.S. Court of Appeals for the Fourth Circuit remanded the following provisions of the 1974 regulations: (1) The thermal limitations, (2) the NSPS for fly ash transport water, (3) the rainfall runoff limitations for material storage and construction site runoff, and (4) the BPT variance clause. All other provisions of the regulations were upheld. *Appalachian Power* v. *Train,* 545 F.2d 1351, 1378 (4th Cir. 1976). EPA repromulgated the coal pile runoff

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regulations in 1980. 45 FR 37432 (June 3, 1980).

EPA promulgated PSES on March 23, 1977 (42 FR 15695) applicable only to indirect discharges of copper present in metal cleaning wastes and PCBs and oil and grease for all wastestreams.

On November 19, 1982, EPA revised and supplemented the effluent limitations guidelines and standards for BCT, BPT, BAT, BADCT/NSPS, PSES, and PSNS (47 FR 52290). Under the 1982 revisions, EPA reserved BCT limitations for all wastestreams and withdrew the BAT limitations for TSS and oil and grease from all wastestreams because those pollutants are properly regulated under BCT, instead of BAT. The rule also made revisions to the following effluent limitations guidelines and standards: BAT and NSPS for once-through cooling water; BAT, NSPS, PSES, and PSNS for cooling tower blowdown; NSPS and PSNS for fly ash transport water; NSPS for bottom ash transport water; and PSES and PSNS for chemical metal cleaning wastes. Finally, the rule revised the definition of low volume wastes to include boiler blowdown and withdrew the separate regulation for boiler blowdown.

*D. Steam Electric Detailed Study*

Section 304 of the CWA requires EPA to periodically review all effluent limitations guidelines and standards to determine whether revisions are warranted. In addition, Section 304(m) of the CWA requires EPA to develop and publish, biennially, a plan that establishes a schedule for reviewing and revising promulgated national effluent guidelines required by Section 304(b) of the CWA. During the 2005 annual review of the existing effluent guidelines for all categories, EPA identified the regulations governing the steam electric power generating point source category for possible revision. At that time, publicly available data reported through the NPDES permit program and the Toxics Release Inventory (TRI) indicated that the industry ranked high in discharges of toxic and nonconventional pollutants. Because of these findings, EPA initiated a more detailed study of the category to determine if the effluent guidelines should be revised. (See "Steam Electric Power Generating Point Source Category: Final Detailed Study Report" (EPA 821–R–09–008) at *http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm)*

During the detailed study, EPA collected data about the industry in several ways. EPA conducted site visits and sampled wastewater at steam electric power plants, and EPA distributed a questionnaire to collect data from nine companies. EPA also reviewed numerous publicly available sources of data and coordinated with and solicited data from EPA program offices and other government organizations (e.g., state groups and permitting authorities), as well as industry, environmental groups, and other stakeholders.

As part of the detailed study, EPA evaluated a range of wastestreams and processes associated with the industry, but it ultimately focused largely on discharges associated with coal ash handling operations and wastewater from FGD air pollution control systems because these sources are responsible for the majority of the toxic pollutants currently discharged by steam electric power plants. EPA also identified several wastestreams that are relatively new to the industry (e.g., carbon capture wastewater), and wastestreams for which there was little characterization data at the time of the detailed study (e.g., gasification wastewater).

During the study, EPA found that the use of wet FGD systems (the kind of systems that generate discharges) to control sulfur dioxide ($SO_2$) air emissions has increased significantly since the last revision of the effluent guidelines in 1982. Moreover, based on industry announcements and modeling conducted for Clean Air Act rulemakings, the use of wet FGD systems is projected to continue to increase in the next decade as power plants take steps to address federal and state air pollution control requirements. EPA also found that FGD wastewaters generally contain significant levels of metals and other pollutants and that treatment technologies are available to treat these pollutants in FGD wastewater; however, most plants use only surface impoundments (e.g., settling ponds) designed primarily to remove suspended solids from FGD wastewater.

EPA found that technologies that do not use water to transport ash are available for handling the fly ash (a combustion residual of fine ash particles entrained in the flue gases) generated at plants, and that such technologies do not generate nor discharge wastewater associated with handling fly ash (i.e., fly ash transport water). Most of these systems are operated at newer electric generating units because the current NSPS regulations, which were promulgated in 1982, prohibit the discharge of pollutants in fly ash transport water. Many older generating units have also converted to dry fly ash handling systems that use air (i.e., pneumatic systems that use air pressure and/or vacuum) to transport the fly ash to storage silos instead of using water to sluice the ash (i.e., pump as a mixture of water and ash) to surface impoundments. As a result, over 80 percent of existing plants use dry fly ash handling. For further information, see Section 4.3.1 of the Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD)—EPA 821–R–13–002.

Additionally, there are technologies available for handling the bottom ash (i.e., a combustion residual of heavier ash particles collected at the bottom of a boiler) that either do not use water to transport the bottom ash away from the boiler or that manage the transport water in a manner (i.e., closed-loop) that eliminates the need to discharge bottom ash transport water to surface water. Neither of these approaches discharge wastewater associated with transporting bottom ash. In fact, some of these technologies do not even generate bottom ash transport water. EPA estimates that by the time the final rule is promulgated, approximately 45 percent of plants will use dry bottom ash handling systems or will not discharge bottom ash transport water.

From information obtained during the detailed study, EPA found that the fly ash and bottom ash transport waters generated from wet systems at coal-fired power plants are created in large quantities and contain significant concentrations of metals, including arsenic, selenium and mercury. Additionally, EPA determined that some of the metals are present primarily in the dissolved phase, and generally are not removed in the surface impoundments that are used to treat these wastestreams to meet the current BPT limits for TSS and oil and grease. Based on the record, EPA found that there are technologies readily available to reduce or eliminate the discharge of pollutants contained in fly ash and bottom ash transport water.

Finally, the information obtained during the study indicates that FGD and ash transport wastewaters contain pollutants that can have detrimental impacts to the environment. EPA reviewed publicly available data and found documented environmental impacts that were attributable to discharges from surface impoundments or discharges from leachate generated from landfills containing combustion residues. EPA found that there are a number of pollutants present in wastewaters generated at coal-fired power plants that can impact the environment, including metals (e.g.,

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arsenic, selenium, mercury), TDS, and nutrients. The primary routes by which combustion wastewater harms the environment are discharges or spills to surface waters, leaching to ground water, and by surface impoundments and constructed wetlands acting as attractive nuisances that increase wildlife exposure to the pollutants contained in the systems. The interaction of combustion wastewaters with the environment has caused a wide range of harm to aquatic life.

Overall, from the detailed study, EPA found that the industry is generating new wastestreams that during the previous rulemakings either were not evaluated or were evaluated to only a limited extent due to insufficient data. Such wastestreams include FGD wastewater, FGMC wastewater, carbon capture wastewater, and gasification wastewaters. EPA also found that these wastestreams, as well as other combustion-related wastestreams at power plants (e.g., fly ash and bottom ash transport water, leachate) contain pollutants in concentrations and mass loadings that are causing documented environmental impacts and that treatment technologies are available to reduce or eliminate the pollutant discharges. For further information, see Section 6 of the Steam Electric Power Generating Point Source Category: Detailed Study is available online at *http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm.*

Based on the findings from the detailed study, which EPA issued in 2009, EPA began taking steps to revise the steam electric power generating effluent limitations guidelines and standards.

*E. Clean Air Act (CAA) Rules*

1. Mercury and Air Toxics Standards (MATS)

When the CAA was amended in 1990, EPA was directed to control mercury and other hazardous air pollutants from major sources of emissions to the air. For power plants using fossil fuels, the amendments required EPA to conduct a study of hazardous air pollutant emissions. CAA Section 112(n)(1)(A). The CAA amendments also required EPA to consider the study and other information and to make a finding as to whether regulation was appropriate and necessary. In 2000, the Administrator found that regulation of hazardous air pollutants, including mercury, from coal- and oil-fired power plants was appropriate and necessary. 65 FR 79825 (Dec. 20, 2000).

EPA published the final MATS rule on February 16, 2012. 77 FR 9304. The rule established standards that will reduce emissions of hazardous air pollutants including metals (e.g., mercury, arsenic, chromium, nickel) and acid gases (e.g., hydrochloric acid, hydrofluoric acid). Steam electric power plants may use any number of practices, technologies, and strategies to meet the new emission limits, including using wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and fabric filters.

2. Cross-State Air Pollution Rule (CSAPR)

EPA promulgated the CSAPR in 2011 to require 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions of sulfur dioxide, nitrogen oxides ($NO_X$) and/or ozone-season $NO_X$ that cross state lines and significantly contribute to ground-level ozone and/or fine particle pollution problems in other states. The emissions of sulfur dioxide, $NO_X$ and ozone-season $NO_X$ addressed by the CSAPR react in the atmosphere to form $PM_{2.5}$ and ground-level ozone and are transported long distances, making it difficult for a number of states to meet the national clean air standards that Congress directed EPA to establish to protect public health. The U.S. Court of Appeals for the D.C. Circuit stayed the CSAPR on December 30, 2011, and on August 21, 2012, issued an opinion vacating the rule and ordering EPA to continue administering the Clean Air Interstate Rule. *EME Homer City Generation, L.P.* v. *EPA,* 696 F.3d 7 (D.C. Cir. 2012). On March 29, 2013, the United States filed a petition asking the Supreme Court to review the D.C. Circuit decision.

3. Greenhouse Gas Emissions for New Electric Utility Generating Units

On April 13, 2012, the EPA proposed new source standards of performance under CAA section 111 for emissions of carbon dioxide for fossil-fuel-fired electricity generating units. 77 FR 22392. The proposed requirements, which apply only to new sources, would require new plants greater than 25 megawatts (MW) to meet an output-based standard of 1,000 pounds of carbon dioxide per MW-hour of electricity generated. EPA based this proposed standard on the performance of natural gas combined cycle technology because EPA and others project that even without this rule, for the foreseeable future, new fossil-fuel-fired power plants will be built with that technology. New coal- or petroleum coke-fired generating units could meet the standard by using carbon capture and storage of approximately 50 percent of the carbon dioxide in the exhaust gas when the unit begins operating or by later installing more effective carbon capture and storage to meet the standard on average over a 30-year period. EPA is evaluating the public comments received on the proposal and has not determined a schedule at this time for taking final action on the proposed rule.

*F. Cooling Water Intake Structures*

Section 316(b) of the CWA, 33 U.S.C. 1326(b), requires that standards applicable to point sources under section 301 and 306 of the Act require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available to minimize adverse environmental impacts. Each year, these facilities withdraw large volumes of water from lakes, rivers, estuaries or oceans for use in their facilities. In the process, these facilities remove billions of aquatic organisms from waters of the United States each year, including fish, fish larvae and eggs, crustaceans, shellfish, sea turtles, marine mammals, and other aquatic life. The most significant effects of these withdrawals are on early life stages of fish and shellfish through impingement (being pinned against intake screens or other parts at the facility) and entrainment (being drawn into cooling water systems).

In November 2001, EPA took final action on regulations for cooling water intake structures at new facilities that have a design intake flow greater than 2 million gallons per day (MGD) and that have at least one cooling water structure that uses at least 25 percent of the water it withdraws for cooling purposes. See 40 CFR 125.81. EPA's requirements provide a two-track approach. Under Track 1, the intake flow at facilities that withdraw greater than 10 MGD is restricted to a level commensurate with the level that may be achieved by use of a closed-cycle recirculating cooling system. Facilities withdrawing greater than 10 MGD located in areas where fisheries need additional protection must also use technology or operational measures to further minimize impingement mortality and entrainment. For facilities with intakes of less than 10 MGD, the cooling water intake structures may not exceed a fixed intake screen velocity and the quantity of intake is restricted. Under Track 2, a facility may choose to demonstrate to the permitting authority that other technologies will reduce the level of adverse environmental impacts to a level that would be achieved under Track 1.

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In March 2011, EPA proposed standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The proposed rule would subject existing power plants and manufacturing facilities withdrawing in excess of 2 MGD of cooling water to an upper limit on the number of fish destroyed through impingement, as well as site-specific entrainment mortality standards. Certain plants that withdraw very large volumes of water would also be required to conduct studies for use by the permit writer in determining site-specific entrainment controls for such facilities. Finally, under the proposed rule, new generating units at existing power plants would be required to reduce the intake of cooling water associated with the new unit, to a level that could be attained by using a closed-cycle cooling system. EPA is continuing analysis and is in the process of addressing comments and finalizing the rule.

*G. Coal Combustion Residuals (CCR) Proposed Rule*

CCRs are residues from the combustion of coal in steam electric power plants and include materials such as coal ash (fly ash and bottom ash) and FGD wastes. CCRs are currently exempt from the requirements of Subtitle C of the Resource Conservation and Recovery Act (RCRA), which governs the disposition and management of hazardous wastes. Potential environmental concerns regarding the management and disposal of CCR include pollution leaching from surface impoundments and landfills contaminating ground water and natural resource damages and risks to human health caused by structural failures of surface impoundments, like that which occurred at the Tennessee Valley Authority's plant in Kingston, Tennessee, in December 2008. The spill, which flooded more than 300 acres of land with CCRs and contaminated the Emory and Clinch rivers, emphasized the need for national standards to address risks associated with the disposal of CCRs.

1. Summary of Proposed CCR Rule

On June 21, 2010, EPA co-proposed regulations that included two approaches to regulating the disposal of CCRs generated by electric utilities and independent power producers. Under one proposed approach, EPA would list these residuals as "special wastes," when destined for disposal in landfills or surface impoundments, and would apply the existing regulatory requirements established under Subtitle C of RCRA to such wastes. Under the second proposed approach, EPA would establish new regulations applicable specifically to CCRs under subtitle D of RCRA, the section of the statute applicable to solid (i.e., non-hazardous) wastes. Under both approaches, CCRs that are beneficially used would remain exempt under the Bevill exclusion.

EPA has not yet taken final action on the proposed CCR regulations. Certain aspects of the CCR rulemaking are discussed in this notice for purposes of better understanding the analyses underlying this proposed revisions to the steam electric generating ELGs. This notice is not proposing anything new or different with respect to the CCR rulemaking (on which the Agency has already solicited public comments) and, therefore, is not opening up that rulemaking to further public comments.

2. Intersection Between the Proposed ELG and Coal Combustion Residuals Rules

This section describes EPA's current thinking on how a final RCRA Coal Combustion Residuals (CCR) rule might be aligned and structured to account for any final requirements adopted under the ELGs for the Steam Electric Power Generating point source category. Consistent with RCRA section 1006(b), EPA seeks to effectively coordinate any final RCRA requirements with the ELG requirements, to minimize the overall complexity of these two regulatory structures, and facilitate implementation of engineering, financial and permitting activities. EPA's approach would also be consistent with Executive Order 13563, "Improving Regulation and Regulatory Review," issued on January 18, 2011, which emphasizes that some "sectors and industries face a significant number of regulatory requirements, some of which may be redundant, inconsistent, or overlapping," and it directs agencies to promote "coordination, simplification, and harmonization." EPA's goal is to ensure that the two rules work together to effectively address the discharge of pollutants from steam electric generating facilities and the human health and environmental risks associated with the disposal of CCRs, without creating avoidable or unnecessary burdens.

In considering how to coordinate the potential requirements between the two rules, EPA is guided by the following policy considerations: first and foremost, EPA intends to ensure that its statutory responsibilities to restore and maintain water quality under the CWA and to protect human health and the environment under RCRA are fulfilled. At the same time, EPA would seek to minimize the potential for overlapping requirements to avoid imposing any unnecessary burdens on regulated entities and to facilitate implementation and minimize the overall complexity of the regulatory structure under which facilities must operate. Based on these considerations, EPA is exploring two primary means of integrating the two rules: (1) through coordinating the design of any final substantive CCR requirements regulatory requirements, and (2) through coordination of the timing and implementation of final rule requirements to provide facilities with a reasonable timeline for implementation that allows for coordinated planning and protects electricity reliability for consumers.

*Coordination of CCR Substantive Requirements with ELG Requirements.* EPA's current thinking is to focus primarily on the areas in which the proposed CCR and ELG rules may regulate or affect the same unit or activity. The scope of the two rules differs; although both of these rules would affect the disposal (*i.e.,* discharge) of coal combustion wastes to and from surface impoundments (*i.e.,* "ponds") at power plants, only the CCR rule would regulate the disposal of CCRs in landfills. Accordingly, in looking at how to coordinate the requirements of the two rules, EPA is primarily focusing on any requirements applicable to surface impoundments, rather than modifications to any requirements applicable to CCR landfills which would be addressed solely under any CCR rule.

One approach is to examine the ways in which EPA anticipates that facilities are likely to modify their operations to comply with the ELG rule, and factor the results of those assessments into EPA's evaluation of whether separate RCRA requirements under the CCR rule are needed to ensure protection of human health and the environment. For example, as described in greater detail in this preamble, the ELG rule could eliminate or reduce certain discharges to surface water, including by controlling or eliminating wastewater that is sent to and discharged from surface impoundments. While the ELG would not compel use of a particular technology, EPA predicts that one possible consequence of the proposed ELG requirements is that some number of facilities will choose to convert their sluicing operations to dry ash-handling systems, and will no longer send such wastes to surface impoundments. EPA is considering how these predictions

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might affect any specific technical requirements under RCRA that could be applicable to CCR surface impoundments. Thus, for instance, to the extent that facilities would no longer need to operate surface impoundments, it is possible that this might affect the time frames (or other requirements) necessary for closure of such impoundments.

However, it is also possible that the requirements established under a final ELG rule could affect the development of any final CCR rule more broadly. Since the close of the comment period on the CCR rule, EPA has received significant new data obtained from a 2010 Information Collection Request (ICR) conducted by EPA's Office of Water for the development of the ELG, which have the potential to affect the risk assessment for the CCR rule. This ICR gathered information from, among others, all 495 electric utility plants that operate coal-fired generating units. In the June 21, 2010 proposal, EPA did not have definitive data about the location, size, or age of the waste management units, nor on the type or composition of the wastes contained in surface impoundments. Consequently, the Agency relied on a 1995 industry report and a number of significant assumptions in the 2010 risk assessment supporting the proposed CCR rule.

These facility-specific data could be used in EPA's risk assessment for any CCR rule in several ways that could significantly affect the results of that assessment. For example, these data could be used to determine the extent to which plumes of contamination leaching from coal ash disposal units into groundwater are intercepted (and reduced) by surface water bodies that exist between a disposal unit and a down-gradient drinking water well. This information has the potential to significantly affect the nature and extent of the risks, and would allow EPA to better estimate the contaminant levels that people would be expected to receive in drinking water, and to better model the likely environmental risks (*e.g.,* to fish and other aquatic life) from such contaminants in surface waters. Because so many of the disposal units (both surface impoundments and landfills) are located next to rivers, the results of the interception analysis could reasonably be expected to have a significant impact on the risk assessment results.

In addition, these data provide information on the location, size, and the type of waste present in hundreds of surface impoundments that were omitted from the data sources on which EPA relied to develop the proposed CCR rule. These impoundments are generally, smaller than the impoundments included in the data used to support the proposed CCR rule, and can differ significantly from the impoundments located at larger facilities. Exclusion of these smaller impoundments could potentially bias the results of the risk assessment, because smaller surface impoundments contain less waste that would be subject to leaching, and any plumes of contamination would likely be smaller. Similarly, these data would allow EPA to refine its analysis of the potential risks from fugitive dust at landfills. Preliminary comparisons of the Office of Water data indicate that currently active portions of landfills are significantly smaller than the landfills identified in the 1995 survey that EPA used in its assessment of the risks from fugitive dust prepared for the proposed rule.

Although a final risk assessment for the CCR rule has not yet been completed, reliance on the data and analyses discussed above may have the potential to lower the CCR rule risk assessment results by as much as an order of magnitude. If this proves to be the case, EPA's current thinking is that, the revised risks, coupled with the ELG requirements that the Agency may promulgate, and the increased Federal oversight such requirements could achieve, could provide strong support for a conclusion that regulation of CCR disposal under RCRA Subtitle D would be adequate.

*Coordination of Timelines for Implementation.* The second component of EPA's approach to integrating any CCR rule with any ELG rule relates to the coordination of compliance and implementation deadlines. EPA's goal is that, consistent with its statutory requirements, the implementation dates for each rule would not require facilities to make decisions without understanding the implications that such decisions would have for meeting any requirements of each rule. Thus, EPA's current approach is to enable a facility to determine whether any changes to its operations are needed to comply with the Steam Electric ELG—and if so, what those might be—before the facility would be required, for example, to decide whether to close or retrofit any surface impoundments pursuant to any CCR rule. For example, assuming that an electric utility relied on a series of surface impoundments or ponds to dispose of wastewater generated at the plant, EPA's current approach would enable the facility—prior to the deadline by which the facility would need to decide whether to retrofit or close those surface impoundments to comply with any CCR rule—to effectively evaluate whether it makes business sense to continue to operate those ponds (with or without any modifications) in light of the requirements of both rules, or whether other changes to facility operations would be more cost-effective.

As it has in this proposed ELG rule, EPA also intends to consider, to the extent permitted by statute, any practical constraints facilities may face in implementing any requirements under both rules (See, for example, Section XVI, addressing implementation issues for the Steam Electric ELGs).

Comments on EPA's current thinking described above on how any final CCR rule might be aligned and structured to account for any final requirements adopted under the ELGs for the Steam Electric Power Generating point source category should be directed to Docket ID Number: EPA–HQ–RCRA–2013–0209. Any comments submitted on this limited set of issues will be considered as part of the CCR rulemaking. By contrast, comments submitted on any other issue related to the CCR rule will be considered "late comments" and EPA will not respond to such comments, nor will they be considered part of the CCR rulemaking record.

## IV. Summary of Data Collection Activities

### *A. Questionnaire for the Steam Electric Power Generating Effluent Guidelines*

A principal source of information used in developing this proposal is the industry responses to a survey, the Questionnaire for the Steam Electric Power Generating Effluent Guidelines, distributed by EPA under the authority of section 308 of the CWA, 33 U.S.C. 1318. EPA designed the industry survey to obtain technical information related to wastewater generation and treatment, and economic information such as costs of wastewater treatment technologies and financial characteristics of potentially affected companies. The Agency consulted with the major industry trade associations to ensure that the industry survey would be useful and to ensure an accurate list of potential recipients. In June 2010, EPA mailed the survey to 733 plants. In general, plants were required to provide responses for the 2009 calendar year. The following describes the questionnaire, the recipient selection process, and the review of the questionnaire responses.

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1. Description of the Industry Survey Components

To obtain information relevant to the rulemaking, EPA's survey consisted of the following nine parts:

- Part A: Steam Electric Power Plant Operations;
- Part B: FGD Systems;
- Part C: Ash Handling;
- Part D: Pond/Impoundment Systems and Other Wastewater Treatment Operations;
- Part E: Wastes from Cleaning Metal Process Equipment;
- Part F: Management Practices for Ponds/Impoundments and Landfills;
- Part G: Leachate Sampling Data for Ponds/Impoundments and Landfills;
- Part H: Nuclear Power Generation; and
- Part I: Economic and Financial Data.

Part A gathered information on all steam electric generating units at the surveyed plant, the fuels used to generate electricity, air pollution controls, cooling water, an inventory of ponds/impoundments and landfills used for combustion residues (including coal, petroleum coke, and oil residues), coal storage and processing, and outfall information. Parts B through I collected economic data and detailed technical information on certain aspects of power plant operations, including requiring some plants to collect and analyze wastewater samples. The process operation sections (Parts B, C, and E) included detailed questions about the types of processes employed, dates that certain types of equipment were installed or plans for future equipment installations, chemical usage, operating characteristics, wastewater generation, pollution prevention activities, and wastewater discharge information.

In Part D of the industry survey, EPA requested detailed information (including diagrams) on the wastewater treatment systems (including chemical usage), discharge flow rates, and operating and maintenance cost data (including chemical usage) (Part D). The ponds/impoundments and landfill questions (Parts F and G) requested information on the size, characteristics, and operation of the ponds/impoundments and landfills located at the facilities. These sections also obtained information on the leachate collection and treatment, and required facilities to collect and analyze samples of untreated and treated leachate from the ponds/impoundments and landfills that receive combustion residues. The survey respondents were required to provide the laboratory analytical results and additional descriptive information about the leachate samples.

For nuclear-fueled generating units, Part H of the industry survey requested general information on the operation of the nuclear units, the wastewaters generated, and the treatment of those wastewaters.

The financial and economic questions (Part I) requested information on the facilities' ownership structure and financial conditions.

The Agency used these data to evaluate process operations and wastewater generation, identify treatment technologies in place, and determine the feasibility of regulatory options for each plant. EPA identified and evaluated the treatment technologies available for treating FGD wastewater and leachate from surface impoundments and landfills, and approaches for ash handling that reduced or eliminated the use of water. EPA also used these data to estimate which plants may incur compliance costs and pollutant removals associated with the various technology control options.

EPA used survey data, along with additional data collected from public sources, to estimate economic impacts on facilities and owning entities under the eight main regulatory options EPA considered for this proposal.

2. Identification of Potential Questionnaire Recipients

The Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy (DOE), collects information on existing electric generating plants and associated equipment to evaluate the current status and potential trends in the industry. EPA used the information available from the 2007 Electric Generator Report (Form EIA–860), and supplemented it with information found in Form EIA–923 and a survey conducted by EPA's Office of Solid Waste and Emergency Response (OSWER), to create a listing of plants that have steam electric power generating activities believed to be subject to the existing Steam Electric Power Generating Effluent Guidelines.

EPA used the EIA data, which contains information on the location of each of the plants (e.g., address, city, state), to create an initial draft of potential questionnaire recipients that EPA shared with industry stakeholders (e.g., the Utility Water Act Group (UWAG)) and interested environmental organizations. UWAG distributed the list to its members and provided feedback to the Agency to correct inaccurate addresses as well as identify plants that were not included or plants that are no longer in operation. Based on the original EIA data and industry feedback, EPA identified 1,197 steam electric generating plants for the survey sample frame (i.e., a list of all steam electric power plants from which the surveyed plants would be selected).

3. Questionnaire Recipient Selection

As a first step in selecting questionnaire recipients, EPA grouped all identified steam electric power plants based on the types of fuels burned at the facility. EPA first classified the generating units into fuel groups based on the primary and secondary energy sources reported in the 2007 Form EIA–860. EPA used the following hierarchy to classify the generating units: Coal, petroleum coke, gas, oil, and nuclear. Generating units that identified either coal or petroleum coke as the primary or secondary energy source were classified as a coal or petroleum coke generating unit. For generating units that did not identify coal or petroleum coke as a primary or secondary energy source, EPA used the primary energy source to classify the generating unit as gas, oil or nuclear. Based on the generating unit classifications, EPA then grouped plants into the fuel categories based on the following hierarchy: Coal, petroleum coke, combination, gas, oil, nuclear. For example, if a plant has one coal unit and five gas units, EPA identified the plant as a coal plant. EPA used the "combination" designation for plants that have at least two generating units that have different unit-level designations (e.g., oil, gas, nuclear), but do not have any coal or petroleum coke units.

Because much of the focus of this proposed rule is on the FGD and ash wastewaters, which are primarily generated at coal- and petroleum coke-fired plants, EPA sent questionnaires to all plants that operate coal- or petroleum coke-fired generating units. For plants without any coal- or petroleum coke-fired generating units (i.e., gas, oil, or nuclear-fueled), EPA sent questionnaires to a statistically selected subset of the identified plants. EPA created four different versions of the questionnaire to send out to plants based on the different parts of the questionnaire:

- Version 1: Parts A through I;
- Version 2: Parts A, B, C, D, H, and I;
- Version 3: Parts A, B, C, D, E, H, and I; and
- Version 4: Parts A, E, H, and I.

In June 2010, EPA mailed the surveys to 733 power plants. EPA mailed Version 1 of the questionnaire to 97 coal- and petroleum coke-fired power plants, which is a subset of the total

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number of coal- and petroleum coke-fired power plants. EPA mailed Version 2 of the questionnaire to the remaining 407 coal- and petroleum coke-fired power plants. EPA mailed Version 3 of the questionnaire to 20 oil-fired plants and 22 plants that burn at least two different types of fuel (e.g., combination plants). EPA mailed Version 4 of the questionnaire to 187 gas-fired and nuclear power plants.

4. Questionnaire Responses

EPA received completed surveys from all 733 questionnaire recipients. A total of 53 plants certified that they were not and did not have the capability to be engaged in steam electric power production, would be retired by December 31, 2011, or did not generate electricity in 2009 by burning any fossil or nuclear fuels.

5. Questionnaire Review

EPA reviewed the surveys for completeness and consistency, using checklists for the review process to help identify potential issues with responses (e.g., data reported in incorrect units, missing responses). After completing the review for each plant, EPA contacted the plant to review the potential issues identified during the review process, if needed. EPA then created a database that contains all survey responses. The questionnaire database in the public record includes all information submitted for which facilities have not asserted that the information is confidential business information (CBI). In some instances, EPA has redacted non-CBI data to prevent the disclosure of other data claimed as CBI.

*B. Engineering Site Visits*

EPA conducted 68 site visits to power plants in 22 states and Italy between December 2006 and February 2013 to collect information about plant operations, process wastewater generation and management practices, and wastewater treatment systems. The primary purpose of these site visits was to evaluate candidate best available technologies and best available demonstrated control technologies, the changes necessary to implement new processes or technologies, and evaluate plants for potential inclusion in EPA's field sampling program. EPA used information provided by UWAG, responses from the detailed study data request, industry survey data, and information learned from contacts with industry representatives to identify site visit candidates. EPA based site visit selection on the type of operations at the plant (e.g., wet FGD systems, wet fly ash or bottom ash handling, gasification), and the plant's approach for minimizing pollutant discharges associated with these operations (e.g., sites employing candidate best available technologies, best available demonstrated control technologies, or processes that reduce or eliminate pollutant discharges.)

EPA collected detailed information from the plants visited, such as the operations associated with wastewater generation, in-process treatment and recycling systems, end-of-pipe treatment technologies, and, if the plant was a candidate for sampling, the logistics of collecting samples. EPA also obtained information regarding zero discharge options associated with the various operations and how the plants could potentially achieve zero discharge for some or all of these operations. EPA prepared site visit reports summarizing the collected information. EPA has included in the public record site visit reports that contain all information collected during site visits for which the plants have not asserted a claim of CBI.

*C. Field Sampling Program*

Between July 2007 and April 2011, EPA conducted a sampling program at 17 different steam electric power plants in the United States and Italy to collect wastewater characterization data and/or treatment performance data associated with FGD wastewater, fly ash and bottom ash wastewater, and wastewater from gasification and carbon capture processes. EPA conducted on-site sampling (i.e., the Agency collected the samples) at 13 of the 17 power plants. Using its authority under CWA section 308, EPA directed seven of these EPA-sampled plants and four additional plants not sampled by EPA to collect additional samples, which were sent to EPA-contracted laboratories for analysis (i.e., CWA 308 monitoring program). In general, EPA used the following criteria to identify the plants included in the sampling program:

- The plant performs steam electric power generation activities representative of steam electric power plants (i.e., the plant's operations are typical of operations observed at other power plants, and therefore, are representative of more than just itself);
- The plant uses coal and/or petroleum coke (the wastestreams of interest and pollutants of concern identified in this rulemaking are primarily associated with plants using these types of fuels); and
- The plant has the wastestreams or treatment technologies of interest.

EPA also obtained sampling data for surface impoundment and landfill leachate collection and treatment systems at 39 plants, as directed by Part G of the Questionnaire for the Steam Electric Power Generating Effluent Guidelines. This leachate sampling is not included in the following description of the field sampling program. See Section 10.2.3 of the TDD for more information on leachate data collected under the industry survey.

EPA's field sampling program began during its detailed study and continued throughout this rulemaking effort. During the study, EPA conducted one- or two-day sampling episodes at six plants to characterize untreated wastewaters generated by coal-fired power plants, as well as to obtain a preliminary assessment of treatment technologies and best management practices for reducing pollutant discharges. The types of wastewaters sampled during the detailed study were untreated and treated FGD wastewater, fly ash wastewater, and bottom ash wastewater.

Upon completing the detailed study, EPA subsequently selected 13 plants to collect additional wastewater characterization data and to evaluate wastewater treatment performance. Through this effort, EPA evaluated 10 FGD wastewater treatment systems; two gasification systems at integrated gasification combined cycle (IGCC) plants; and one pilot-scale carbon capture system. EPA selected these FGD systems because at the time it believed all were among the better performing FGD wastewater treatment systems in the industry, based on information obtained during the site visits and discussions with industry representatives about the design/operation of the treatment system and optimization efforts performed at the plant. In addition, these plants represent geographic variability, different coal types (i.e., bituminous, subbituminous, coal blends), and different operating practices (e.g., baseload vs cycling). The selected IGCC systems and the pilot-scale carbon capture system were the only known systems operating in the U.S. power industry at the time of EPA's field sampling program.

For the 13 plants sampled following completion of the detailed study, samples were collected as follows:

- For seven plants, EPA collected performance data for four consecutive days and the plants also subsequently collected four sets of samples over a four to five month period;
- For four plants, the facility collected performance data for four consecutive days;
- For one plant, EPA collected performance data for three consecutive days; and

• For one plant, the facility collected performance data for one day.

EPA (or the plant) collected representative samples at the influent and effluent of the treatment system being evaluated using a combination of 24-hour composite and grab samples, depending on the sample location and the parameter to be analyzed. EPA analyzed the samples for up to 64 parameters, including conventional pollutants (e.g., TSS, $BOD_5$), nonconventional pollutants (e.g., TDS, nutrients), and metals. For samples collected by EPA, EPA quantified both the total amount of metal and the dissolved portion only. For samples collected by the plants, EPA quantified the total amount of metal. Prior to initiating sampling activities, regardless of who collected the samples, EPA developed sampling plans that detailed the procedures for sample collection, including the pollutants to be sampled, location of the sampling points, and sample collection, preservation, and shipment techniques.

Subsequent to the EPA and industry sampling efforts, EPA prepared a report summarizing the wastewater treatment processes, sampling procedures, and analytical results. EPA has included in the public record these reports containing all information collected for which a facility has not asserted a confidentiality claim or which would indirectly reveal information claimed to be CBI.

*D. EPA and State Sources*

EPA collected information from the Agency's databases and publications, states, and permitting authorities, including the following:

• Information on current and proposed permitting practices for the steam electric industry from a review of selected NPDES permits and accompanying fact sheets;

• Input from EPA and state permitting authorities regarding implementation of the existing Steam Electric Power Generating effluent guidelines;

• Background information on the steam electric industry from documents prepared during the development of the existing Steam Electric Power Generating effluent guidelines (i.e., the 1974 and 1982 rulemakings);

• Information from a survey of the industry conducted for the Cooling Water Intake Structures rulemaking;

• Information from EPA's Office of Air and Radiation (OAR), including Integrated Planning Model (IPM) projections based on recent air rules (i.e., CAIR/CSAPR rule and MATS);

• Information from EPA's Office of Research and Development (ORD) characterizing CCR and the potential leaching of pollutants from CCRs stored or disposed of in landfills and surface impoundments;

• Data provided by the North Carolina Department of Environment and Natural Resources for one plant that operates an anoxic/anaerobic biological treatment system for FGD wastewater; and

• Information collected by EPA's OSWER, regarding surface impoundments or other similar management units that contain CCRs at power plants and other information gathered in support of the proposed rule for regulating CCR under RCRA.

*E. Industry Data*

EPA obtained information on steam electric wastewaters and pollutants directly from the industry through self-monitoring data, as well as NPDES Form 2C data. Specifically, EPA requested self-monitoring data from two power plants to support its calculation of pollutant loading reductions from FGD wastewater treatment technologies and to supplement the data from the EPA sampling program in the development of ELGs for the FGD wastewater. EPA also coordinated with UWAG to create a database of selected NPDES Form 2C data from UWAG's member companies. The NPDES Form 2C database contains information about the outfalls of coal-fired power plants that receive FGD, ash handling, or coal pile runoff wastestreams. EPA received Form 2C data from UWAG for 86 plants in late June 2008 and reviewed the data for use in developing the industry profile, in particular for ash wastewater treatment operations.

*F. Technology Vendor Data*

EPA gathered data from technology vendors through presentations, conferences, meetings, and email and phone contacts to gain information on the technologies used in the industry. EPA also used these contacts with vendors to obtain costs to install and operate the technologies considered as part of the proposed rule. These data informed the development of the industry survey, the technology costs, and the pollutant loadings estimates.

*G. Other Sources*

EPA obtained additional information on steam electric processes, technologies, wastewaters, pollutants, and regulations from sources including trade associations (e.g., UWAG), the Electric Power Research Institute (EPRI), DOE, the U.S. Geological Survey (USGS), and literature and Internet searches. EPA used information provided by the Environmental Integrity Project (EIP), Earthjustice, and the Sierra Club to document known environmental impacts caused by steam electric power plant discharges. In addition, EPA considered information provided in public comments during the effluent guidelines planning process, as well as other contacts with interested stakeholders.

*H. Economic Data*

To conduct cost and economic impact analysis of the proposed regulation, EPA used financial and operational data for steam electric power plants and their parent companies collected through the Steam Electric Questionnaire described in Section IV.A of this preamble.

EPA also used publicly available data describing current operating and business conditions at the steam electric power plants, operators, and parent companies, data describing economic/financial conditions in, and the regulatory environment of, the electric power industry, as well as data on electricity prices and electricity consumption. EPA obtained publicly available data from the following sources: the Department of Energy's EIA (in particular, the EIA 860, 861, and 906/920/923 databases),[7] the U.S. Small Business Administration (SBA), the Bureau of Labor Statistics (BLS), and the Bureau of Economic Analysis (BEA), Securities and Exchange Commission (SEC) Forms 10–K, companies' annual financial reports and press releases, newspapers articles, and Standard & Poor's. Finally, EPA relied on analysis and outputs from the Integrated Planning Model (IPM), a comprehensive electricity market optimization model that can evaluate impacts within the context of regional and national electricity markets (See Section XI).

## V. Scope/Applicability of the Proposed Rule

*A. Facilities Subject to 40 CFR Part 423*

This proposal would establish new requirements for certain plants within the scope of the existing regulations for the steam electric power generating point source category. The proposed requirements would apply to discharges of wastewater associated with the following processes and byproducts: flue gas desulfurization, fly ash, bottom ash, combustion residual leachate, flue gas mercury control, nonchemical metal

[7] EIA–860: Annual Electric Generator Report; EIA–861: Annual Electric Power Industry Database; EIA–923: Utility, Non-Utility, and Combined Heat & Power Plant Database (monthly).

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cleaning wastes, and gasification of fuels such as coal and petroleum coke. EPA is also considering establishing best management practices for surface impoundments receiving coal combustion residuals.

EPA is proposing to correct a typographical error in 40 CFR 423.17(d)(1) by adding a footnote that is missing from the table specifying PSNS for cooling tower blowdown. As is clear from the development document for the 1982 rulemaking, the footnote was intended to appear, as it does in the corresponding table for NSPS, and its omission was an inadvertent mistake, which EPA is now correcting. The footnote proposed to be added reads "No detectable amount" and refers to the effluent standard for 124 of the 126 priority pollutants contained in chemicals added for cooling tower maintenance. (See "Development Document for Final Effluent Guidelines, New Source Performance Standards and Pretreatment Standards for the Steam Electric Power Generating Point Source Category," Document No. EPA 440/1–82/029. November 1982.)

In addition, EPA is proposing three modifications to the applicability provision for the ELGs. These are not substantive modifications and would not alter which generating units are regulated by the ELGs nor impose compliance costs on the industry. Instead, the proposed modifications would remove potential ambiguity present in the current regulatory text by revising the text to more clearly reflect EPA's long-standing interpretation.

First, the applicability provision in the current ELGs states, in part, that the ELGs apply to "an establishment primarily engaged in the generation of electricity for distribution and sale. . . ." 40 CFR 423.10. EPA is proposing to revise that phrase in the applicability provision to read "an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation . . ." This proposed modification would clarify that certain facilities, such as generating units owned and operated by industrial facilities in other sectors (e.g., petroleum refineries, pulp and paper mills) are not included within the scope of the steam electric ELGs. In addition, the proposed modification would clarify that certain municipal-owned facilities, which generate and distribute electricity within a service area (such as distributing electric power to municipal-owned buildings), but which use accounting practices that are not commonly thought of as a "sale" are nevertheless subject to the ELGs. Such facilities have traditionally been regulated by the steam electric ELGs, and EPA believes the proposed modification will improve regulatory clarity.

Second, EPA is proposing a modification to the applicability provision to clarify that fuels derived from fossil fuel are within the scope of the current ELGs. The ELGs currently state, in part, that the ELGs apply to discharges related to the generation of electricity "which results primarily from a process utilizing fossil-type fuels (coal, oil, or gas) or nuclear fuel . . ." 40 CFR 423.10. Because there are a number of fuel types that are derived from fossil fuel, and which thus are fossil fuels themselves, EPA is proposing to revise that phrase in the applicability provision to read "which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (e.g., petroleum coke, synthesis gas), or nuclear fuel . . ."

Third, EPA is proposing to amend the applicability provision to clarify that combined cycle systems are subject to the requirements of the ELGs. The ELGs apply to electric generation processes that utilize "a thermal cycle employing the steam water system as the thermodynamic medium." 40 CFR 423.10. EPA's longstanding interpretation of this provision is that the ELGs apply to all electric generation processes with at least one prime mover that utilizes steam (if they also meet the other factors specified in Section 423.10, including the use of fossil or nuclear fuel). Combined cycle systems, which are generating units composed of one or more combustion turbines operating in conjunction with one or more steam turbines, are subject to the ELGs. The combustion turbines for a combined cycle system operate in tandem with the steam turbines; therefore, the ELGs apply to wastewater discharges associated with both the combustion turbine and steam turbine portions of the combined cycle system.

### *B. Subcategorization*

The CWA requires EPA to consider a number of different factors when developing ELGs for a particular industry category (see BAT factors listed at Section 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B)). For BAT, in addition to the technological availability and economic achievability, these factors are the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors the Administrator deems appropriate. One way EPA may take these factors into account is by dividing a point source category into groupings called "subcategories." Regulating a category by subcategory, where determined to be warranted, ensures that each subcategory has a uniform set of ELGs that take into account technology availability and economic achievability and other relevant factors unique to that subcategory.

The current steam electric ELGs do not divide plants or process operations into subcategories, although they do include different effluent requirements for cooling water discharges from generating units smaller than 25 MW generating capacity. For this proposed rule, EPA evaluated whether different effluent requirements should be established for certain facilities within the steam electric power generating point source category using information from responses to the industry questionnaires, site visits, sampling, and other data collection activities (see Section IV for more details). EPA performed analyses to assess the influence of age, size, fuel type, and geographic location on the wastewaters generated, discharge flow rates, pollutant concentrations, and treatment technology availability at steam electric power plants to determine whether subcategorization was appropriate, as discussed further below.

#### 1. Age of Plant or Generating Unit

EPA analyzed the age of the power plants and the generating units included in the scope of the rule. It determined that the age of the plant by itself does not in general affect the wastewater characteristics, the processes in place, or the ability to install the treatment technologies evaluated as part of this rulemaking. Therefore, EPA did not establish subcategories based on the age of the plant or generating unit for this proposal.

#### 2. Geographic Location

EPA analyzed the geographic location of power plants included in the scope of the rule. It determined that the geographic location of the plant by itself does not affect the wastewater characteristics, the processes in place, or the ability to install the treatment technologies evaluated as part of this rulemaking. During its evaluation, EPA found that wet FGD systems, both wet and dry fly ash handling systems, and both wet and dry bottom ash handling systems are located throughout the United States, as illustrated in Section

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4 of the TDD. Additionally, the location of the plant does not affect the plant's ability to install the treatment technologies evaluated as part of this rulemaking. For example, a plant in the southern United States would be able to install and operate the chemical precipitation and biological treatment system proposed as the BAT technology basis for FGD wastewater. Because of the warm climate, plants in locations such as this may find it necessary to install heat exchangers to keep the FGD wastewater temperature at ideal operating conditions during the summer months. EPA's approach for estimating compliance costs takes such factors into account. Based on the information in the record regarding the current geographic location of the various types of systems generating the wastewaters addressed by this rulemaking and engineering knowledge of the operational processes and candidate BAT/NSPS treatment technologies, EPA determined that subcategories based on plant location are not warranted.

3. Size

EPA analyzed the size (i.e., nameplate generating capacity in MW) of the steam electric generating unit and determined that it can be an important factor influencing the volume of the discharge flow from the plant. Typically, as the size of the generating unit increases, the discharge flows of ash transport water generally increase. In general, this is to be expected because the larger the generating unit, the more fuel it consumes, which generates more ash, and uses more water in the water/steam thermodynamic cycle. Although the volume of the wastewater increases with the size of the generating unit, the pollutant characteristics of the wastewater generally are unaffected by the size of the generating unit and any variability observed in wastewater pollutant characteristics does not appear to be correlated to generating capacity.

As a result of its evaluation, EPA believes that, in certain circumstances, it would be appropriate to apply different limits for a class of existing generating units or plants based on size. Section VIII of this preamble discusses in greater detail EPA's proposal for applying different standards to certain existing units.

4. Fuel Type

The type of fuel (e.g., coal, petroleum coke, oil, gas, nuclear) used to create steam most directly influences the type and number of wastestreams generated. For example, gas and nuclear power plants typically generate cooling water, metal cleaning wastes (both chemical and nonchemical), and other low volume wastestreams, but do not generate wastewaters associated with air pollution control devices (e.g., fly ash and bottom ash transport water, FGD wastewater). Coal, oil, and petroleum-coke power plants may generate all of those wastewaters. The wastestream that is most influenced by fuel selection is the ash transport water because the quantity and quality of ash generated from oil-fired units is different from that generated from coal- and petroleum coke-fired units. Additionally, the quantity and quality of ash differs based on the type of oil used in the boiler. For example, heavy or residual oils such as No. 6 fuel oil generate fly ash and may generate bottom ash, but lighter oils such as No. 2 fuel oil may not generate any ash.

From an analysis of responses to the industry survey, EPA determined that 74 percent of the steam electric units in the industry burn more than one type of fuel (e.g., coal and oil, coal and gas). Some of these plants may burn only one fuel at a specific time, but burn both types of fuels during the year. Other plants may burn multiple fuels at the same time. In cases where facilities burn multiple fuels at the same time, it would be impossible to separate the wastestreams by fuel type.

EPA did not identify any basis for subcategorizing gas-fired and nuclear generating units. These generating units generally manage nonchemical metal cleaning wastes in the same manner as other steam electric generating units, and the proposed requirements for this wastestream would establish limitations and standards that are equal to current BPT limitations for existing direct dischargers.[8] Furthermore, the gas-fired and nuclear generating units do not generate the other six wastestreams addressed by this rulemaking. However, based on responses to the industry survey, there are some oil-fired units that generate and discharge fly ash and/or bottom ash transport water. For these reasons, EPA looked carefully at oil-fired units. As a result, EPA believes that, in certain circumstances, it is appropriate to apply different limits to existing oil-fired generating units. Section VIII of this preamble discusses in greater detail EPA's proposal for applying different standards to certain existing oil-fired units.

## VI. Industry Description

### *A. General Description of Industry*

The steam electric power generating point source category (i.e., steam electric industry) consists of plants that generate electricity from a process utilizing fossil or nuclear fuel in conjunction with a thermal cycle employing the steam/water system as the thermodynamic medium. Based on responses to the industry survey, the Agency estimates that, excluding plants reporting that they would be retired by December 2011, and those plants reporting that they did not operate fossil- or nuclear-fueled units in 2009, there were 1,079 steam electric power plants operating in 2009. These facilities operate an estimated 2,195–2,230 generating units (including combined cycle systems), which have a total nameplate generating capacity of 741,000 MW. (Note: EPA has withheld the precise number of generating units to prevent disclosing CBI.) Table VI–1 shows the estimated number of steam electric generating units broken out by the five primary types of fuels used: coal, petroleum coke, oil, gas, and nuclear.

TABLE VI–1—ESTIMATED NUMBER OF STEAM ELECTRIC GENERATING UNITS AND CAPACITY BY PRIMARY FUEL SOURCE

| Primary fuel source | Number of Generating units | Nameplate capacity (MW) |
|---|---|---|
| Coal | 1,080–1,090 | 328,000–330,000 |
| Petroleum Coke | 12 | 1,000 |
| Oil | 75–100 | 23,900–25,400 |
| Gas | 929 | 282,000 |
| Nuclear | 99 | 104,000 |

[8] As described in Section VIII, EPA is proposing to exempt from new copper and iron BAT limitations any existing discharges of nonchemical metal cleaning wastes that are currently authorized without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits applicable to low volume wastes.

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TABLE VI–1—ESTIMATED NUMBER OF STEAM ELECTRIC GENERATING UNITS AND CAPACITY BY PRIMARY FUEL SOURCE—Continued

| Primary fuel source | Number of Generating units | Nameplate capacity (MW) |
|---|---|---|
| Total Industry | 2,195–2,230 | 741,000 |

Source: Steam Electric Technical Questionnaire Database (DCN SE01958).

As seen from these data, most of the steam electric generating capacity (82 percent) is associated with either coal or gas. Based on survey responses, EPA also found that most plants in the industry have a generating capacity greater than 500 MW and may operate only one generating unit or multiple generating units. Plants of that size account for over 60 percent of all steam electric plants, 70 percent of all electric generating units, and 90 percent of the electric generating capacity.

For coal- and petroleum coke-fired plants, EPA determined that most plants (89 percent) are discharging at least some of their wastewater to surface waters or POTWs. Some plants operate without discharging certain wastewaters (e.g., fly ash transport water, FGD wastewater); however, most plants discharge at least their cooling water. Few of the discharging plants send wastestreams addressed by this rulemaking to POTWs. EPA identified approximately 10 coal- or petroleum coke-fired plants that discharge their FGD wastewater and/or fly ash or bottom ash transport water to POTWs. EPA also found that approximately 11 percent of coal- and petroleum coke-fired power plants do not discharge any wastewater. Most of these zero discharge plants are located in the southwestern United States (e.g., Arizona) and use evaporation ponds to control the wastewater.

*B. Steam Electric Process Descriptions and Wastewater Generation*

In the steam electric process, fuel is fed to a boiler where the fuel is combusted. The hot gases from combustion leave the boiler and pass through air pollution control systems prior to their emission through a stack. The resulting heat from combustion converts water to steam. The high-temperature, high-pressure steam leaves the boiler and enters the turbine generator where it drives the turbine blades as it moves from the high-pressure to the low-pressure stages of the turbine. The lower-pressure steam leaving the turbine enters the condenser, where steam vapor is cooled and condensed back into liquid by cooling water. The water collected in the condenser is sent back to the boiler where it is again converted to steam.

Combined cycle systems consist of combustion turbine electric generating units operating in conjunction with steam turbine electric generating units. Combustion turbines, which typically are similar to jet engines, commonly use natural gas as the fuel. Combined cycle systems feed the fuel into a chamber where it is combusted to generate heat. The combustion exhaust gases are sent directly through a combustion turbine to generate electricity. These exhaust gases still contain useful waste heat as they exit the combustion turbine, so they are directed to heat recovery steam generators to generate steam that is then used to drive a steam turbine, which operates as described above for the steam electric process. The operation of the steam turbine electric generating unit within a combined cycle system is virtually identical to a stand-alone steam electric generating unit, with the exception of the boiler.

IGCC is an electric power generation process that combines gasification technology with combined cycle systems. In an IGCC system, a gasifier converts carbon-based feedstocks (e.g., coal or petroleum coke) into a synthetic gas (syngas) using high temperature and pressure. The syngas is cleaned through multiple process operations and then combusted in a combustion turbine. As with a combined cycle system, a heat recovery steam generator extracts the heat from the exhaust gases to generate steam and drive a steam turbine.

Certain wastewaters generated at steam electric power plants differ based on the fuel used; however, almost all steam electric power plants generate some wastewaters. For example, because all steam electric power plants use a steam water system as the thermodynamic medium, all power plants use cooling water to condense the steam in the system. Additionally, most steam electric power plants have a boiler blowdown stream to purge salts from the water used in the steam water system. Other wastewaters are generated from the use of air pollution control systems and are more directly tied to the type of fuel burned. Coal- and petroleum coke-fired steam electric generating units, and to a lesser degree oil-fired units, generate a flue gas stream that contains large quantities of particulate matter, sulfur dioxide, and nitrogen oxides, which would be emitted to the atmosphere if they were not cleaned from the flue gas prior to emission. Therefore, many of these units are outfitted with air pollution control systems (e.g., particulate removal systems, flue gas desulfurization systems, and $NO_X$ removal systems). Gas-fired units generate fewer emissions of particulate matter, sulfur dioxide, and nitrogen oxides than coal- or oil-fired units, and therefore do not typically operate air pollution control systems to control emissions from their flue gas. EPA determined that the wastewaters associated with these air pollution control systems contain large quantities of metals (e.g., arsenic, mercury, and selenium). Due to increased use of these air pollution control systems in the last decade, and an expected increase in the installation and use of air pollution controls over the next decade, EPA is focusing this rulemaking, in part, on controlling the discharges of these wastewaters.

The information in the remainder of Section VI below describing industry practices generally presents data collected by the industry survey and represents operational conditions for the year 2009. The industry survey represents the most complete source of data available to EPA regarding the operational conditions and wastewater management practices at steam electric power plants. In some cases, where appropriate and as specified below, EPA presents additional information characterizing significant changes to operational practices that have taken place since 2009.

1. Fly Ash and Bottom Ash Systems

Plants use particulate removal systems, which typically consist of either electrostatic precipitators (ESPs) or fabric filters, to collect fly ash and other particulates from the flue gas. The fly ash and other particulates are captured by the ESP or fabric filters and collected in hoppers located underneath the equipment. From the collection hoppers, the fly ash is either

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pneumatically transferred as dry ash to silos for temporary storage or transported (sluiced) with water to a surface impoundment (i.e., ash pond). The water used to transport the fly ash to the surface impoundment is usually discharged to surface water as overflow from the impoundment after the fly ash has settled. Of the coal- and petroleum coke-fired steam electric generating units that generate fly ash, 66 percent operate dry fly ash transport systems, while 15 percent operate both wet and dry fly ash transport systems. The remaining 19 percent operate only wet fly ash transport systems, although not all of these plants discharge their fly ash transport water. In cases where a unit has both wet and dry handling operations, the wet handling system is typically used as a backup to the dry system.

Fly ash transport water is one of the largest volume flows for coal-fired power plants. Many wet transport plants (i.e., 45 percent of plants with wet fly ash systems) sluice their fly ash continuously, and 68 percent of wet transport plants sluice their fly ash at least 12 hours per day. Based on responses to the industry survey, the average fly ash transport water flow rate is 2.4 million gallons per day (MGD). EPA estimates that the steam electric industry discharged a total of 81.1 billion gallons of fly ash transport water to surface water in 2009.

In addition to the particulate removal system for removing fly ash from the flue gas, there are also systems for handling the bottom ash that accumulates at the bottom of the furnace. The bottom ash consists of the heavier ash particles that could not be entrained in the flue gas and fall to the bottom of the furnace. In most furnaces, the hot bottom ash is quenched in a water-filled hopper. Ash from the hopper is then fed into a conveying line where it is diluted into slurry and pumped to an impoundment or dewatering bins. The ash sent to a dewatering bin is separated from the transport water and then disposed. For both of these systems, the water used to transport the bottom ash to the impoundment or dewatering bins is usually discharged to surface water as overflow from the systems, after the bottom ash has settled. Alternatively, some furnaces are fitted with mechanical drag systems where the bottom ash drops into a water-filled trough, but the ash is removed using a submerged mechanical drag conveyor that drags the bottom ash out of the furnace. At the end of the trough, the drag chain reaches an incline, which dewaters the bottom ash by gravity, draining the water back to the trough as the ash moves up the conveyor. The bottom ash is often dumped into a nearby bunker for temporary storage. As the bottom ash continues dewatering in the nearby bunker, water that drains from the system may be discharged; however, EPA does not consider this water from the bunker to be bottom ash transport water because the mechanical conveyor, and not the water, is the transport mechanism that moves the ash away from the boiler. Instead, the wastewater draining from the bunker would be low volume wastes. Over 65 percent of the units generating bottom ash operate wet bottom ash transport systems, approximately 30 percent operate systems that eliminate the use of transport water, and approximately 5 percent operate both. Plants that have both wet and dry handling operations typically use the wet handling system as a backup to the dry system. Some plants that have wet bottom ash systems operate them in a manner that does not discharge to surface water.

Bottom ash transport water is an intermittent stream from steam electric units. The bottom ash transport water flow rates are typically not as large as the fly ash transport water flow rates; however, bottom ash transport water is still one of the larger volume flows for steam electric plants. Based on responses to the industry survey, the average bottom ash transport water flow rate is 1.8 MGD. EPA estimates that the steam electric industry discharged a total of 157 billion gallons of bottom ash transport water in 2009.

Power plants that generate fly ash and bottom ash can either dispose of it in landfills or surface impoundments, or can use it in applications such as cement or concrete manufacturing. Power plants have used the ash in many applications that preclude the need to dispose of the ash in landfills/impoundments.

2. FGD Systems

FGD systems remove sulfur dioxide from the flue gas so that it is not emitted into the air. There are both wet and dry FGD systems. Dry FGD systems generally inject an aqueous sorbent (e.g., lime) into a spray dryer such that the water present evaporates as it contacts the hot flue gas. The sulfur dioxide in the flue gas reacts with the lime as it dries and results in a dry particulate product that is captured in a downstream fabric filter; no wastewater is generated from the dry FGD process. In wet FGD systems, the flue gas stream comes in contact with a liquid stream containing a sorbent, typically lime or limestone, which is used to effect the mass transfer of pollutants from the flue gas to the liquid stream. This process not only transfers the sulfur dioxide from the flue gas to the liquid stream, but other pollutants (e.g., metals) as well. During this process, the lime/limestone and sulfur dioxide react to form calcium sulfite or calcium sulfate (i.e., gypsum), depending on the oxidation level of the FGD system. Gypsum is a marketable product, and as such, plants that generate gypsum generally sell (or give away) the material for use in building materials (e.g., wallboard). Plants that do not generate gypsum, or only partially oxidize the calcium sulfite, generally dispose of their FGD solids in landfills or surface impoundments. Those plants that produce a saleable product, such as gypsum, may rinse the product cake to reduce the level of chlorides in the final product. This wash water may be reused or discharged to a receiving water or POTW. Additionally, both calcium sulfite and gypsum typically require dewatering prior to sale/disposal and this dewatering process also generates a wastewater stream that may be reused or discharged. The FGD system generally requires a blowdown stream to purge chlorides to prevent scaling and corrosion of the FGD equipment.

FGD wastewater is typically an intermittent stream generated by coal-fired power plants operating wet FGD systems. Based on responses to the industry survey, the average FGD wastewater flow rate is 559,000 gallons per day (gpd). EPA estimates that the steam electric industry discharged a total of 23.7 billion gallons of FGD wastewater in 2009.

Based on the responses to the industry survey, there are approximately 401 FGD systems either currently operating or that will be installed by January 1, 2014.[9] Approximately 90 of the currently operating FGD systems are dry systems that do not generate any wastewater streams, while 311 systems are wet FGD systems.[10]

3. Flue Gas Mercury Control (FGMC) Systems

FGMC systems remove mercury from the flue gas, so that it is not emitted into the air. According to the responses to the industry survey, two main types of

[9] Because EPA expects to take final action on this rule in 2014, EPA used 2014 as the baseline year for its analysis. EPA is considering using alternative dates, such as 2022 which may better reflect the implementation timeframe for the ELG, for the baseline year for its analyses for the final rule.

[10] This is not the number of steam electric power plants with wet FGD systems. An individual steam electric power plant may operate one or more FGD systems.

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systems are currently in use in the industry: (1) Addition of oxidizers to the coal prior to combustion, whereby the oxidized mercury is removed in the wet FGD system; and (2) injection of activated carbon into the flue gas which adsorbs the mercury and is captured in a downstream particulate removal system.

The use of the oxidizers does not generate a new wastewater stream; however, it may increase the concentration of mercury in the FGD wastewater because the oxidized mercury is more easily removed by the FGD system. The activated carbon injection system does have the potential to generate a new wastestream at a plant, depending on the location of the injection. If the injection occurs upstream of the primary particulate removal system, then the mercury-containing carbon (i.e., FGMC waste) is collected and handled the same way as the fly ash. Therefore, if the fly ash is wet sluiced, then the FGMC wastes are also wet sluiced and likely sent to the same surface impoundment. In this case, adding the FGMC wastes to the fly ash can increase the amount of mercury in the fly ash transport water. If the injection occurs downstream of the primary particulate removal system, then the plant will need a secondary particulate removal system (typically a fabric filter) to capture the FGMC wastes. Plants typically inject the carbon downstream of the primary particulate collection system if they plan to market the fly ash because the carbon in FGMC wastes can make the fly ash unmarketable. In this situation, the FGMC wastes, which would be collected with some carry-over fly ash, could be handled either wet or dry.

Based on the responses to the industry survey, in 2009 there were approximately 120 operating FGMC systems, with an additional 40 planned for installation by 2020. Approximately 90 percent of the currently operating FGMC systems are dry systems that do not generate or affect any wastewater streams. Approximately six percent of the currently operating systems are wet systems. For the remaining 4 percent of the systems, the type of handling system (e.g., wet or dry handling) is unknown.

4. Combustion Residual Leachate From Surface Impoundments and Landfills

Combustion residuals comprise a variety of wastes from the combustion process, including fly ash, bottom ash (which includes boiler slag), and FGD solids (e.g., gypsum and calcium sulfite), which are generally collected by or generated from the air pollution control technologies. These combustion residuals may be stored at the plant in on-site landfills or surface impoundments (i.e., ponds). Based on industry survey results, there are approximately 228 plants that operate combustion residual landfills and 264 plants that operate combustion residual surface impoundments. Some plants operate both landfills and impoundments, while other plants may operate only one or the other, or neither type of disposal unit.

Leachate is the liquid that drains or leaches from a landfill or surface impoundment. Most landfills have a system to collect the leachate and some impoundments have leachate collection systems. The two sources of leachate are precipitation that percolates through the waste deposited in the landfill/impoundment and the liquids produced from the combustion residuals placed in the landfill/impoundment. In addition to leachate, stormwater that enters the impoundment or contacts and flows over the landfill would be contaminated with combustion residual pollutants. Leachate and contaminated stormwater contain heavy metals and other contaminants through the contact with the combustion residuals.

Some landfills and surface impoundments are lined. In a lined landfill/impoundment, the leachate collected in the liner typically flows through a collection system consisting of ditches and/or underground pipes. From the collection system, the leachate is transported to an impoundment (e.g., collection pond). The stormwater collection systems typically consist of one or more small impoundments or collection ponds. The leachate and stormwater may be treated in separate impoundments or combined together. Some plants discharge the effluent from these leachate impoundments, while other plants send the leachate impoundment effluent to another impoundment handling the ash transport water or other treatment system (e.g., constructed wetlands). Unlined impoundments and landfills usually do not collect leachate thereby leaving the leachate to potentially migrate to nearby ground waters, drinking water wells, or surface waters.

Based on responses to the industry survey, approximately 100 plants collect landfill leachate from approximately 110 existing (i.e., active or inactive) landfills containing CCR, while approximately 50 plants collect leachate from existing CCR surface impoundments. Another 40 plants collect leachate from both types of systems.

Leachate is an intermittent stream whose flow rate, frequency, and duration are generally determined by weather conditions. For this reason, leachate flow rates can vary greatly for a plant, as well as varying from one plant to another. Additionally, there are differences in flow rates depending on whether the landfill or surface impoundment is active/inactive or retired. Retired landfills or surface impoundments tend to have lower flow rates because they have been capped or closed and, therefore, are not open to the atmospheric rainfall. Based on the industry survey, the average active/inactive landfill leachate flow rate was approximately 60,000 gpd. EPA estimates that the steam electric industry discharged approximately 6.2 billion gallons of leachate in 2009.

5. Gasification Processes

As described above, IGCC plants uses a carbon-based feedstock (e.g., coal or petroleum coke) and subject it to high temperature and pressure to produce a synthetic gas ("syngas") which is used as the fuel for a combined cycle generating unit. In these IGCC plants, after the syngas is produced, it undergoes cleaning prior to combustion. The cleaning processes can involve any number of the following processes:

- Water scrubbing;
- Carbonyl-sulfide hydrolysis;
- Acid gas removal (stripping); and
- Sulfur recovery.

The wastewater generated by these processes, along with any condensate generated in flash tanks, slag handling water, or wastewater generated from the production of sulfuric acid, are referred to as "grey water" or "sour water," and require treatment prior to reuse or discharge.

EPA identified two plants currently operating IGCC units, and a third IGCC unit is scheduled to begin operation this year. A fourth IGCC power plant is under construction and is scheduled to begin commercial operation in 2014.

The gasification processes generally operate continuously and, therefore, generate most of the individual gasification wastestreams continuously. Based on the information collected during EPA's sampling program, EPA determined the gasification wastewater transferred to the treatment system ranged from 6,000 to 109,000 gpd, with an average flow of 66,000 gpd.

6. Metal Cleaning Wastes

The ELGs define metal cleaning waste as "any wastewater resulting from cleaning [with or without chemical cleaning compounds] any metal process equipment, including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning." 40

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CFR 423.11. Plants use chemicals to remove scale and corrosion products that accumulate on the boiler tubes and retard heat transfer. The major constituents of boiler cleaning wastes are the metals of which the boiler is constructed, typically iron, copper, nickel, and zinc. Boiler firesides are commonly washed with a high-pressure water spray against the boiler tubes while they are still hot. Fossil fuels with significant sulfur content will produce sulfur oxides that adsorb on air preheaters. Water with alkaline reagents is often used in air preheater cleaning to neutralize the acidity due to the sulfur oxides, maintain an alkaline pH, and prevent corrosion. The types of alkaline reagents used include soda ash, caustic soda, phosphates, and detergent.

The frequency of metal cleaning activities can vary depending on the type of cleaning operation and individual plant practices. Some operations occur as often as several times a day, while others occur once every several years. Soot blowing, the process of blowing away the soot deposits on furnace tubes, generally occurs once a day, but some units do this as often as several hundred times a day. While 83 percent of units responding to the industry survey use steam or service air to blow soot, some plants may generate wastewater streams. Air heater cleaning is another frequent cleaning activity. Sixty-six percent of the units perform this operation at least once every two years, while other units perform this cleaning task very infrequently, only once every 40 years. Generally, plants use raw or potable water to clean the air heater.

The following types of metal cleaning wastes were reported in responses to the industry survey:

- Air compressor cleaning;
- Air-cooled condenser cleaning;
- Air heater cleaning;
- Boiler fireside cleaning;
- Boiler tube cleaning;
- Combustion turbine cleaning (combustion portion and/or compressor portion);
- Condenser cleaning;
- Draft fan cleaning;
- Economizer wash;
- FGD equipment cleaning;
- Heat recovery steam generator cleaning;
- Mechanical dust collector cleaning;
- Nuclear steam generator cleaning;
- Precipitator wash;
- SCR catalyst soot blowing;
- Sludge lancing;
- Soot blowing;
- Steam turbine cleaning; and
- Superheater cleaning.

7. Carbon Capture and Storage Systems

The industry is investigating carbon capture and storage systems to remove carbon dioxide ($CO_2$) from the flue gas. Many steam electric power plants are considering alternatives available for reducing $CO_2$ emissions; however, according to the industry survey responses, there are no full-scale carbon capture systems currently operating. EPA obtained information about two pilot-scale systems that operated in recent years; however, neither of these systems is currently operating. Additionally, several plants reported in their survey responses that they are planning to install a pilot-scale carbon capture system and some plants reported plans to install full-scale systems by 2020.[11]

There are three main approaches for capturing the $CO_2$ associated with generating electricity: Post-combustion, pre-combustion, and oxyfuel combustion.

- In post-combustion capture, the $CO_2$ is removed after combustion of the fossil fuel.
- In pre-combustion capture, the fossil fuel is partially oxidized, such as in a gasifier. The resulting syngas (CO and $H_2$) is processed to create $CO_2$ and more $H_2$, and the resulting $CO_2$ can be captured from a relatively pure exhaust stream before combustion takes place.
- In oxy-fuel combustion, also known as oxy-combustion, the fuel is burned in oxygen instead of air. The flue gas consists of mainly $CO_2$ and water vapor; the latter condenses through cooling. The result is an almost pure $CO_2$ stream that can be transported to the sequestration site and stored.

Based on preliminary information regarding these technologies, EPA believes they may result in new wastewaters at steam electric power plants. However, as these technologies are currently in the early stages of research and development and/or pilot testing, the industry has little information on the potential wastewaters generated from carbon capture processes. As part of its sampling program, EPA obtained analytical data associated with two wastestreams generated from a post-combustion carbon capture system. Because of the small size of the pilot-scale system, the plant transferred the wastewater off site for treatment.

*C. Control and Treatment Technologies*

EPA evaluated the technologies available to control and treat wastewater generated by the steam electric industry. Individual plants may use one or more processes that generate wastewater streams. They may treat these wastestreams separately or in various combinations. For this reason, EPA evaluated available technologies for each major wastestream separately.

1. FGD Wastewater

EPA identified 145 steam electric power plants that generate FGD wastewater. Of these, 117 plants (81 percent) discharge FGD wastewater after treatment using one or more of the following technologies:

- *Surface Impoundments:* Surface impoundments (e.g., settling ponds), designed to remove particulates from wastewater by means of gravity, may be configured as one impoundment or a series of impoundments. Impoundments are typically sized to allow for a certain residence time to enable the suspended solids to settle to the bottom. The impoundments are also designed to have sufficient capacity to allow for temporary storage or permanent disposal of the settled solids. Surface impoundments are not designed to remove dissolved metals. Plants may add treatment chemicals to the impoundment, typically to adjust pH before final discharge.

There are 63 plants (54 percent of the discharging plants) that use surface impoundments as the only type of treatment for FGD wastewaters. Most (49) of these plants also combine their FGD wastewater with other plant wastewater while the remainder (14) use impoundments to treat FGD wastewater alone. Additional plants (above and beyond the 63 plants described in the preceding sentences) also use surface impoundments to remove suspended solids prior to a more advanced treatment process, such as chemical precipitation or biological treatment.

- *Chemical Precipitation:* Some plants use chemical precipitation systems instead of or in addition to surface impoundments. Chemical precipitation treatment is a tank-based system in which chemicals are added to enhance the removal of suspended solids and dissolved solids, particularly certain dissolved metals. The dissolved metals amenable to chemical precipitation treatment are removed from aqueous solutions by converting soluble metal ions to insoluble metal hydroxides or sulfides. The precipitated solids are then removed from solution by coagulation/flocculation followed by clarification and/or filtration. Chemical reagents such as lime (calcium hydroxide), sodium hydroxide, and ferric chloride are used to adjust the pH

[11] In order to protect CBI claims, EPA cannot provide specific numbers.

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of the water to reduce the solubility of the metal(s) targeted for removal.

Some plants also use sulfide chemicals (e.g., organosulfides or sodium sulfide) to precipitate and remove heavy metals, including mercury. Sulfide precipitation is more effective than hydroxide precipitation in removing mercury because mercury sulfides have lower solubilities than mercury hydroxides. Other metal sulfide compounds also typically have lower solubilities than metal hydroxide compounds. Because sulfide precipitation is more expensive than hydroxide precipitation, plants usually use hydroxide precipitation first to remove most of the metals, and then sulfide precipitation to remove the remaining low solubility metals. This configuration overall requires less sulfide, thereby reducing the expense for the sulfide treatment chemicals.

EPA identified 40 plants (34 percent of the discharging plants) that treat their FGD wastewater using chemical precipitation (in some cases, also employing additional treatment steps such as biological treatment). Lime is the most commonly used treatment chemical to perform the pH adjustment needed for these systems. Sulfide precipitation, alone or in combination with hydroxide precipitation, is used by 33 plants (28 percent of the discharging plants). Most plants operating chemical precipitation treatment systems for FGD wastewater employ ferric chloride addition (i.e., iron coprecipitation) as part of the treatment process.

• *Biological Treatment:* Some steam electric power plants also treat FGD wastewater using biological treatment systems. An anoxic/anaerobic biological system being used in the industry is effective at removing both metals (total and dissolved) and nutrients. This system is designed to significantly reduce nitrogen compounds and selenium. These fixed-film bioreactors are designed for plug flow operation and have zones of differing oxidation potential that allow for nitrification and denitrification of the wastewater and reduction of metals, such as selenium. The system alters the form of selenium, reducing selenate and selenite to elemental selenium, which is then captured by the biomass and retained in treatment system residuals.

EPA identified five plants that operate the fixed-film anoxic/anaerobic biological treatment systems to treat FGD wastewater, and another plant recently installed a suspended growth biological treatment system that targets removal of selenium and other metals.[12] Four of these six plants also operate chemical precipitation systems prior to the biological treatment system. There are also at least four other plants that operate aerobic/anaerobic sequencing batch reactors to treat FGD wastewater that has already undergone chemical precipitation. These systems are capable of removing organics and nutrients, but are not operated in a manner to remove selenium or other metals.

• *Vapor-Compression Evaporation System:* This type of system uses a falling-film evaporator (or brine concentrator) to produce a concentrated wastewater stream and a distillate stream. With pretreatment, such as chemical precipitation and softening, brine concentrators can reduce wastewater volumes by 80 to 90 percent. Plants can further process the concentrated wastewater stream in a crystallizer or spray dryer, which evaporates the remaining water to generate a solid waste product and potentially a condensate stream. The distillate and condensate streams may be reused within the plant or discharged to surface waters. EPA identified two U.S. plants and four Italian plants that treat FGD wastewater using vapor-compression evaporation. A third U.S. plant is currently installing a vapor-compression evaporation treatment system; it is scheduled to be operational by the end of 2013.

• *Constructed Wetlands:* Constructed wetlands are engineered systems that use natural biological processes involving wetland vegetation, soils, and microbial activity to reduce the concentrations of metals, nutrients, and TSS in wastewater. High temperature, chemical oxygen demand (COD), nitrates, sulfates, boron, and chlorides in wastewater can adversely affect constructed wetlands performance. To overcome this, plants typically dilute FGD wastewater with service water (i.e., supply water used widely throughout the plant for a variety of uses) before it enters a constructed wetland.

EPA identified three plants that treat their FGD wastewater using constructed wetlands. The constructed wetlands used to treat FGD wastewater typically are designed to treat only the FGD wastewater (and the service water used for dilution); however, because these systems are open to the environment, they also receive stormwater from the surrounding areas.

[12] A seventh plant is scheduled to begin operating a biological treatment system for selenium removal in 2014. This plant is not included in this summary of biological treatment systems.

• *Other Technologies:* EPA identified several other technologies that have been evaluated for treatment of FGD wastewater, including iron cementation, reverse osmosis, absorption or adsorption media, ion exchange, and electro-coagulation. Other technologies under laboratory-scale study include polymeric chelates, taconite tailings, and nano-scale iron reagents. Most of these technologies have been evaluated only as pilot-scale studies; however, two of these technologies are currently operating at full-scale to treat FGD wastewater. One plant operates a full-scale ion exchange system that selectively targets the removal of boron, in conjunction with a chemical precipitation treatment stage to remove mercury and other metals, and an anaerobic biological treatment stage to remove selenium. Another plant treats the FGD wastewater with chemical precipitation, followed by a full-scale treatment unit that uses cartridge filters in combination with two sets of adsorbent media specifically designed to enhance removals of metals. After passing through three sets of cartridge filters (3-micron, 1-micron, and then 0.2-micron), the FGD wastewater passes through a carbon-based media that adsorbs mercury, and then through a ferric hydroxide-based media that adsorbs arsenic, chromium, and other metals. The adsorbent media reportedly achieves a maximum effluent concentration of 14 parts per trillion for mercury.

• *Design/Operating Practices Achieving Zero Discharge:* EPA identified four design/operating practices available enabling plants to eliminate the discharge of wastewater from wet FGD systems: 1) Several variations of complete recycle, 2) evaporation ponds, 3) conditioning dry fly ash, and 4) underground injection. Of the 145 plants that generate wastewater from FGD processes, 28 plants (19 percent) operate in such a manner that they do not discharge wastewater to surface waters or POTWs. Many of the plants in the southwestern United States that generate FGD wastewater use evaporation ponds that do not discharge.

2. Fly Ash Transport Water

Fly ash separated from boiler exhaust by electrostatic precipitators (ESPs) or fabric filters is collected in hoppers located underneath the equipment. From the collection hoppers, the fly ash is either transferred as dry ash to silos for temporary storage or transported (sluiced) with water to a surface impoundment (i.e., ash settling pond). Plants that generate fly ash transport

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water use surface impoundments to manage the wastewater. EPA has not identified any facilities using more advanced treatment, such as chemical precipitation or biological treatment, to treat fly ash transport water. EPA identified 393 generating units (at 144 plants) that wet sluice at least a portion of fly ash. Wet sluicing systems use water-powered hydraulic vacuums to withdraw fly ash from the hoppers. The ash is pulled to a separator/transfer tank, combined with sluicing water, and pumped to the surface impoundment to remove particulates from the wastewater by means of gravity, before discharge to a receiving stream.

Many coal and oil-fired power plants design their fly ash handling systems to minimize or eliminate the discharge of fly ash handling transport water. Such approaches include:

- *Wet Vacuum Pneumatic System:* These systems use water-powered hydraulic vacuums for the initial withdrawal of fly ash from the hoppers, similar to wet sluicing systems. Instead of sluicing the ash to a surface impoundment, these systems capture the ash in a filter-receiver (bag filter with a receiving tank) and then deposit the dry ash in a silo.
- *Dry Vacuum Pneumatic System:* These systems use a mechanical exhauster to move air, below atmospheric pressure, to pull the fly ash from the hoppers and convey it directly to a silo. The fly ash empties from the hoppers in to the conveying system via a material handling valve.
- *Pressure System:* These systems use air produced by a positive displacement blower to convey ash directly from the hopper to a silo. Each ash collection hopper is equipped with airlock valves that transfer the fly ash from low pressure to high pressure in the conveying line. The airlock valves are installed at the bottom of the hoppers and require a significant amount of space. Retrofit installations of pressure ash handling systems may require raising the bottom of the hopper.
- *Combined Vacuum/Pressure System:* These systems use a dry vacuum system to pull ash from the hoppers to a transfer station, where the ash is transferred from the vacuum (low pressure) to ambient pressure. From the transfer station, the fly ash is transferred via airlock valves to a high pressure conveying line. A positive displacement blower conveys the ash to a silo. Because the airlocks are not located under the hopper, combination vacuum/pressure systems have the space advantages of dry vacuum systems.
- *Mechanical System:* Oil-fired units or other units that generate a low volume of fly ash may use manual or systematic approaches to remove fly ash (e.g., scraping the sides of the boilers with sprayers or shovels, then collecting and removing the fly ash to an intermediate storage destination or disposal).

The following identifies the number of units (and plants) in the steam electric industry operating each of the different technologies available to eliminate the discharge of fly ash transport water:

- Wet vacuum pneumatic system—51 units (22 plants);
- Dry vacuum pneumatic system—485 units (220 plants);
- Pressure system—188 units (91 plants);
- Combined vacuum/pressure system—223 units (102 plants);
- Mechanical system—16 units (13 plants); and
- Other dry systems—5 units (3 plants).

3. Bottom Ash Transport Water

Bottom ash (at times also referred to as boiler slag) is produced as fuel is burned in a boiler and collected in hoppers or other types of collection equipment directly below the boiler. Generally, boilers are sloped inward, with an opening at the bottom to allow the bottom ash to feed by gravity into collection hoppers. The hoppers contain water to quench the hot ash. Once the hoppers are full, gates at the bottom of the hoppers open, releasing the bottom ash and quench water to a conveying line, where the ash is diluted with water to approximately 20 percent solids (by weight) and pumped to a surface impoundment or a dewatering bin for solids removal. Conveying bottom ash in a water slurry is called wet sluicing. EPA identified 870 units (345 plants) that wet sluice at least a portion of their bottom ash. For further information, see Section 4.3.2 of the Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD)—EPA 821–R–13–002.

Many coal and oil-fired power plants design their bottom ash handling systems to reduce or eliminate the discharge of bottom ash handling transport water. Available technologies include:

- *Mechanical Drag System:* In these systems, the ash collection hopper is replaced with a transition chute that routes the bottom ash to a water-filled trough. In the trough, a drag chain continuously moves the ash to an incline where it is dewatered and then conveyed to a nearby ash collection area. Excess quench water collected in the dewatering system is recycled to the quench water bath.

Although mechanical drag systems require little space under the boiler they may not be suitable for all boiler configurations.

In the steam electric industry, 99 coal-fired units use mechanical drag systems for bottom ash handling. Operators have announced plans to retrofit mechanical drag systems on additional units by 2020. EPA estimates that these announced retrofits include approximately 10–30 generating units. (Note: the precise value has been withheld to prevent disclosing CBI.)

- *Remote Mechanical Drag System:* These systems collect bottom ash in water-filled hoppers and wet sluice the ash to a mechanical drag system located away from the boilers. Sluice water collected from the dewatered bottom ash is collected and reused in the bottom ash handling system. Plants can use remote mechanical drag systems to convert existing bottom ash handling systems with limited space or other configuration limitations. One U.S. plant has installed and is currently operating a remote mechanical drag system to handle bottom ash. At least one additional plant is currently installing a remote mechanical drag systems to handle bottom ash. Additionally, a large U.S. power company has been evaluating installing remote mechanical drag systems for several of its plants.
- *Dry Vacuum or Pressure System:* These systems transport bottom ash from the boiler to a dry hopper without using any water. The system percolates air through the ash to cool it and combust unburned carbon. Cooled ash then drops to a crusher and is conveyed via vacuum or pressure to an intermediate storage destination.
- *Complete Recycle System:* Complete recycle systems transport bottom ash using the same processes as wet sluicing systems. Plants can install complete recycle on existing wet sluicing units. Instead of transporting it to an impoundment, the ash is sluiced to dewatering bins, where it is dewatered and moved to storage. The transport (sluice) water is treated to remove solids in a settling tank and is recycled to the bottom ash collection system. Prior to reusing the treated transport water, plants may add treatment chemicals to the water to adjust pH and prevent equipment corrosion.
- *Vibratory Belt System:* Bottom ash deposits on a vibratory conveyor trough, where the plant cools the ash by air and ultimately moves it through the

conveyor deck to an intermediate storage destination.

• *Mechanical System:* Oil-fired units or other units that generate a low volume of bottom ash, may use manual or systematic approaches to removing ash that accumulates in the boiler (e.g., scraping the sides of the boilers with sprayers or shovels, then collecting and removing the bottom ash to an intermediate storage destination or disposal).

The following identifies the number of units (and plants) in the steam electric industry operating each of the different technology options available to eliminate or minimize the amount of bottom ash transport water:

• Mechanical drag system—99 units (74 plants);
• Remote mechanical drag system—at least 2 units (2 plants) installing systems since 2009;
• Dry vacuum system—111 units (68 plants);
• Dry pressure system—13 units (11 plants);
• Complete recycle systems—at least 20 plants; and
• Mechanical systems—38 units (19 plants).

4. Combustion Residuals Leachate From Landfills and Surface Impoundments

Plants often treat combustion residual landfill leachate with some of the same technologies used to treat FGD wastewater as described in Section VI.C.1. EPA identified 102 coal-fired power plants that generate and discharge leachate. Based on the responses to the industry survey, 29 of these plants treat the leachate prior to discharge using surface impoundments, constructed wetlands, or biological treatment. In some cases, plants co-treat the leachate with FGD wastewaters and, in some cases, treat the leachate independently.

Based on information from the industry survey and site visits, surface impoundments are the most common type of system used to treat combustion residual leachate from landfills and impoundments. Constructed wetlands are the next most commonly used treatment system. The anoxic/anaerobic biological treatment system used as the basis for FGD wastewater effluent limits in this proposed rule is also being used by one plant to treat leachate, with the leachate mixing with FGD wastewater immediately prior to the bioreactor stage.

Some plants mix the leachate with fly ash prior to disposing the ash in a landfill to control fugitive dust emissions and to improve the handling characteristics of the dry fly ash. Leachate is also used at some plants for dust control around ash loading areas and landfills. Many plants will collect the leachate from a surface impoundment and pump it directly back to the impoundment from which it originated.

Physical/chemical treatment systems are capable of achieving low effluent concentrations of various metals and are effective at removing many of the pollutants of concern present in leachate discharges to surface waters. The pollutants of concern in leachate have also been identified as pollutants of concern for FGD wastewater, fly ash transport wastewater, bottom ash transport water, and other combustion residuals. This is to be expected since the leachate itself comes from landfills and surface impoundments containing the combustion residuals and those wastes are the source for the pollutants entrained in the leachate. Given the similarities present among the different types of wastewaters associated with combustion residuals, combustion residual leachate will be similarly amenable to chemical precipitation treatment. The treatability of pollutants such as arsenic and mercury using chemical precipitation technology is also demonstrated by technical information compiled for ELGs promulgated for other industry sectors. See, e.g., the TDDs supporting the ELGs for the Landfills point source category (EPA–821–R–99–019) and the ELGs for the Metal Products and Machinery point source category (EPA–821–B–03–001).

5. Gasification Wastewater

The treatment technologies in use at steam electric power plants for gasification wastewater include:

• *Vapor-Compression Evaporation System:* This type of system is identical to the vapor-compression evaporation system described for FGD wastewater. It uses a falling-film evaporator (or brine concentrator) to produce a concentrated wastewater stream and a distillate stream. The concentrated wastewater stream may be further processed in a crystallizer or spray dryer, which evaporates the remaining water to generate a solid waste product and potentially a condensate stream. Facilities may reuse the distillate and condensate streams within the plant or discharge them to surface waters.

• *Cyanide Destruction System:* This system adds sodium hypochlorite (i.e., bleach) to the wastewater in mixing tanks to destroy the cyanide. The cyanide system treats the condensate and distillate streams from both the brine concentrator and crystallizer just prior to discharge.

EPA is aware of two plants that currently operate integrated gasification combined cycle (IGCC) units in the United States, and a third plant is scheduled to begin operating an IGCC unit this year. All three of these plants currently treat or plan to treat the IGCC wastewaters with vapor-compression evaporation systems. The IGCC plant scheduled to begin operating this year is installing both a vapor-compression evaporation system and a cyanide destruction system to treat the gasification wastewater.

6. Flue Gas Mercury Control (FGMC) Wastewater

FGMC wastewater originates from activated carbon injection systems. The system can be configured either upstream or downstream of the primary particulate collection system. EPA identified 73 plants with current or planned activated carbon injection systems. Of these, 58 plants operate upstream injection systems while the remaining 15 plants inject the carbon downstream.

In cases where the injection occurs upstream of the primary particulate collection system, plants collect and handle the mercury-containing carbon with the fly ash. In cases where the injection occurs downstream of the primary particulate collection system, plants collect the mercury-containing carbon in a secondary particulate control system (e.g., a fabric filter). As with fly ash systems, plants collect the mercury-containing carbon in hoppers located underneath the equipment. From the collection hoppers, plants either transfer the mercury-containing carbon as dry ash to silos for temporary storage (67 plants; 92 percent) or transport (sluice) it with water to an ash impoundment (6 plants; 8 percent). Water transport can result in a wastewater discharge, typically an overflow from the impoundment. However, five of the six plants that use water to transport the FGMC waste to a surface impoundment do not discharge any FGMC wastewater and the remaining plant has the capability to handle the FGMC waste using a dry system but sometimes uses a wet system instead.

Coal-fired power plants can minimize or eliminate the discharge of FGMC particulate handling transport water by using the same solids handling technologies that are available for fly ash. These technologies include:

• *Wet Vacuum Pneumatic System:* These systems use water-powered hydraulic vacuums to withdraw dry FGMC waste from the hoppers, similar to wet sluicing systems. Instead of

sluicing the FGMC waste to a surface impoundment, these systems capture the FGMC waste in a filter—receiver (bag filter with a receiving tank) and then deposit it in a silo.

- *Dry Vacuum Pneumatic System:* These systems use a mechanical exhauster to move air, below atmospheric pressure, to pull the FGMC waste from the hoppers and convey it directly to a silo. The collected FGMC waste empties from the hoppers into the conveying system via a material handling valve.
- *Pressure System:* These systems use air produced by a positive displacement blower to convey FGMC waste directly from the hopper to a silo.
- *Combined Vacuum/Pressure System:* These systems first utilize a dry vacuum system to pull FGMC waste from the hoppers to a transfer station, and then use a positive displacement blower to convey it to a silo.

7. Metal Cleaning Wastes

As described in Section VI.B.6, metal cleaning wastes are generated from cleaning any metal process equipment. Because there are many different processes at plants that use metal equipment, there are a variety of metal cleaning wastes that are generated. The treatment methods used for each of the different types of metal cleaning wastes vary to some degree depending on the specific cleaning operations.

Based on information from the industry survey, surface impoundments and chemical precipitation systems are two of the most common types of systems used to treat metal cleaning wastes. Other types of treatment systems include constructed wetlands, filtration, reverse osmosis, clarification, oil/water separation, and brine concentrators.

In addition to the treatment systems used to control the discharges of metal cleaning wastes, some plants also employ other handling approaches to control or eliminate the discharge of metal cleaning wastes. For example, some plants immediately recycle the metal cleaning wastes back to other plant operations, while other plants evaporate the metal cleaning wastes in the boiler to evaporate the wastewater and eliminate the discharge. Other handling operations reported in the industry survey include offsite treatment, hazardous waste disposal, third-party disposal, mixing with fly ash and landfilling, and deep well injection.

Physical/chemical treatment systems are capable of reducing the concentration of pollutants, including metals, in the wastewater.

## VII. Selection of Regulated Pollutants

### *A. Identifying the Pollutants of Concern*

The following paragraphs discuss the pollutants of concern identified for each of the wastestreams considered for regulation in this proposal. For the purpose of this rulemaking, pollutants of concern are those pollutants that have been quantified in a wastestream at sufficient frequency at treatable levels (i.e., concentrations). EPA used the following sources of wastewater characterization data to identify pollutants of concern in wastewater from steam electric power plants: EPA's field sampling program, industry-supplied data including data provided in responses to the industry survey, and various literature sources. EPA relied primarily on its field sampling program data because the data were collected using consistent methods and analytical techniques for a broad range of pollutants. Therefore, where EPA had data from its field sampling program, it preferentially used that data. Where EPA did not collect field sampling data for a wastestream and industry-supplied data was available, EPA used that data. In the absence of either EPA field sampling data or industry-supplied data, EPA used literature data.

After reviewing the available sources of data for each of the wastestreams addressed by this rulemaking, EPA first combined the pollutant data to create consolidated datasets representing the concentrations of pollutants present in each wastestream prior to treatment. EPA then eliminated all pollutants that were not detected in any wastewater samples—any pollutants falling into this category are not considered pollutants of concern. Finally, for the remaining pollutants for each wastestream, EPA then identified each pollutant that was detected at a concentration greater than or equal to ten times the baseline value (see Section 6 of the TDD) in at least 10 percent of all untreated process wastewater samples.[13]

EPA identified the following 34 pollutants of concern for FGD wastewater using EPA field sampling data: one conventional pollutant (TSS);[14] 13 toxic pollutants, including arsenic, cyanide, mercury, and selenium; 12 nonconventional metals; and 8 other nonconventional pollutants (e.g., ammonia, nitrate/nitrite, and total phosphorus).

EPA identified the following 24 pollutants of concern for fly ash transport water using EPA field sampling data: one conventional pollutant (TSS);[15] 9 toxic pollutants (metals including arsenic, lead, mercury, and selenium); 11 nonconventional pollutant metals; and 3 other nonconventional pollutants (i.e., TDS, chloride, and nitrate/nitrite).

EPA was unable to obtain readily available data for untreated bottom ash transport water for use in identifying the pollutants of concern using the methodology described above. However, because the pollutants found in bottom ash are constituents that are present in the coal (or petroleum coke or oil), as is the case for fly ash, EPA concluded that the pollutants of concern for bottom ash transport water are identical to the pollutants of concern identified for fly ash transport water.

EPA was also unable to obtain readily available data for identifying the pollutants of concern in FGMC wastewater. Nevertheless, based on process knowledge and engineering judgment, EPA concluded that the pollutants of concern for FGMC wastewater are likely to be identical to the pollutants of concern identified for fly ash transport water. This is due to the fact that, when activated carbon is injected into the flue gases, the carbon intermixes with the fly ash particles, and then the commingled mixture of activated carbon (which adsorbs mercury and other pollutants from the flue gases) and fly ash particles is captured together and transferred to the FGMC wastewater.

EPA evaluated the pollutants of concern for combustion residual leachate using industry sampling data for untreated leachate submitted under Part G of the industry survey. EPA evaluated the landfill leachate separately from the surface impoundment leachate. The pollutants of concern for landfill leachate include the following: one conventional pollutant (TSS);[16] 3 toxic pollutants

[13] This is consistent with the process EPA used to identify pollutants of concern for many categories. EPA takes this approach to ensure the pollutants are present in treatable levels.

[14] EPA did not analyze its field sampling data for oil and grease. Rather, since the existing steam electric ELG currently contains BPT limitations applicable to FGD wastewater for oil and grease, EPA already has data from the existing rulemaking demonstrating oil and grease is also a pollutant of concern in FGD wastewater.

[15] EPA did not analyze its field sampling data for oil and grease. Rather, since the existing steam electric ELG currently contains BPT limitations applicable to fly ash transport wastewater for oil and grease, EPA already has data from the existing rulemaking demonstrating oil and grease is also a pollutant of concern in fly ash wastewater.

[16] The landfill leachate samples were not analyzed for oil and grease. Rather, since the existing steam electric ELG currently contains BPT limitations applicable to combustion residual leachate for oil and grease, EPA already has data from the existing rulemaking demonstrating oil and

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(arsenic, mercury, and selenium); 9 nonconventional pollutant metals; and 3 other nonconventional pollutants (i.e., chloride, sulfate and TDS). The pollutants of concern for impoundment leachate include:[17] 2 toxic pollutants (i.e., arsenic and mercury), 7 nonconventional pollutant metals, and 3 other nonconventional pollutants (i.e., chloride, sulfate, and TDS).

EPA identified 19 pollutants of concern for gasification wastewater using EPA field sampling data, including: 1 conventional pollutant (BOD); 7 toxic pollutants (including arsenic, cyanide, mercury, and selenium); 5 nonconventional pollutant metals; and 6 other nonconventional pollutants.

As part of the 1974 rulemaking, EPA collected characterization data associated with chemical and nonchemical metal cleaning wastes. Based on the data collected during that rulemaking, EPA determined that TSS, oil and grease, copper, and iron were pollutants of concern for this wastestream warranting regulation and established BPT limitations for these four pollutants in discharges of metal cleaning wastes, including both nonchemical and chemical metal cleaning wastes. (EPA has also established BAT, NSPS, PSES, and PSNS for chemical metal cleaning wastes.) For additional information regarding the pollutants that may be present in nonchemical metal cleaning wastes, see the 1974 *Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category.* Based on the information developed for the previous rulemakings for the steam electric power generating ELGs and the data from the industry survey, EPA identified 4 pollutants of concern for nonchemical metal cleaning wastes, including: 2 conventional pollutants (TSS and oil and grease); 1 toxic pollutant (copper); and 1 nonconventional pollutant (iron).

See Section 6 of the Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD)—EPA 821–R–13–002 for more detailed information regarding pollutants of concern.

*B. Selection of Pollutants for Regulation Under BAT/NSPS*

The pollutants of concern identified for each wastestream represents those pollutants that are present at treatable concentrations in a significant percentage of untreated wastewater samples from that wastestream. Effluent limits and monitoring for all pollutants of concern is not necessary to ensure that the pollutants are adequately controlled because many of the pollutants originate from similar sources, have similar treatabilities, and are removed by similar mechanisms. Because of this, it may be sufficient to establish effluent limits for one pollutant as a surrogate or indicator pollutant that ensures the removal of other pollutants of concern. In addition, establishing effluent limits may not be appropriate for certain pollutants of concern when the technology used as the basis for the effluent limits is not reliably effective at removing the pollutant(s).

From the list of pollutants of concern identified for each wastestream, EPA selected a subset of pollutants for establishing numeric effluent limitations. EPA considered the following factors in selecting regulated pollutants from the list of pollutants of concern:

- The pollutant was detected in the untreated wastewater at treatable levels in a significant number of samples.
- The pollutant is not used as a treatment chemical in the treatment technology that serves as a basis for the proposed regulatory option. EPA eliminated pollutants associated with treatment system additives because regulating these pollutants could interfere with efforts to optimize treatment system operation.
- The pollutant is effectively treated by the treatment technology that serves as the basis for the proposed regulatory option. EPA excluded all pollutants for which the treatment technology was ineffective (e.g., pollutant concentrations remained approximately unchanged or increased across the treatment system).
- The pollutant is not adequately controlled through the regulation of another pollutant.

Because the criteria for identifying regulated pollutants from the list of pollutants of concern depends on the treatment technology that serves as the basis for a proposed regulatory option, EPA may regulate a different subset of pollutants for a single wastestream under different regulatory options.

For the proposed options for this rulemaking (described below in Section VIII), EPA identified six pollutants for potential regulation for FGD wastewater: oil and grease, TSS, arsenic, mercury, nitrate/nitrite, and selenium. For leachate, EPA identified four potential pollutants for regulation: oil and grease, TSS, arsenic and mercury.

For fly ash discharges, bottom ash, and FGMC wastewater, under some proposed options, EPA is proposing to establish zero discharge limitations, which in effect directly control all pollutants of concern. For other proposed options that would not require zero pollutant discharge, EPA identified two potential pollutants for regulation: oil and grease and TSS for nonchemical metal cleaning wastes, EPA identified four pollutants for potential regulation (TSS, oil and grease, copper, and iron). EPA identified four pollutants for regulation for gasification wastewater: arsenic, mercury, selenium, and TDS.

See Section 6.7 of the Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD)—EPA 821–R–13–002 for more information about the pollutants of concern and EPA's rationale for selecting the pollutants proposed for regulation.

*C. Methodology for the POTW Pass Through Analysis (PSES/PSNS)*

Section 307(b) and (c) of the CWA requires EPA to promulgate pretreatment standards for pollutants that are not susceptible to treatment by POTWs or which would interfere with the operation of POTWs. EPA looks at a number of factors in selecting the technology basis for pretreatment standards for existing and new sources. These factors are generally the same as those considered in establishing BAT and NSPS, respectively. However, unlike direct dischargers whose wastewater will receive no further treatment once it leaves the facility, indirect dischargers send their wastewater to POTWs for further treatment. As such, EPA must also determine that a pollutant is not susceptible to treatment at a POTW or would interfere with POTW operations.

Before establishing PSES/PSNS for a pollutant, EPA examines whether the pollutant "passes through" a POTW to waters of the U.S. or interferes with the POTW operation or sludge disposal practices. In determining whether a pollutant would pass through POTWs, EPA generally compares the percentage of a pollutant removed by well-operated POTWs performing secondary treatment

grease is also a pollutant of concern in combustion residual leachate.

[17] The surface impoundment leachate samples were not analyzed for oil and grease. Rather, since the existing steam electric ELG currently contains BPT limitations applicable to combustion residual leachate for oil and grease, EPA already has data from the existing rulemaking demonstrating oil and grease is also a pollutant of concern in combustion residual leachate.

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to the percentage removed by BAT/NSPS treatment systems. A pollutant is determined to pass through POTWs when the median percentage removed nationwide by well-operated POTWs is less than the median percentage removed by direct dischargers complying with BAT/NSPS effluent limitations and standards. Pretreatment standards are established for those pollutants regulated under BAT/NSPS that pass through POTWs to waters of the U.S. or interfere with POTW operations or sludge disposal practices. This approach to the definition of pass-through satisfies two competing objectives set by Congress: (1) That standards for indirect dischargers be equivalent to standards for direct dischargers, and (2) that the treatment capability and performance of POTWs be recognized and taken into account in regulating the discharge of pollutants from indirect dischargers.

For this proposed rule, EPA conducted a pass through analysis for the technology basis for each wastestream for each regulatory option presented below in Section VII.C. For those wastestreams and regulatory options for which EPA is proposing zero discharge of pollutants, EPA set the percentage removed by the technology basis at 100 percent. EPA did not conduct its traditional pass-through analysis for these wastestreams (e.g., fly ash transport water, bottom ash transport water, and flue gas mercury control wastewater) because limitations for these wastestreams for direct dischargers would consist of no discharge of process wastewater pollutants to waters of the U.S., and therefore, all pollutants would "pass through" the POTW for these wastestreams.

During the 1976 development of pretreatment standards for chemical metal cleaning wastes, EPA selected pollutants for regulation based on two criteria:

- The pollutant has the potential to harm the POTW (e.g., impair the activity of the biological treatment system); or
- The pollutant has the potential to harm the receiving water (i.e., if the pollutant is not removed or is removed inadequately by the POTW).

Using these criteria, the Agency determined it was appropriate to establish pretreatment standards for the discharge of copper in chemical metal cleaning wastes. For this rulemaking, EPA believes that, as is the case for copper in chemical metal cleaning wastes, the copper present in nonchemical metal cleaning wastes would pass through the POTW.

For FGD wastewater, leachate, and gasification wastewater, EPA determined the percentage removed for the pollutants by the technology basis using the same data sources used to determine the long-term averages for each set of limitations (see Section 13 of the TDD).[18] As it has done for other rulemakings, EPA determined the percentage removed by well-operated POTWs performing secondary treatment from one of two data sources:

- Fate of Priority Pollutants in Publicly Owned Treatment Works, September 1982, EPA 440/1–82/303 (50 POTW Study); and
- National Risk Management Research Laboratory (NRMRL) Treatability Database, Version 5.0, February 2004 (formerly called the Risk Reduction Engineering Laboratory (RREL) database).

The 50 POTW study presents data on the performance of 50 POTWs achieving secondary treatment in removing toxic pollutants. When data for a pollutant were available from the 50 POTW Study, EPA used that data. When data for pollutants were not available from the 50 POTW Study, EPA used NRMRL data. The NRMRL treatability database provides information on removals obtained by various treatment technologies for a variety of wastewater sources. Therefore, where EPA used data from the NRMRL treatability database, it used only data from the treatment of domestic and industrial wastewater using technologies representative of secondary treatment. For a more detailed discussion of how EPA performed its removal analysis, see Section 11 of the TDD.

With a few exceptions, EPA performs a POTW pass-through analysis for pollutants selected for regulation for BAT/NSPS for each wastestream of concern and for each regulatory option. The exception is for conventional pollutants such as $BOD_5$, TSS, and oil and grease. POTWs are designed to treat these conventional pollutants; therefore, they are not considered to pass through.

Section VIII below summarizes the results of the pass through analysis. All of the pollutants proposed for regulation under BAT/NSPS (except for conventional pollutants and iron found in nonchemical metal cleaning wastes) were found to pass through and, therefore, were selected for regulation under PSES/PSNS.

[18] For FGD wastewater and leachate, this discussion applies to those regulatory options that would provide additional control for discharges of toxics like arsenic, mercury and selenium.

## VIII. Proposed Regulation

### *A. Regulatory Options*

#### 1. BPT/BCT

EPA is not proposing to revise the BPT effluent guidelines or establish BCT effluent guidelines in this notice because the same wastestreams would be controlled at the proposed BAT/BADCT (NSPS) level of control. EPA is proposing to remove FGD wastewater, FGMC wastewater, gasification wastewater, and leachate from the definition of low-volume wastes. As a result, EPA is making a structural adjustment to the text of the regulation at 40 CFR part 423 to add paragraphs that list these four wastestreams by name, along with their applicable effluent limitations. The reformatted regulatory text for these four wastestreams includes BPT effluent limits, which are the same as the current BPT effluent limits for low volume wastes.

#### 2. Description of the BAT/NSPS/PSES/PSNS Options

EPA is proposing to revise or establish BAT, BADCT (NSPS), PSES, and PSNS that may apply to discharges of seven wastestreams: FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate, nonchemical metal cleaning wastes, and wastewater from FGMC systems and gasification systems. In Section VI of this preamble and in the TDD, EPA describes the treatment technologies and operational practices that it reviewed during the development of this proposed rule. From these, EPA identified a subset of technologies (treatment processes and operational practices) that were most promising as candidate BAT/BADCT options. In this proposal, EPA is presenting eight main regulatory options (i.e., Option 1, Option 3a, Option 2, Option 3b, Option 3, Option 4a, Option 4, and Option 5) that represent different levels of pollutant removal associated with different wastewater streams (i.e., each succeeding option from Option 1 to Option 5 would achieve more reduction in discharges of pollutants to waters of the U.S). Table VIII–1 summarizes the eight main regulatory options, which are described in the paragraphs below.

As discussed further below, EPA is also proposing to add provisions to the ELGs that would prevent facilities from circumventing applicable ELGs. The proposed provisions would clarify the acceptable conditions for discharge of reused process wastewater and establish effluent monitoring requirements.

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EPA is considering establishing BMPs that would apply to surface impoundments (i.e., ponds) that receive, store, dispose of, or are otherwise used to manage coal combustion residuals including FGD wastes, fly ash, bottom ash (which includes boiler slag), leachate, and other residuals associated with the combustion of coal to prevent uncontrolled discharges from these impoundments as described below in the paragraph titled, "BMPs for CCR Surface Impoundments."

As part of its consideration of technological availability and economic achievability for all regulatory options, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at facilities to meet the requirements of the rule. As described further below, EPA proposes that certain limitations and standards being proposed today for existing sources would not apply until July 1, 2017 (approximately three years from the effective date of this rule).

EPA is also considering establishing, as part of the BAT for existing sources, a voluntary incentive program that would provide more time for plants to implement the proposed BAT requirements if they adopt additional process changes and controls that would provide significant environmental protections beyond those achieved by the preferred options in this proposed rule. As described further below, power plants would be granted two additional years (beyond the time described above in the preceding paragraph) if they also dewater, close and cap all CCR surface impoundments at the facility (except combustion residual leachate impoundments), including those surface impoundments located on non-adjoining property that receive CCRs from the facility. A power plant participating in the voluntary incentive program could continue to operate surface impoundments for which combustion residual leachate was the only type of CCR solids or wastewater contained in the impoundment. Power plants would be granted five additional years (beyond the time described above in the preceding paragraph) if they eliminate discharges of all process wastewater to surface waters, with the exception of cooling water discharges.

TABLE VIII–1—STEAM ELECTRIC MAIN REGULATORY OPTIONS

| Wastestreams | Technology basis for the main BAT/NSPS/PSES/PSNS regulatory options | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 1 | 3a | 2 | 3b | 3 | 4a | 4 | 5 |
| FGD Wastewater .... | Chemical Precipitation. | BPJ Determination. | Chemical Precipitation + Biological Treatment. | Chemical Precipitation + Biological Treatment for units at a facility with a total wet-scrubbed capacity of 2,000 MW and more; BPJ determination for <2,000 MW. | Chemical Precipitation + Biological Treatment. | Chemical Precipitation + Biological Treatment. | Chemical Precipitation + Biological Treatment. | Chemical Precipitation + Evaporation |
| Fly Ash Transport Water. | Impoundment (Equal to BPT). | Dry handling ... | Impoundment (Equal to BPT). | Dry handling ... | Dry handling ... | Dry handling ... | Dry handling ... | Dry handling |
| Bottom Ash Transport Water. | Impoundment (Equal to BPT). | Impoundment (Equal to BPT). | Impoundment (Equal to BPT). | Impoundment (Equal to BPT). | Impoundment (Equal to BPT). | Dry handling/ Closed loop (for units >400 MW); Impoundment (Equal to BPT)(for units ≤400 MW). | Dry handling/ Closed loop. | Dry handling/ Closed loop |
| Combustion Residual Leachate. | Impoundment (Equal to BPT). | Impoundment (Equal to BPT). | Impoundment (Equal to BPT). | Impoundment (Equal to BPT). | Impoundment (Equal to BPT). | Impoundment (Equal to BPT). | Chemical Precipitation. | Chemical Precipitation |
| FGMC Wastewater | Impoundment (Equal to BPT). | Dry handling ... | Impoundment (Equal to BPT). | Dry handling ... | Dry handling ... | Dry handling ... | Dry handling ... | Dry handling |
| Gasification Wastewater. | Evaporation ..... | Evaporation ..... | Evaporation ..... | Evaporation ..... | Evaporation ..... | Evaporation ..... | Evaporation ..... | Evaporation |
| Nonchemical Metal Cleaning Wastes [19]. | Chemical Precipitation. | Chemical Precipitation. | Chemical Precipitation. | Chemical Precipitation. | Chemical Precipitation. | Chemical Precipitation. | Chemical Precipitation. | Chemical Precipitation |

*FGD Wastewater.* Addressing the variety of pollutants present in FGD wastewater typically requires several stages of treatment to remove the suspended solids, particulate and dissolved metals, and other pollutants present. Historically, power plants have relied on surface impoundments to treat FGD wastewater because NPDES permits generally focused on controlling suspended solids for this wastestream. Surface impoundments are the technology basis for the current BPT effluent limits (last revised in 1982) for steam electric power plants. In recent years, physical/chemical treatment systems and other more advanced systems have become more widely used as effluent limits for metals and other pollutants have been included in permits, in nearly all cases driven by the need to utilize such technologies to meet water quality-based effluent limits (WQBELs) established to meet applicable water quality standards in

[19] As described in Section VIII, EPA is proposing to exempt from new copper and iron BAT limitations any existing discharges of nonchemical metal cleaning wastes that are currently authorized without iron and copper limits.

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the receiving waters. At present, a number of steam electric plants either use chemical precipitation or chemical precipitation and biological treatment to control discharges of FGD wastes. However, surface impoundments continue to be the predominant technology used to treat FGD wastewater, with 54 percent of plants that discharge FGD wastewater relying on this technology alone (i.e., not including the plants that use surface impoundments as pretreatment for more advanced treatment). In addition, it is common for plants to commingle the surface impoundment FGD effluent with wastestreams of significantly higher flows (e.g., ash transport water and cooling water) because the higher-flow wastestreams dilute the FGD wastewater so that the resulting pollutant concentrations in the combined wastestream do not exceed the applicable water quality-based effluent limitations.

Surface impoundments use gravity to remove solid particles (i.e., suspended solids) from the wastewater. Metals in FGD wastewater are present in both soluble (i.e., dissolved) and particulate form. Some metals, such as arsenic, are often present mostly in particulate form; these usually can be removed to a substantial degree by a well-operated settling process that has a sufficiently long residence time. However, other pollutants, such as selenium, boron, and magnesium, are present mostly in soluble form and are not effectively and reliably removed by wastewater surface impoundments. For metals present in both soluble and particulate forms (such as mercury), surface impoundments will not effectively remove the dissolved fraction. Furthermore, the conditions present in some surface impoundments can create chemical conditions (e.g., low pH) that convert particulate forms of metals to soluble forms, which would not be removed by the gravity settling process in the surface impoundment. Additionally, EPRI (a technical research organization funded by the electric power industry) has reported that adding FGD wastewater to surface impoundments used to treat ash transport water (i.e., ash ponds) may reduce the settling efficiency in the impoundments due to gypsum particle dissolution, thus increasing the effluent TSS concentrations. EPRI has also reported that the FGD wastewater includes high loadings of volatile metals, which can increase the solubility of metals in surface impoundments, thereby leading to increased levels of dissolved metals and resulting in higher concentrations of metals in the discharge from surface impoundments.

During the summer, some surface impoundments become thermally stratified. When this occurs, the top layer of the impoundment is warmer and contains higher levels of dissolved oxygen, whereas the bottom layer of the impoundment is colder and can have significantly lower levels of oxygen and may develop anoxic conditions. Typically, during fall, as the air temperature decreases, the upper layer of the impoundment becomes cooler and denser, thereby sinking and causing the entire volume of the impoundment to circulate. Solids that have collected at the bottom of the impoundment may become resuspended due to such mixing, increasing the concentrations of pollutants discharged during the turnover period. Seasonal turnover effects largely depend upon the size and configuration of the surface impoundment. Smaller, and especially shallow, surface impoundments likely do not experience turnover because they do not have physical characteristics that promote thermal stratification. However, some surface impoundments are large (e.g., greater than 300 acres) and deep (e.g., greater than 10 meters deep) and likely experience some degree of turnover.

Technologies more advanced than surface impoundments exist and that are more effective at removing both soluble (i.e., dissolved) and particulate forms of metals, as well as other pollutants such as nitrogen compounds and TDS. Because many of the pollutants of concern for FGD wastewater are present in dissolved form and would not be removed by surface impoundments, and because of the relatively large mass loads of these pollutants (e.g., selenium, dissolved mercury) discharged by the FGD wastestream, EPA explored other technologies that would be more effective at removing these pollutants of concern and is co-proposing three options that would include such technologies. However, for reasons discussed in Section VII.A.3, EPA is also co-proposing options under which some or all facilities would continue, for the purposes of the ELGs, to be subject to the BPT requirements based on surface impoundments for treatment of FGD wastewater. Under these options, BAT would be left to a site-specific determination. For the reasons discussed above and in Section VIII.A.3, EPA also does not believe that surface impoundments represent best available demonstrated control technology for controlling pollutants in FGD wastewater. Therefore, none of the regulatory options for NSPS presented in this proposal are based on the performance of surface impoundments for FGD wastewater.

The technology basis for the effluent limitations and standards for FGD wastewater in Option 1 is physical/chemical treatment consisting of the following: Chemical precipitation/coprecipitation (employing the combination of hydroxide precipitation, iron coprecipitation, and sulfide precipitation). Option 1 also incorporates the use of flow minimization for plants with high FGD discharge flow rates (i.e., greater than 1,000 gpm) and FGD system metallurgy and operating practices that can accommodate an increase in chlorides (e.g., scrubber systems constructed of non-metallic materials or corrosion-resistant metal alloys, or systems operating with absorber chloride concentrations substantially below the design chloride limit). The flow minimization at these plants would be achieved by either reducing the FGD purge rate or recycling a portion of their FGD wastewater.

Physical/chemical treatment (i.e., chemical precipitation) is used to remove metals and other pollutants from wastewater. Chemicals are added to the wastewater in a series of reaction tanks to convert soluble metals to insoluble metal hydroxide or metal sulfide compounds, which precipitate from solution and are removed along with other suspended solids. An alkali, such as hydrated lime, is typically added to adjust the pH of the wastewater to the point where metals precipitate out as metal hydroxides (typically referred to as hydroxide precipitation). Chemicals such as ferric chloride are often added to the system to increase the removal of certain metals through iron coprecipitation. The ferric chloride also acts as a coagulant, forming a dense floc that enhances settling of the metal precipitate in the downstream clarification stage. Coagulants and flocculants are often added to facilitate the settling and removal of the newly formed solids. Plants trying to increase removals of mercury and other metals will also include sulfide addition (e.g., organosulfide) as part of the process. Adding sulfide chemicals in addition to hydroxide precipitation provides even greater reductions of heavy metals due to the very low solubility of metal sulfide compounds, relative to metal hydroxides. Sulfide precipitation is widely used in Europe and multiple locations in the United States have installed this technology. Forty U.S. power plants (34 percent of plants

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discharging FGD wastewater) include physical/chemical treatment as part of the FGD wastewater treatment system; more than half of these plants (28 percent of plants discharging FGD wastewater) use both hydroxide and sulfide precipitation in the process.

The technology basis for the effluent limitations and standards for FGD wastewater in Options 2, 3b (for units located at facilities with a total wet-scrubbed capacity of 2,000 MW or more)[20], 3, 4a, and 4 is chemical precipitation/coprecipitation (the same technology basis under Option 1) used in combination with anoxic/anaerobic biological treatment designed to optimize removal of selenium. As is the case for Option 1, these BAT options also incorporate the use of flow minimization for plants with high FGD discharge flow rates (i.e., greater than 1,000 gpm) and FGD system metallurgy and operating practices that can accommodate an increase in chlorides. The flow minimization at these plants would be achieved by either reducing the FGD purge rate or recycling a portion of their FGD wastewater.

Physical/chemical treatment systems are capable of achieving low effluent concentrations of various metals and the sulfide addition is particularly important for removing mercury; however, this technology is not effective at removing selenium, nitrogen compounds, and certain metals that contribute to high concentrations of TDS in FGD wastewater (e.g., bromides, boron). Six power plants in the U.S. are operating FGD treatment systems that include a biological treatment stage designed to substantially reduce nitrogen compounds and selenium.[21] Other industries have also used this technology to remove selenium and other pollutants. These systems use anoxic/anaerobic bioreactors optimized to remove selenium from the wastewater. The bioreactor alters the form of selenium, reducing selenate and selenite to elemental selenium, which is then captured by the biomass and retained in treatment system residuals. The conditions in the bioreactor are also conducive to forming metal sulfide complexes to facilitate additional removals of mercury, arsenic, and other metals. The information in the record for this proposed rule demonstrates that the amount of mercury and other pollutants removed by the biological treatment stage of the treatment system, above and beyond the amount of pollutants removed in the chemical precipitation treatment stage preceding the bioreactor, can be substantial. In addition, the anoxic conditions in the bioreactor remove nitrates by denitrification and, if necessary, the biological processes can be modified to include a step to nitrify and remove ammonia. Four of these six plants precede the biological treatment stage with physical/chemical treatment; thus, the entire system is designed to remove suspended solids, particulate and dissolved metals, soluble and insoluble forms of selenium, and nitrate and nitrite forms of nitrogen. The other two plants operating anoxic/anaerobic bioreactors to remove selenium precede the biological treatment stage with surface impoundments instead of chemical precipitation. While the treatment systems at these two plants would be less effective at removing metals (including many dissolved metals) than the plants utilizing chemical pretreatment, they nevertheless show the efficacy of biological treatment for removing selenium and nitrate/nitrite from FGD wastewater. Three percent of the plants discharging FGD wastewater use chemical precipitation followed by anaerobic biological treatment to treat this wastewater, which is the technology basis for Options 2, 3b (for units located at facilities with a total wet-scrubbed capacity of 2,000 MW or more), 3, 4a, and 4.

The technology basis for the effluent limitations and standards for FGD wastewater in Option 5 is chemical precipitation/coprecipitation used in combination with vapor compression evaporation. Physical/chemical treatment systems can achieve low effluent concentrations for a number of pollutants, and reduce concentrations even further when combined with biological treatment systems, as described above and in the TDD. However, these technologies have not been effective at removing substantial amounts of boron and pollutants such as sodium and bromides that contribute to high concentrations of TDS. Another FGD wastewater treatment technology that can address these more recalcitrant pollutants, as well as removing the pollutants treated by physical/chemical and biological technologies, is vapor-compression evaporation. This technology uses an evaporator to produce a concentrated wastewater stream and a reusable distillate stream. The concentrated wastewater stream is either disposed of or further processed to produce a solid by-product and additional distillate. The plant can reuse the distillate stream as makeup water. Two U.S. plants and four Italian plants are operating this technology to treat FGD wastewater from their coal-fired generating units.[22]

For Option 3a and Option 3b (for units located at facilities with a total wet-scrubbed capacity of less than 2,000 MW), EPA is proposing not to characterize a technology basis for effluent limitations and standards applicable to discharges of pollutants in FGD wastewater at this time. As illustrated above, there is a wide range of technologies currently in use for reducing pollutant discharges associated with FGD wastewater, and research continues in the development of additional technologies to treat FGD wastewater (see Section 7.1.7 of the TDD for more information on emerging technologies). The more advanced technologies (those that reduce the most pollutants) reflect recent innovations in the area of treatment of FGD wastewater. EPA expects this trend to continue and, therefore, under Option 3a and Option 3b (for units located at facilities with a total wet-scrubbed capacity of less than 2,000 MW), effluent limitations representing BAT for discharges of FGD wastewater would be determined on a site-specific BPJ basis. Under Options 3a and Option 3b (for units located at facilities with a total wet-scrubbed capacity of less than 2,000 MW), pretreatment program control authorities would need to develop local limits to address the introduction of pollutants in FGD wastewater by steam electric plants to the POTWs that cause pass through or interference, as specified in 40 CFR 403.5(c)(2).

As described below in this section of the preamble, EPA is proposing that certain limitations and standards being proposed today for existing sources would apply to discharges of FGD wastewater generated on or after the date established by the permitting authority that is as soon as possible within the next permit cycle after July 1, 2017. FGD wastewater generated prior to that date (i.e., "legacy" wastewater) from existing direct dischargers would remain subject to the existing BPT effluent limits. For indirect dischargers, EPA is proposing that PSES for FGD wastewater would apply to FGD wastewater generated after a date determined by the control authority that is as soon as possible beginning July 1,

[20] This value is calculated by summing the nameplate capacity for all of the units that are serviced by wet FGD systems.

[21] A seventh plant is scheduled to begin operating a biological treatment system for selenium removal next year. Another plant is installing a similar treatment system to remove selenium in discharges of combustion residual leachate.

[22] A third U.S. plant is currently installing a vapor-compression evaporation system to treat the FGD wastewater.

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2017. EPA considered subjecting legacy FGD wastewater to the proposed BAT and PSES requirements. However, as explained above, FGD wastewater and its associated pollutants are typically sent to surface impoundments for treatment prior to discharge. These surface impoundments often contain other plant wastewaters, such as fly ash or bottom ash transport water, coal pile runoff, and/or low volume wastes. According to data provided by the industry survey, 78 percent of surface impoundments that receive FGD wastewater also receive fly ash and/or bottom ash transport water. EPA does not have the data to demonstrate that the technologies identified above represent BAT for legacy FGD wastewater. As such, EPA is not proposing BAT requirements associated with discharges of legacy FGD wastewater generated prior to the date established by the permitting authority (for direct dischargers) or control authority (for indirect dischargers). As proposed today, discharges of legacy FGD wastewater by existing direct dischargers would remain subject to the existing BPT effluent limits; however, under some of the proposed options, EPA is also considering setting the BAT effluent limitations for legacy FGD wastewater that has not been mixed with non-legacy wastes equal to the existing BPT effluent limits. See Section XVI for additional information.

*Fly Ash Transport Water.* Under Options 1 and 2, BAT effluent limitations for fly ash transport water would be set equal to the current BPT effluent limitations, based on the technology of gravity settling in surface impoundments to remove suspended solids. The current effluent guidelines for existing sources include BPT effluent limits for the allowable levels of TSS and oil and grease in discharges of fly ash transport water. The BPT effluent limits are based on the performance of surface impoundments, which when well-designed and well-operated can effectively remove suspended solids, including pollutants such as particulate forms of certain metals when associated with the suspended solids.

Under Options 3a, 3b, 3, 4a, 4, and 5, EPA would establish "zero discharge" effluent limitations and standards for discharges of pollutants in fly ash transport water, based on the use of dry fly ash handling technologies. The dry handling technologies for fly ash are described above in Section VI of this preamble and in the TDD for the proposed rule. Although surface impoundments can be effective at removing particulate forms of certain metals and other pollutants, they are not designed for, nor are they effective at, removing other pollutants of concern such as dissolved metals and nutrients. The concentrations of pollutants that remain in the ash impoundment effluent following gravity settling, in combination with the large volumes of fly ash transport water discharged to surface waters (2.4 MGD on average per discharging plant), results in a large mass loading of pollutants of concern being discharged from surface impoundments. Furthermore, as described in Section VI, surface impoundments can be susceptible to seasonal turnover that degrades pollutant removal efficacy, and co-managing FGD and ash wastes in the same impoundments can lead to increased pollutant discharges.

Dry handling technologies are the technology basis for the current fly ash NSPS/PSNS requirements, which were promulgated in 1982. All generating units built since then have been subject to a "zero discharge" standard. Some existing units have also converted to dry handling technologies. Due to the NSPS discharge standard or economic or operational factors, approximately 66 percent of coal- and petroleum coke-fired generating units that produce fly ash currently operate dry fly ash transport systems, while another 15 percent operate both wet and dry fly ash transport systems. The remaining 19 percent operate only wet fly ash transport systems. In cases where a unit has both wet and dry handling operations, the wet handling system is typically used as a backup to the dry system. Effluent limitations and standards based on dry ash handling would completely eliminate the discharge of pollutants in fly ash transport water.

EPA considered basing one or more regulatory options for fly ash transport water on chemical precipitation treatment technology, with numeric effluent limits for discharges of the wastestream to surface waters. EPA has not identified any facilities using this treatment technology to treat fly ash transport water, although EPA has reviewed two literature sources that describe laboratory- or pilot-scale tests using the technology. Upon reviewing the discharge flow rates for fly ash transport water, however, EPA determined that the costs associated with treatment using chemical precipitation were higher than the cost of the dry handling technology upon which Options 3a, 3b, 3, 4a, 4, and 5 are based, despite being less effective at removing pollutants. Since the costs for chemical precipitation treatment are higher than the cost for converting to dry handling technologies, and chemical precipitation removes fewer pollutants, EPA did not include chemical precipitation treatment as part of the regulatory options for fly ash in this proposed rule. See DCN SE03869.

As described below in this section of the preamble, EPA is proposing that the limitations for existing sources based on Options 3a, 3b, 3, 4a, 4, or 5 would apply to discharges of fly ash transport water generated after the date established by the permitting authority that is as soon as possible within the next permit cycle after July 1, 2017. For indirect dischargers, EPA is proposing that PSES for fly ash would apply to the fly ash transport water generated after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Fly ash transport water generated by existing direct dischargers prior to that date (i.e., "legacy" wastewater) would remain subject to the existing BPT effluent limits. EPA considered subjecting legacy fly ash transport water (i.e., the fly ash transport water generated prior to the date established by the permitting authority, as described above) to the proposed BAT zero discharge requirement. As explained above, currently fly ash transport wastewater and the associated pollutants are sent to surface impoundments for treatment prior to discharge. The technology basis identified above for the proposed zero discharge requirement eliminates the generation of the fly ash wastewater but does not eliminate fly ash transport wastewater that has already been transferred to a surface impoundment. Furthermore, the technologies identified as the basis for fly ash transport water discharge requirements have not been demonstrated for the legacy fly ash transport wastewater that has already been generated. As such, EPA is not proposing BAT or PSES requirements for discharges of legacy fly ash transport water generated prior to the date established by the permitting authority or control authority. As proposed today, discharges of legacy fly ash transport water by existing direct dischargers would remain subject to the existing BPT effluent limits; however, EPA is also considering whether to set the BAT effluent limitations for legacy fly ash transport water equal to the existing BPT effluent limits. See Section XVI for additional information.

*Bottom Ash Transport Water.* Under Options 1, 3a, 2, 3b, 3, and 4a (for units less than or equal to 400 MW), effluent limitations and standards for bottom ash transport water would be set equal to the current BPT effluent limitations,

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based on the technology of gravity settling in surface impoundments to remove suspended solids. The 1982 effluent guidelines for existing sources include BPT effluent limits for the allowable levels of TSS and oil and grease in discharges of bottom ash transport water. The BPT effluent limits are based on the performance of surface impoundments, which when well-designed and well-operated can effectively remove suspended solids, including pollutants such as particulate forms of certain metals when associated with the suspended solids.

Although surface impoundments can be effective at removing particulate forms of metals and other pollutants, they are not designed for nor are they effective at removing other pollutants of concern such as dissolved metals and nutrients. The concentrations of pollutants that remain in the wastestream at the ash impoundment effluent, in combination with the large volumes of bottom ash transport water discharged to surface waters, results in a large mass loading of pollutants of concern being discharged from surface impoundments. Effluent limitations and standards based on the technologies used as the basis for Options 4a (for units more than 400 MW), 4, and 5 would completely eliminate the discharge of pollutants in bottom ash transport water.

Under Options 4a (for units more than 400 MW), 4, and 5, EPA would establish "zero discharge" effluent limitations and standards for discharges of pollutants in bottom ash transport water, based on either using bottom ash handling technologies that do not require transport water or managing a wet-sluicing bottom ash handling system so that it does not discharge bottom ash transport water or pollutants associated with the bottom ash transport water. These technologies for handling bottom ash are described above in section VI of this preamble and in the TDD for the proposed rule. About 80 percent of coal- and petroleum coke-fired units generating bottom ash operate wet bottom ash transport systems, while approximately 20 percent operate systems that eliminate the use of transport water. Most, but not all, of the wet bottom ash transport systems discharge to surface waters. In cases where a plant has both wet and dry handling operations, the wet handling system is typically used as a backup to the dry system. In the case of bottom ash handling systems, the term "dry" is typically used to refer to a process that does not use water as the transport medium to sluice the bottom ash to a CCR impoundment. In some cases, a "dry" bottom ash system may be entirely dry and avoid all use of water. Many dry bottom ash systems, however, include a water bath at the bottom of a boiler in which the bottom ash is dropped and cooled, and then the bottom ash is mechanically dragged out of the boiler along a conveyor belt and deposited in a pile adjacent to the building housing the boiler. The bottom ash conveyed out of the water bath will be damp because the ash particles retain some moisture from the water bath and small volumes of water will typically drain from the standing bottom ash pile. The water draining from the pile is usually collected in a sump and either returned to the water bath below the boiler or managed as low volume waste. Such mechanical drag systems are considered as one available technology that may be used to achieve proposed limitations and standards under Options 4a (for units >400 MW), 4, and 5. Other technologies serving as the basis for limitations and standards proposed under Options 4a (for units >400 MW), 4, and 5 are completely dry bottom ash systems, remote mechanical drag systems, and impoundment-based systems that are managed to eliminate the discharge of all bottom ash transport water and the associated pollutants.

In developing the technologies that serve as the basis for the regulatory options with respect to bottom ash transport water, EPA considered basing one or more options on chemical precipitation treatment technology, with numeric effluent limitations or standards for discharges of the wastestream to surface waters. Upon reviewing the discharge flow rates for bottom ash transport water, however, EPA determined that the costs associated with treatment were comparable to the cost of the technologies upon which Options 4a (for units more than 400 MW), 4, and 5 are based, despite being less effective at removing pollutants. Since the costs for chemical precipitation treatment were found to be higher than the cost for converting to dry handling or closed loop technologies, and the treatment technology removes fewer pollutants, EPA did not include chemical precipitation treatment as part of the regulatory options for bottom ash in this proposed rule. See DCN SE03869.

As described below in this section of the preamble, EPA is proposing that certain BAT limitations for existing sources under Options 4a (for units more than 400 MW), 4, or 5 would apply to discharges of bottom ash transport water generated after the date established by the permitting authority or control authority that is as soon as possible within the next permit cycle after July 1, 2017. For indirect dischargers, EPA is proposing that PSES for bottom ash transport water would apply to bottom ash transport water generated after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Bottom ash transport water generated by existing direct dischargers prior to that date (i.e., "legacy" wastewater) would remain subject to the existing BPT effluent limits. EPA considered subjecting legacy bottom ash transport water (i.e., the bottom ash transport water generated prior to the date established by the permitting authority or control authority, as described above), to the BAT and PSES zero discharge requirement considered under Options 4a (for units more than 400 MW), 4, and 5. As explained above, currently, bottom ash transport wastewater and the associated pollutants are sent to surface impoundments for treatment prior to discharge. The technology bases identified above for Options 4a (for units more than 400 MW), 4, and 5 eliminate the generation of the bottom ash wastewater but do not eliminate bottom ash transport wastewater that has already been transferred to a surface impoundment. The technologies identified as the basis for bottom ash transport water discharge requirements under Options 4a (for units more than 400 MW), 4, and 5 have not been demonstrated for the legacy bottom ash transport wastewater that has already been generated and do not represent BAT/PSES with respect to legacy bottom ash wastewater. As such, under Options 4a (for units more than 400 MW), 4, and 5 EPA would not establish BAT or PSES requirements for discharges of legacy bottom ash transport water generated prior to the date established by the permitting authority. As proposed today, discharges of legacy bottom ash transport water by existing direct dischargers would remain subject to the existing BPT effluent limits; however, EPA is also considering whether to set the BAT effluent limitations for legacy bottom ash transport water equal to the existing BPT effluent limits. See Section XVI for additional information.

*Combustion Residual Leachate.* Under Options 1, 3a, 2, 3b, 3, and 4a, effluent limitations and standards for leachate from surface impoundments and landfills containing combustion residuals would be set equal to the current BPT effluent limitations, based on the technology of gravity settling in surface impoundments to remove

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suspended solids. Leachate is currently included under the definition of low volume wastes, which are regulated by effluent limits for TSS and oil and grease based on surface impoundments designed to remove suspended solids. EPA is proposing that under Options 1, 3a, 2, 3b, 3, and 4a, the rule would remove leachate from the definition of low volume wastes at 40 CFR 423.11(b) and would set BAT effluent limits for leachate equal to BPT limits for TSS and oil and grease (i.e., the current effluent limits for low volume wastes).

The technology basis for effluent limitations and standards for leachate under Options 4 and 5 is chemical precipitation/coprecipitation. This same technology is the basis for BAT Option 1 for FGD wastewater. Properly designed and operated surface impoundments can effectively remove suspended solids, including pollutants such as particulate forms of certain metals when associated with the suspended solids. However, since surface impoundments are not designed for, nor are they effective at, removing other pollutants of concern such as dissolved metals, EPA used chemical precipitation/coprecipitation as the technology basis for Options 4 and 5. Physical/chemical treatment systems are capable of achieving low effluent concentrations of various metals and are effective at removing many of the pollutants of concern present in leachate discharges to surface waters. The pollutants of concern in leachate are the same pollutants that are present in, and in many cases are also pollutants of concern for, FGD wastewater, fly ash transport wastewater, bottom ash transport water, and other combustion residuals. This is to be expected since the leachate itself comes from landfills and surface impoundments containing the combustion residuals and those wastes are the source for the pollutants entrained in the leachate. Given the similarities present among the different types of wastewaters associated with combustion residuals, combustion residual leachate will be similarly amenable to chemical precipitation treatment. The treatability of pollutants such as arsenic and mercury using chemical precipitation technology is also demonstrated by technical information compiled for ELGs promulgated for other industry sectors. See, e.g., the TDDs supporting the ELGs for the Landfills Point Source Category (EPA–821–R–99–019) and the ELGs for the Metal Products and Machinery Point Source Category (EPA–821–B–03–001). However, as is the case when treating FGD wastewater, this technology is not effective at removing selenium, boron and certain other parameters that contribute to total dissolved solids (e.g., magnesium, sodium).

EPA also considered developing a regulatory option that, for leachate, would be based on the technology of chemical precipitation/coprecipitation used in conjunction with anoxic/anaerobic biological treatment. This is the same technology used as the basis for effluent limitations and standards for FGD wastewater under Options 2, 3b (for units at facilities with a total wet-scrubbed capacity of 2,000 MW or more), 3, 4a, and 4. EPA has reviewed this technology as a potential basis for effluent limitations and standards for leachate and the TDD presents information about the compliance costs and pollutant removals associated with this technology. The microorganisms used in the bioreactors for the biological treatment technology for FGD wastewater are resilient and have shown that they operate effectively under varying conditions that occur in FGD system and the FGD wastewater treatment system. However, leachate flows can be more variable than FGD wastewater and, more importantly, may be too intermittent to facilitate reliable and consistent biological treatment. Such variations are easily accommodated in a chemical precipitation treatment system, but may be difficult to manage in a biological treatment system reliant on healthy and sustainable populations of microorganisms.

If EPA did finalize BAT effluent limits developed under Options 4 or 5 would (although it is not proposing such limits as a preferred option today), EPA's intent is that these limits would apply to discharges of leachate generated after the date established by the permitting authority that is as soon as possible within the next permit cycle after July 1, 2017. For indirect dischargers, PSES for leachate would apply to leachate generated after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Leachate generated by existing direct dischargers prior to that date (i.e., "legacy" leachate wastewater) would remain subject to the existing BPT effluent limits. EPA considered subjecting legacy leachate wastewater to the proposed BAT and PSES limitations and standards. However, although some plants use relatively small surface impoundments to treat leachate and these impoundments would contain relatively small volumes of legacy leachate wastewater, other plants send leachate to relatively large surface impoundments that also contain other plant wastewaters, such as fly ash or bottom ash transport water, cooling water, and/or other low volume wastes. EPA does not have the data to demonstrate that the technologies identified above represent BAT for legacy combustion residual leachate. As such, EPA would not expect to finalize BAT requirements associated with discharges of legacy combustion residual leachate (i.e., the leachate generated prior to the date established by the permitting authority or control authority). As proposed today, discharges of legacy combustion residual leachate by existing direct dischargers would remain subject to the existing BPT effluent limits; however, EPA is also considering whether to set the BAT effluent limitations for legacy combustion residual leachate that has not been mixed with non-legacy wastes equal to the existing BPT effluent limits. See Section XVI for additional information.

*FGMC Wastewater.* Under Options 1 and 2, effluent limitations and standards for FGMC wastewater would be set equal to the current BPT effluent limitations, based on the technology of gravity settling in surface impoundments to remove suspended solids. Like leachate, FGMC wastewater is currently included under the definition of low volume wastes, with effluent limits for TSS and oil and grease based on surface impoundments designed to remove suspended solids. EPA is proposing that under all options, FGMC wastewater would be removed from the definition of low volume wastes at 40 CFR 423.11(b). Under Options 1 and 2, BAT effluent limits for FGMC wastewater would be set equal to BPT limits for TSS and oil and grease (i.e., the current effluent limits for low volume wastes).

As discussed above in Section VI of this preamble, some plants inject dry sorbents (e.g., activated carbon) into the flue gas stream to reduce mercury emissions from the flue gas. Mercury adsorbs to the sorbent particles, and these mercury-enriched sorbents are then removed from the flue gas using a fabric filter or ESP. The sorbent can be injected upstream of the primary particulate collector, in which case the mercury-enriched sorbent is collected with the majority of the fly ash. Alternatively, the sorbent can be injected downstream of the primary particulate collector and collected with a much smaller amount of fly ash (i.e., the fly ash that passed through the primary collector) in a smaller, dedicated secondary particulate collector such as a fabric filter. In either case, the plant collects the mercury-

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enriched sorbents along with fly ash. Because of this, the BAT technology basis for FGMC wastewater in this proposal is identical to the BAT technology basis for fly ash.

Under Options 3a, 3b, 3, 4a, 4, and 5, EPA would establish "zero discharge" effluent limitations and standards for discharges of pollutants in FGMC wastewater based on using dry handling technologies to store and dispose of fly ash without utilizing transport water. The dry handling technologies that would be used for FGMC wastes are identical to the dry fly ash handling technologies described above in section VI of this preamble and in the TDD for the proposed rule. Although surface impoundments can effectively remove particulate forms of metals and other pollutants, they are not designed for nor are they effective at removing other pollutants of concern such as dissolved metals and nutrients. Effluent limits based on dry handling would completely eliminate the discharge of pollutants in FGMC wastewater.

EPA is also aware of some plants that add oxidizers to the coal prior to burning the coal in the boiler. This chemical addition oxidizes the mercury present in the flue gas, which allows the plant to remove mercury more readily from the flue gas in the wet FGD system. EPA did not evaluate separate treatment technologies for the use of oxidizers to control flue gas mercury emissions because using oxidizers does not generate a separate FGMC wastewater.

To the extent that a power plant generates FGMC wastewater before any BAT zero discharge limitation were to apply, the proposed BAT limitations under Options 3a, 3b, 3, 4a, 4, and 5 would apply to discharges of FGMC wastewater generated after the date established by the permitting authority that is as soon as possible within the next permit cycle after July 1, 2017. For indirect dischargers, EPA is proposing that PSES for FGMC wastewater would apply to FGMC wastewater generated after a date determined by the control authority that is as soon as possible beginning July 1, 2017. As proposed today, legacy FGMC wastewater generated by existing direct dischargers prior to that date would remain subject to the existing BPT effluent limits; however, EPA is also considering whether to set the BAT effluent limitations for legacy FGMC wastewater equal to the existing BPT effluent limits. EPA considered subjecting legacy FGMC wastewater to the proposed BAT/PSES zero discharge requirements. As explained above, although most FGMC wastes are managed using dry handling systems, EPA has identified six plants that manage their FGMC waste with systems that use water to transport the waste to surface impoundments. The technology basis identified above for the proposed zero discharge requirement eliminates the generation of the FGMC wastewater by implementing certain process changes that do not use water to transport the FGMC waste; however, it does not eliminate the already-generated FGMC wastewater that has already been transferred to and stored in a surface impoundment. The technologies that underlie regulatory Options 3a, 3b, 3, 4a, 4, and 5 do not represent BAT or PSES for the control of pollutants from legacy FGMC wastewater and would not allow FGMC wastewater that has already been generated to comply with a zero discharge requirement. As such, EPA is not proposing BAT or PSES requirements associated with discharges of legacy FGMC wastewater generated prior to the date established by the permitting authority or control authority. However, EPA is considering whether to set the BAT effluent limitations for legacy FGMC wastewater equal to the existing BPT effluent limits. See Section XVI for additional information.

*Gasification Wastewater.* The technology basis for the effluent limitations for all eight regulatory options for gasification wastewater is vapor-compression evaporation. Two operating IGCC plants in the U.S. currently use this technology, and a third IGCC plant that is scheduled to begin commercial operation soon will also use it to treat gasification wastewater. Like leachate and FGMC wastewater, gasification wastewater is currently included under the definition of low volume wastes, with effluent limits for TSS and oil and grease based on surface impoundments designed to remove suspended solids. EPA considered using surface impoundments as the technology basis for one or more of the regulatory options for gasification wastewater. However, surface impoundments are not effective at removing the pollutants of concern present in gasification wastewater. In addition, one of the currently operating IGCC plants formerly used a surface impoundment to treat its gasification wastewater and the impoundment effluent repeatedly exceeded NPDES permit limits established to protect water quality. Because of the demonstrated inability of surface impoundments to remove the pollutants of concern and the current industry practice of operating vapor-compression evaporation to treat the gasification wastewater at all U.S. IGCC plants, EPA determined that surface impoundments do not represent BAT level of control.

In addition to the vapor-compression evaporation technology that is the basis for all BAT and BADCT/NSPS options for gasification wastewater, EPA considered also including cyanide treatment as part of the technology basis for one or more options. EPA notes that the Edwardsport IGCC plant that is scheduled to soon begin commercial operation includes cyanide destruction as one step in the treatment process for gasification wastewater. However, EPA currently does not have sufficient gasification wastewater data with which to calculate effluent limits based on the performance of cyanide treatment as part of a BAT/BADCT (NSPS) regulatory option. A possible approach to resolve this would be to transfer effluent limits for cyanide from an ELG for another industry sector. Alternatively, EPA may obtain effluent data from the gasification wastewater treatment system for the Edwardsport IGCC unit once it begins commercial operation and use these data to calculate effluent limitations for cyanide. EPA solicits data on the concentrations of cyanide present in gasification wastewater and solicits comment on whether EPA should establish BAT or BADCT (NSPS) control on the discharge of cyanide.

*Nonchemical Metal Cleaning Wastes.* The technology basis for the effluent limitations for all eight regulatory options for nonchemical metal cleaning wastes is chemical precipitation. Separation processes in the physical/chemical treatment, along with chemical addition when needed to facilitate coagulation and settling of suspended solids, would effectively remove TSS and oil and grease to effluent concentrations below the limitations included in the proposed rule. In addition, treatment chemicals added to adjust pH to precipitate dissolved metals or to facilitate flocculation/coagulation are effective at removing copper and iron to effluent concentrations below the proposed limitations, in addition to reducing the concentrations of other pollutants present in nonchemical metal cleaning wastes.

The current ELG relies on three key terms specific to metal cleaning waste: "metal cleaning waste," "chemical metal cleaning waste," and "nonchemical metal cleaning waste." The regulation includes a definition of the broadest term, "metal cleaning waste," as "any wastewater resulting from cleaning [with or without chemical cleaning compounds] any metal process equipment, including, but not limited to, boiler tube cleaning, boiler fireside

cleaning, and air preheater cleaning." 40 CFR 423.11(d). Thus, this definition includes *any* wastewater generated from *either the chemical or nonchemical cleaning* of metal process equipment. In addition, the regulation also defines "chemical metal cleaning waste" as "any wastewater resulting from cleaning of any metal process equipment with chemical compounds, including, but not limited to, boiler tube cleaning." See 40 CFR 423.11(c). The regulation also includes, but does not expressly define the term "nonchemical metal cleaning waste" when it states that it has "reserved" the development of BAT ELGs for such wastes. See 40 CFR 423.13(f). Although the regulation provides no definition of "nonchemical metal cleaning waste," it is clear from the definitions of *metal cleaning waste* and *chemical metal cleaning waste* that *nonchemical metal cleaning waste* is any wastewater resulting from the cleaning of metal process equipment without chemical cleaning compounds.

The current ELGs include BPT effluent limits for the allowable levels of TSS, oil and grease, copper and iron in discharges of metal cleaning waste, which includes both chemical and nonchemical metal cleaning wastes. Although the current BPT effluent limits apply to nonchemical metal cleaning wastes, EPA has found that some discharges of nonchemical metal cleaning waste are authorized pursuant to permits incorporating limitations based on BPT requirements for low volume wastes and, therefore, do not have iron and copper limits. The information EPA has collected to date indicates many facilities are not discharging nonchemical metal cleaning wastewater or have copper and iron limits (see Section VIII.A.3 and Section 7.7 of the TDD for more information).

The current ELGs do not include BAT/NSPS requirements for the broadly defined category of metal cleaning wastes; however, they do include BAT/NSPS for chemical metal cleaning waste. EPA has not promulgated BAT/NSPS for nonchemical metal cleaning waste. Similarly, although the current ELGs do not include PSES/PSNS for metal cleaning waste, they do include PSES/PSNS for chemical metal cleaning waste. EPA has not promulgated PSES/PSNS for nonchemical metal cleaning waste. An overview of the existing ELGs for metal cleaning waste, including chemical and nonchemical metal cleaning waste, is provided below in Table VIII–2.

TABLE VIII–2—PARAMETERS LIMITED BY EXISTING ELGS FOR METAL CLEANING WASTE

| Wastestream | BPT | BAT | NSPS | PSES | PSNS |
|---|---|---|---|---|---|
| Chemical Metal Cleaning Waste. | TSS, Oil & Grease, Copper, Iron. | Copper, Iron | TSS, Oil & Grease, Copper, Iron. | Copper | Copper. |
| Nonchemical Metal Cleaning Waste. | | *Reserved* | *Reserved* | *Reserved* | *Reserved.* |

As described above, EPA found that some discharges of nonchemical metal cleaning waste are authorized pursuant to permits incorporating limitations based on BPT requirements for low volume wastes and, therefore, do not have iron and copper limits. Because the potential costs for dischargers to comply with iron and copper limits is not known, EPA is proposing to provide an exemption from new copper and iron limitations or standards for existing discharges of nonchemical metal cleaning wastes from generating units that are currently authorized without iron and copper limits. For these discharges, BAT limitations for nonchemical metal cleaning waste would be set equal to BPT limitations for low volume waste, and the regulations would not specify PSES. EPA solicits comment on the specific generating units that should be included in the exemption. See Section VIII.A.3 for additional details regarding the information that EPA is requesting as part of the comment solicitation.

EPA is also considering setting BAT for nonchemical metal cleaning waste equal to the metal cleaning waste BPT for all nonchemical metal cleaning wastes (i.e., no exemption for discharges of nonchemical metal cleaning wastes currently authorized without iron and copper limits) and, for PSES, to establish copper standards for all discharges of nonchemical cleaning wastes. As part of this approach, EPA is evaluating whether some plants would incur costs to comply with the current BPT standards. Therefore, as described later in this preamble, EPA is also soliciting comments associated with each generating unit with discharges of nonchemical metal cleaning wastes that are not currently subject to the BPT copper and iron limits, in order to understand the nonchemical metal cleaning wastes that are generated, the characteristics of the wastewater, what actions would be needed to comply with the proposed copper and iron limits, and estimated costs associated with those actions. See Section VIII.A.3 for details regarding the information that EPA is requesting as part of the comment solicitation.

*Anti-Circumvention Provisions.* EPA is proposing to add provisions to the regulations that would prevent facilities from circumventing the effluent limitations guidelines and standards. The proposed provisions would do three things, as described below.

First, the anti-circumvention provision would require that compliance with the new effluent limits applicable to a particular wastestream (e.g., FGD, gasification wastewater, leachate) be demonstrated prior to use of the wastewater in another plant process that results in surface water discharge or mixing the treated wastestream with other wastestreams. Under 40 CFR 122.45(h), in situations where an NPDES permit effluent limitations or standards imposed at the point of discharge are impractical or infeasible, effluent limitations or standards may be imposed on internal wastestreams before mixing with other wastestreams or cooling water streams. Limitations on internal wastestreams may be necessary, such as in situations where the wastes at the point of discharge are so diluted as to make monitoring impracticable, or the interferences among pollutants would make detection or analysis impracticable. Many power plants combine FGD wastewater and other power plant wastewaters with ash transport water and/or cooling water prior to discharge, which can dilute the wastewaters by several orders of magnitude prior to the final outfall. In addition, surface impoundments typically contain a variety of wastes (e.g., ash transport water, coal pile runoff, landfill/impoundment leachate) that when mixed with the FGD wastewater or gasification wastewater may make the analysis to measure compliance with technology-based effluent limits impracticable. Because of the high degree of dilution and the number of wastestream sources containing similar pollutants, effluent

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limits and monitoring requirements for certain internal wastestreams (e.g., FGD wastewater, combustion residual leachate, gasification wastewater) are necessary to ensure appropriate control of the pollutants present in the wastewater. EPA requests comment on the extent, if any, to which this provision may discourage water re-use.

Second, the anti-circumvention provision would establish requirements intended to prevent steam electric power plants from circumventing the effluent limits and standards by moving effluent produced by a process operation for which there is a zero discharge effluent limit/standard to another process operation for discharge under less stringent requirements than intended by the steam electric ELGs. For example, several options (including Option 3a) considered in this rulemaking would establish a zero discharge requirement for pollutants in fly ash transport water and FGMC wastewater. If this option were selected for the final rule, the anti-circumvention provisions would allow power plants to recycle/reuse these wastestreams in ash transport processes or other plant processes, but only to the extent that the plants do not discharge any pollutants associated with flue gas mercury controls or transporting fly ash. The presence of a zero discharge wastestream in a process that ultimately discharges to surface water (e.g., use of fly ash transport water as FGD absorber make-up water in a scrubber that discharges FGD wastewater) would not be in compliance with the effluent limit. EPA requests comment on the extent to which this provision may discourage water re-use.

Last, the anti-circumvention provisions would expressly require permittees to use analytical EPA-approved methods that are sufficiently sensitive to provide reliable quantified results at levels necessary to demonstrate compliance with the effluent limits proposed by this rulemaking when such methods are available. EPA's detailed study and the field sampling for this rulemaking demonstrate that the use of sufficiently sensitive analytical methods is critically important to detecting, identifying, and measuring the concentrations of pollutants present in power plant wastewaters. Where EPA has approved more than one analytical method for a pollutant, the Agency expects that permittees would select methods that are able to quantify the presence of pollutants in a given discharge at concentrations that are low enough to determine compliance with effluent limits, when such methods are available. Facilities should not use a less sensitive or less appropriate method, thus masking the presence of a pollutant in the discharge, when an EPA-approved method is available that can quantify the pollutant concentration at the lower levels needed for demonstrating compliance. For purposes of the proposed anti-circumvention provision, a method is "sufficiently sensitive" when the sample-specific quantitation level [23] for the wastewater being analyzed is at or below the level of the effluent limitation. Allowing plants to use insufficiently sensitive analytical methods for compliance monitoring purposes when EPA-approved sufficiently sensitive methods are available could result in an undetected exceedance of the effluent limits.

*BMPs for CCR Surface Impoundments.* EPA is considering establishing BMPs for plant operators to conduct periodic inspections of active and inactive surface impoundments and to take corrective actions where warranted. This requirement would apply to direct dischargers. For new sources, EPA would be relying on CWA section 306, which authorizes the promulgation of standards of performance for new sources. For existing sources, EPA would be relying on CWA section 304(e), which authorizes BMPs supplemental to ELGs for toxic or hazardous pollutants to control plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage which the Administrator determines are associated with or ancillary to the industrial process and may contribute significant amounts of pollutants to the nation's waters. And CWA section 402(a) (2) authorizes the imposition of conditions, which would include BMPs and monitoring requirements, necessary to ensure compliance with all other applicable requirements. EPA's regulation at 40 CFR 122.44(k) implements these authorities. Specifically, 40 CFR 122.44(k) allow for NPDES permits to require the use of BMPs to control and abate the discharge of toxic pollutants. Existing regulations at 40 CFR 122.41(e) further require that NPDES permittees properly operate and maintain all facilities and systems of treatment and control used to achieve compliance with their permits. This action provides notification that EPA is considering establishing BMP requirements to address impoundment construction, operation, and maintenance in the final ELG rule using CWA authority. Using CWA authority, EPA could establish the BMPs as part of the ELGs (BAT and NSPS) codified at 40 CFR part 423, and thus these BMPs would be implemented through NPDES permits. Structural integrity requirements that seek to reduce the potential for catastrophic releases from surface impoundments could, alternatively, be established using RCRA authority. The BMPs under consideration in this rulemaking are similar to the structural integrity inspection and corrective active requirements proposed in the CCR rulemaking, but do not include closure requirements that were proposed as part of the CCR rulemaking.

The Agency believes that the BMP requirements being considered by the Agency in this rulemaking and in the CCR rulemaking are critical to ensure that the owners and operators of surface impoundments become aware of any problems that may arise with the structural stability of the surface impoundment before they occur and, thus, prevent catastrophic releases, such as those that occurred at Martins Creek, Pennsylvania and TVA's Kingston, Tennessee facility.

The BMPs being considered by EPA in this rulemaking would require, first, that inspections be conducted every seven days by a person qualified to recognize specific signs of structural instability and other hazardous conditions by visual observation and, if applicable, to monitor instrumentation such as piezometers. If a potentially hazardous condition develops, the owner or operator shall immediately take action to eliminate the potentially hazardous condition; notify the Regional Administrator or the authorized State Director; and notify and prepare to evacuate, if necessary, all personnel from the property that may be affected by the potentially hazardous condition(s). Additionally, the owner or operator must notify state and local emergency response personnel if conditions warrant so that people living in the area down gradient from the surface impoundment can evacuate. Reports of inspections are to be maintained in the facility operating record.

Second, to address the integrity of surface impoundments, EPA would establish BMPs for CCR surface impoundments similar to those promulgated for coal slurry impoundments regulated by the Mine Safety and Health Administration (MSHA) at 30 CFR 77.216. Although the

[23] For the purposes of this rulemaking, EPA is considering the following terms related to analytical method sensitivity to be synonymous: "quantitation limit," "reporting limit," "level of quantitation," and "minimum level."

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MSHA regulations are applicable to coal slurry impoundments at coal mines and not to the impoundments containing CCR at power plants, there are sufficient similarities between coal slurry and CCR impoundments for the MSHA regulations to be used as a model for the BMP requirements being considered for the ELG rule. Facilities using CCR impoundments would need to (1) submit to EPA or the authorized state plans for the design, construction, and maintenance of existing impoundments, (2) submit to EPA or the authorized state plans for closure, (3) conduct periodic inspections by trained personnel who are knowledgeable in impoundment design and safety, and (4) provide an annual certification by an independent registered professional engineer that all construction, operation, and maintenance of impoundments is in accordance with the approved plan. When problematic stability and safety issues are identified, owners and operators would be required to address these issues in a timely manner.

In developing these possible structural integrity BMP requirements, EPA sought advice from the federal agencies charged with managing the safety of dams in the United States. Many agencies in the federal government are charged with dam safety, including the U.S. Department of Agriculture (USDA), the Department of Defense (DOD), the Department of Energy (DOE), the Nuclear Regulatory Commission (NRC), the Department of Interior (DOI), and the Department of Labor (DOL), MSHA. EPA looked particularly to MSHA, whose charge and jurisdiction appeared to EPA to be the most similar to the Agency's in this context. MSHA's jurisdiction extends to all dams used as part of an active mining operation and their regulations cover "water, sediment or slurry impoundments" so they include dams for waste disposal, freshwater supply, water treatment, and sediment control. In fact, MSHA's current impoundment regulations were created as a result of the dam failure at Buffalo Creek, West Virginia on February 26, 1972. (This failure released 138 million gallons of stormwater run-off and fine coal refuse, and resulted in 125 persons killed, another 1,000 injured, over 500 homes completely destroyed, and nearly 1,000 others damaged.)

MSHA has nearly 40 years of experience writing regulations and inspecting dams associated with coal mining. MSHA's regulations are comprehensive and directly applicable to the dams used in surface impoundments at coal-fired utilities to manage CCRs. EPA believes that, based on the record compiled by MSHA for its rulemaking, and on MSHA's 40 years of experience implementing these regulations, the requirements being considered in this rulemaking would substantially reduce the potential for catastrophic release of CCRs from surface impoundments, as occurred at TVA's facility in Kingston, Tennessee, and would generally meet RCRA's objective to ensure the protection of humans and the environment.[24] Thus, EPA is considering establishing BMPs that would be modeled on MSHA regulations in 30 CFR part 77.

MSHA's regulations for coal slurry impoundments apply to those impoundments at coal mines, which impound water, sediment or slurry to an elevation of more than five feet and have a storage volume of 20 acre-feet or more and those coal slurry impoundments that impound water, sediment, or slurry to an elevation of 20 feet or more. The BMPs being considered today for the ELG rule would apply to all CCR impoundments at steam electric power generating facilities, regardless of height and storage volume. EPA is also considering variations on BMPs for the ELGs, including, but not limited to, different inspection frequencies or limitations on the applicability of BMPs that more closely mirror the applicability of the MSHA regulations. EPA requests comment on possible BMPs for inclusion in a final ELG rule including those described above and any other appropriate variations on them.

*Voluntary Incentive Program for Power Plants That Close CCR Impoundments or Eliminate All Process Wastewater Discharges (Except Cooling Water).* EPA is considering establishing, as part of the BAT for existing sources, a voluntary incentive program that provides more time for plants to implement the proposed BAT requirements if they adopt additional process changes and controls that provide significant environmental protections beyond those achieved by the preferred options for this proposed rule. The development of advanced process changes and controls is a critical step toward the Clean Water Act's ultimate goal of eliminating the discharge of pollutants into the Nation's waters. See CWA Section 101(a)(1). Section 301(b)(1)(C) demands that BAT result in "reasonable further progress toward the national goal of eliminating the discharge of pollutants." EPA intends that, for any BAT option that is ultimately selected as part of any final ELG rule, such option would represent "reasonable further progress," while the voluntary incentives program is designed to continue progress toward achieving the national goal of the Act. In addition, Section 104(a)(1) of the Act gives the Administrator authority to establish national programs for the prevention, reduction, and elimination of pollution, and it provides that such programs shall promote the acceleration of research, experiments, and demonstrations relating to the prevention, reduction, and elimination of pollution. The voluntary incentives program being considered today would effectively accelerate the research into and use of controls and processes intended to prevent, reduce, and eliminate pollution because it would increase the number of plants choosing to close and cap CCR surface impoundments and eliminate discharges of all process wastewater (except cooling water) to surface waters.

This voluntary program would establish two levels, or "tiers," of advanced technology performance requirements which would be incorporated into the NPDES permits for the facilities that participate in the program. Under Tier 1, power plants would be granted two additional years (beyond the time described below in Section VIII.B) if they also dewater, close and cap all CCR surface impoundments (except for those impoundments containing only combustion residual leachate) at the facility, including those surface impoundments located on non-adjoining property that receive CCRs from the facility. A power plant participating in the Tier 1 program could continue to operate surface impoundments for which combustion residual leachate is the only type of CCR solids or wastewater contained in the impoundment. In general, power plants accepted in the Tier 1 incentives program would first convert ash handling operations to dry handling or closed-loop tank-based systems and FGD wastewater treatment operations to tank-based systems, as described above in Section VI. This first step would eliminate new contributions of CCRs (solids and wastewater) to the surface impoundments. The plants would then dewater the impoundments by draining

[24] On December 22, 2008, the retention wall of a coal ash impoundment at Tennessee Valley Authority's Kingston Plant collapsed, which resulted in a massive release of CCRs directly into the Emory River and its tributaries. The Emory River joins to the Clinch River and then converges with the Tennessee River, a major drinking water source for populations downstream. This failure released over a billion gallons of fly ash and bottom ash, which impacted over 100 properties, destroyed three homes, and ruptured a gas line resulting in the evacuation of 22 residents.

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or pumping the wastewater from the impoundments, in compliance with the ELGs and other requirements established in their NPDES permits. Upon completing the dewatering operations, plants would then stabilize the contents and close and cap the impoundments consistent with state requirements and any other additional requirements that may be established by EPA as part of the Tier 1 incentives program or other applicable requirements.

Under Tier 2, power plants would be granted five additional years (beyond the time described below in Section VIII.B) if they eliminate the discharge of all process wastewater to surface waters, with the exception of cooling water discharges. The Tier 2 incentives would not be available to power plants that eliminate direct discharge to surface water by sending the wastewater to a POTW. A plant accepted into the Tier 2 incentives program would ultimately need to manage its processes and wastewater in a manner that implements a coordinated approach toward wastewater minimization, treatment and reuse. To achieve Tier 2 status, these plants would eliminate all process wastewater discharges (except cooling water) by reducing the amount of wastewater generated and preferentially using recycled wastewater to meet water supply demands. To accomplish this, Tier 2 plants would conduct engineering assessments of the processes that generate wastewater and identify opportunities to eliminate or reduce the amount of wastewater they generate. These plants would also assess the processes that use water and determine how they could use recycled wastewater in those processes, as well as the degree of treatment that may be needed to enable such reuse. Based on responses to the industry survey, EPA has identified a number of steam electric power plants that currently discharge no process wastewater. In addition, two of the plants that EPA visited in Italy previously discharged process wastewater, but have implemented wastewater treatment and process changes, including wastewater recycle, that now allow them to operate without discharging any process wastewater except for their cooling water.

The primary objective of this program is to encourage individual power plants to install advanced pollution prevention technologies or make process changes that would further reduce releases of toxic pollutants to the environment beyond the limits that would be set by the proposed rule. The voluntary incentive program being considered is designed to promote improvements that, in concert with other environmental practices, make significant progress toward achieving EPA's vision of the "power plant of the future"—one which will have a minimum impact on the environment. This program would give power plants a platform to advance the research and development of technologies and processes that promote water conservation and water recycling and provide greater environmental protection. EPA has conducted site visits at power plants that have implemented processes that eliminate the use of water or recycle process wastewater to a substantial degree. Furthermore, as noted above, EPA observed operations at power plants that implemented process modifications and treatment technologies that eliminated all discharges of process wastewater with the exception of their cooling water. Implementing such practices at other power plants would dramatically reduce discharges of toxic and other pollutants. These practices would also substantially reduce the amount of water consumed or used by the plant, which could be an important consideration for addressing water availability and other concerns. In exchange for providing additional time for power plants to comply with the proposed BAT limitations, the program would lead to superior effluent quality and greater environmental protection.

Participation in the program would be voluntary and it would be available only to existing power plants that discharge directly to surface waters. Power plants would have until July 1, 2017 (approximately 3 years after promulgation of the final ELGs) to commit to the program and submit a plan for achieving the Tier 1 or Tier 2 requirements. Once a power plant enrolls in the program, the NPDES permitting authority would develop specific discharge limits and key milestones consistent with that tier.

Power plants enrolled in the program would ultimately be agreeing to adopt NPDES permit limits that are more stringent than those that would be required by the proposed and final BAT in exchange for additional time to comply with their new effluent limitations. These power plants and their corporate owners would also receive public recognition for their commitment to increased environmental protection.

EPA considered including features of the Tier 1 and Tier 2 incentives as part of the options for the proposed rule. However, although EPA has observed these practices in operation and they are available for at least a portion of the industry, the degree of complexity will vary from plant to plant and EPA does not have the site-specific information that could be used to sufficiently assess how that complexity may affect the engineering challenges and costs that plants would encounter. EPA requests comment on the voluntary incentives program described in this section and any appropriate variations.

3. Rationale for the Proposed Best Available Technology (BAT)

BAT represents the best available economically achievable performance of facilities in an industrial subcategory or category taking into account factors specified in the CWA. The CWA factors considered in assessing BAT are the cost of achieving BAT effluent reductions, the age of equipment and facilities involved, the process employed, potential process changes, and non-water quality environmental impacts, including energy requirements and such other factors as the Administrator deems appropriate. See Section 304(b)(2)(B). In addition to technological availability, economic achievability is also a factor considered in setting BAT. See Section 301(b)(2)(A).

After considering all of the technologies described in Section VII.B.2, in light of the factors specified in Section 304(b)(2)(B) and Section 301(b)(2)(A) of the CWA, as appropriate, EPA is putting forth four preferred alternatives for BAT. These four preferred alternatives primarily differ in that some would establish more environmentally protective BAT requirements for discharges from two of the wastestreams from existing sources. Under the first preferred alternative, EPA is proposing to establish BAT effluent limits based on the technologies specified in Option 3a. With the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller), the proposed rule under Option 3a would:

- Establish a "zero discharge" effluent limit for all pollutants in fly ash transport water and FGMC wastewater;
- Establish numeric effluent limits for mercury, arsenic, selenium, and TDS in discharges of gasification wastewater;
- Establish numeric effluent limits for copper and iron in discharges of nonchemical metal cleaning wastes [25];
- Establish BAT effluent limits for bottom ash transport water and

[25] As described later in this section, EPA is proposing to exempt from new BAT copper and iron limitations existing discharges of nonchemical metal cleaning wastes that are currently authorized under their existing NPDES permit without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits for low volume waste.

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combustion residual leachate that are equal to the current BPT effluent limits for these discharges (i.e., numeric effluent limits for TSS and oil and grease; and

- BAT for discharges of FGD wastewater would continue to be determined on a site-specific basis.

Under the second preferred alternative for BAT, EPA is proposing to establish BAT effluent limits based on the technologies specified in Option 3b. With the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller), the proposed rule under Option 3b would:

- Establish numeric effluent limits for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater for units located at plants with a total wet-scrubbed capacity of 2,000 MW or more [26] [27];
- Establish a "zero discharge" effluent limit for all pollutants in fly ash transport water and FGMC wastewater;
- Establish numeric effluent limits for mercury, arsenic, selenium, and TDS in discharges of gasification wastewater;
- Establish numeric effluent limits for copper and iron in discharges of nonchemical metal cleaning wastes [28]; and
- Establish BAT effluent limits for bottom ash transport water and leachate that are equal to the current BPT effluent limits for these discharges (i.e., numeric effluent limits for TSS and oil and grease).

Under the third preferred alternative for BAT, EPA is proposing to establish BAT effluent limits based on the technologies specified in Option 3. In addition to the requirements described for Option 3b, the proposed rule would establish the same numeric effluent limits as in Option 3b for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater from units located at all steam electric facilities, with the exception of oil-fired generating units and small generating units (i.e., 50 MW or less).

Under the fourth preferred alternative for BAT (Option 4a), in addition to the requirements described for Option 3, the proposed rule would establish "zero discharge" effluent limits for all pollutants in bottom ash transport water from units greater than 400 MW.

For oil-fired generating units and small generating units (i.e., 50 MW and smaller) that are existing sources, under all four preferred options, EPA is proposing to set the BAT effluent limits equal to the current BPT effluent limits for copper and iron for nonchemical metal cleaning wastes,[29] and for TSS and oil and grease for five of the six wastestreams listed above (i.e., FGD wastewater, fly ash transport water, FGMC wastewater, leachate from landfills and surface impoundments containing combustion residuals, and gasification wastewater). EPA is proposing Options 3a, 3b, 3 and 4a as the preferred BAT regulatory options because its analysis to this date suggests that they are all technologically available, economically achievable, and have acceptable non-water quality environmental impacts. However, EPA is putting forth a range of options as candidates for BAT in order to enhance the Agency's understanding of the pros and cons of each of these options in light of the statutory factors through the public comment process and intends to evaluate this information and how it relates to the factors specified in the CWA. As discussed above in Sections VI and VIII.A.2, the data in EPA's record and its analysis to date suggests that all four options are technologically available. EPA's record indicates that the technologies comprising Options 3a, 3b, 3, and 4a are well-demonstrated and have been employed at a subset of existing power plants.

Under all of the preferred options, the technology basis for fly ash transport water is dry handling. All generating units built in the 30 years since the ELGs were last revised in 1982 have been subject to a zero discharge standard for the pollutants in fly ash transport water, in nearly all cases installing dry fly ash handling technologies to comply with the standard. In addition, many other generating units that could discharge their fly ash transport water upon meeting a TSS effluent limit have instead retrofitted the dry fly ash handling technology to meet operational needs or for economic reasons. Approximately 40 percent of the plants that were operating wet-sluicing systems in 2000 have converted generating units to dry fly ash (approximately 115 generating units at 45 power plants). Another 61 generating units are slated to convert to dry fly ash handling by 2020. Based on data collected by the industry survey, approximately 66 percent of coal- and petroleum coke-fired generating units handle all fly ash with dry technologies. Another 15 percent of coal- and petroleum coke-fired generating units have both wet and dry fly ash handling systems (typically, the wet system is a legacy system that the plant has not decommissioned following retrofit with a dry system). Only 19 percent of coal- and petroleum coke-fired generating units exclusively use a wet fly ash handling system. Furthermore, some of these plants with wet fly ash handling systems manage the ash handling process so that they do not discharge fly ash transport water. As a result, EPA determined that only 13 percent of coal-fired power plants would incur costs to comply with a BAT zero discharge requirement for fly ash transport water. See Section 9.7.3 of the TDD.

Power plants recently began installing FGMC systems either to comply with state requirements or to prepare for emissions limits established by the MATS rule. Plants using sorbent injection systems (e.g., activated carbon injection) typically handle the spent sorbent in the same manner as their fly ash. Nearly all plants with FGMC systems use dry handling technologies. Only a few plants use wet systems to transport the spent sorbent to disposal in surface impoundments. Based on the industry survey, the plants using wet handling systems currently operate them as closed-loop systems and do not discharge FGMC wastewater to surface waters, or have the capability to do so. These plants could continue to operate these wet systems as closed-loop systems, or could convert to dry handling technologies by managing the fly ash and spent sorbent together in a retrofitted dry system (the wastes are currently managed together in the impoundments) or by installing dedicated dry handling equipment for the FGMC wastes similar to the equipment used for fly ash.

The technology basis for control of discharges of FGD wastewater under Options 3, 3b (for units located at plants with a total wet-scrubbed capacity of 2,000 MW or more), and 4a is chemical precipitation followed by anaerobic biological treatment. Four power plants, or approximately three percent of wet-scrubbed power plants that discharge FGD wastewater already have the

[26] Total plant-level wet-scrubbed capacity is calculated by summing the nameplate capacity for all of the units that are serviced by wet FGD systems.

[27] For units below the 2,000 MW threshold, BAT would continue to be determined on a site-specific basis.

[28] As described later in this section, EPA is proposing to exempt from new BAT copper and iron limitations existing discharges of nonchemical metal cleaning wastes that are currently authorized under their existing NPDES permit without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits for low volume wastes.

[29] As described later in this section, EPA is proposing to exempt from new BAT copper and iron limitations existing discharges of nonchemical metal cleaning wastes that are currently authorized under their existing NPDES permit without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits for low volume waste.

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Options 3b (for units located at plants with a total wet-scrubbed capacity of 2,000 MW or more), 3 and 4a BAT technology in place. Under Options 3b (for units located at plants with a total wet-scrubbed capacity of 2,000 MW or more), 3, and 4a, in addition to other new requirements that would be established, numeric limits would be established for toxic discharges including arsenic, mercury, and selenium from FGD wastewater.

The technology used as the basis for FGD wastewater treatment under Options 3b (for units at plants with a total wet-scrubbed capacity of 2,000 MW or more), 3 and 4a has been tested at power plants for more than 10 years and full-scale systems have been operating at a subset of plants for 5 years. The biological treatment processes used in the bioreactor portion of the treatment technology have been widely used in many industrial applications for decades both in the U.S. and internationally. Five steam electric power plants operate fixed-film anoxic/anaerobic biological treatment systems to treat FGD wastewater and another operates a suspended growth biological treatment system that targets removal of selenium.[30] Other power plants are considering installing the biological treatment technology to remove selenium and at least one plant is moving forward with construction. See DCN SE03874. In addition, four additional power plants currently operate anaerobic biological treatment systems for their FGD wastewater, indicative that this is available technology. EPA is aware of industry concerns with the feasibility of biological treatment at some power plants. Specifically, industry has asserted that the efficacy of these systems is unpredictable, and is subject to temperature changes, high chloride concentrations, and high oxidation reduction potential in the absorber (which may kill the treatment bacteria). EPA's record to date does not support these assertions, but is interested in additional information that addresses these concerns.

More than one-third of plants that discharge FGD wastewater utilize chemical precipitation (in some cases, also using additional treatment steps). As noted above, four power plants currently operate chemical precipitation systems in combination with anaerobic biological treatment systems. The chemical precipitation treatment processes included in the FGD wastewater technology basis for these options are used at 24 percent of steam electric power plants that discharge FGD wastewater (and another 11 percent of plants also use chemical precipitation systems that could be upgraded to this technology basis) and also at thousands of industrial facilities nationwide (See Section 8.1.3 of the TDD).[31]

Option 3b proposes limitations based on this technology for units at the largest plants (as determined by a 2,000 MW total wet-scrubbed capacity threshold), and BAT for the control of discharges of FGD wastewater from units at plants below this threshold would continue to be determined on a site-specific basis. For FGD wastewater only, EPA believes any threshold should be based on a plant level rather than a unit level because many plants currently use a single FGD treatment systems to service multiple units. Additionally, EPA determined that wet-scrubbed capacity is an appropriate metric because it only reflects units that are generating FGD wastewater. For example, a plant could have a total plant nameplate generating capacity of 3,500 MW, but only have a wet-scrubbed capacity of 200 MW if only one of its units is wet-scrubbed. EPA is putting forth this option as a preferred option based on an assumption that these facilities are more able to achieve these limits based on economies of scale. These largest facilities will likely also be able to absorb the costs of installing and operating the chemical precipitation and anaerobic biological treatment systems on which the FGD wastewater limitations are based. For these reasons, as well as those specified above related to current innovation and treatment trends, Option 3b proposes that BAT effluent limitations for discharges of FGD wastewater would continue to be determined on a site-specific basis for units at facilities below the 2,000 MW threshold. EPA solicits comment on the proposed 2,000 MW threshold applicable to discharges of FGD wastewater under Option 3b, including whether this or another threshold may be more appropriate.

The fourth preferred alternative for this proposed rule, Option 4a, in addition to the requirements that would be established under Option 3, would eliminate discharges of pollutants in bottom ash transport water from units greater than 400 MW. The technology basis for bottom ash for the zero discharge requirement is dry handling or a closed-loop system. Bottom ash transport water is one of the three largest sources for discharges of the pollutants of concern from steam electric power plants and these discharges occur at many power plants across the nation. Based on data collected by the industry survey, approximately 30 percent of coal-fired and petroleum coke-fired power plants handle bottom ash using technologies that do not generate any transport water. In addition, another 12 percent of coal- and petroleum coke-fired power plants manage the wet-sluicing bottom ash handling system as a closed-loop system that recirculates all bottom ash transport water so that it is not discharged. In addition, 83 percent of coal-fired generating units built in the last 20 years installed dry bottom ash handling systems.

EPA recognizes that the potential costs associated with compliance with a zero discharge standard for discharges of bottom ash transport water would be substantial if applied to all facilities (for example, approximately half of Option 4 costs and approximately a third of Option 5 costs), and, therefore, looked carefully at this wastestream with a particular focus on generating unit size. Our review demonstrated that, in the case of bottom ash transport water, units less than or equal to 400 MW are more likely to incur compliance costs that are disproportionately higher per MW than those incurred by larger units. For example, the average annualized cost of achieving zero discharge limits for bottom ash discharges (i.e. dry handling or closed loop) per MW for a 200 MW unit is more than three times higher than the average cost for a 400 MW unit. Based on the data from the industry survey, EPA estimates that 25 percent of coal-fired power plants would incur costs to comply with a BAT zero discharge requirement for bottom ash transport water from units greater than 400 MW.

Furthermore, while all plants, regardless of size, are capable of installing and operating dry handling or closed-loop systems for bottom ash transport water, and the costs would be affordable for most plants, EPA believes that companies may choose to shut down 400 MW and smaller units instead of making new investments to comply with proposed zero discharge bottom ash requirements. EPA is basing this belief on its review of units that facilities have announced will be retired or converted to non-coal based fuel sources. Of those units that plants have announced for retirement, and that also

[30] Four of the six operate the biological treatment systems in combination with chemical precipitation.

[31] Physical/chemical treatment systems can be effective at removing mercury and certain other metals; however, to achieve effective removal of selenium this technology must be coupled with additional treatment technology such as anoxic/anaerobic biological treatment.

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generate bottom ash transport water, over 90 percent are 400 MW or less. See DCN SE03834.

Therefore, for the reasons specified above, for units less than or equal to 400 MW, Option 4a proposes to set the BAT effluent limits equal to the current BPT effluent limits based on surface impoundments. EPA solicits comment on the proposed 400 MW threshold applicable to discharges of bottom ash transport water under Option 4a, including whether this or another threshold may be more appropriate.

The two IGCC plants currently operating in the United States use the technology that is the basis for all four preferred options for gasification wastewater. A third IGCC plant that will soon begin commercial operation will also use the technology and, in addition to that, will also operate a cyanide destruction step as part of the treatment system.

For all four preferred options, the proposed BAT limits for copper and iron in discharges of nonchemical metal cleaning waste are equal to the current BPT effluent limits for these pollutants in metal cleaning waste. These effluent limits are based on the same technology that was used as the basis for the current ELG BPT requirements for metal cleaning waste (i.e., chemical precipitation).

Discharges of metal cleaning wastes that are generated from cleaning metal process equipment without chemical cleaning compounds (i.e., nonchemical metal cleaning waste) are already subject to BPT effluent limits for copper and iron equal to the BAT effluent limits being proposed today. Based on responses to the industry survey, facilities typically treat both chemical and nonchemical metal cleaning waste in similar fashion.

Since, as described above, nonchemical metal cleaning waste is included within the definition of metal cleaning waste, and copper and iron are already regulated under metal cleaning wastes, EPA would be establishing BAT limits equal to the BPT limits (for copper and iron) that already apply to these wastes. As a result, facilities should incur no cost to comply with the proposed BAT for these wastes. However, EPA recognizes that previous guidance provided after the final 1974 regulation stated that wastes from metal cleaning with water are considered "low volume" wastes. The extent to which this statement was relied upon is unclear, and EPA rejected the guidance in the 1982 rulemaking for the steam electric ELGs (47 FR 52297). However, because permitting authorities and others may have relied on this guidance and the potential costs to those facilities are not known, EPA is proposing to exempt from any new copper and iron BAT requirements those discharges of nonchemical metal cleaning waste to which this guidance was applied in the past. In other words, EPA is proposing to exempt from proposed new copper and iron BAT limitations those discharges of nonchemical metal cleaning wastes from generating units that are currently authorized to discharge nonchemical metal cleaning wastes without copper and iron limits pursuant to existing BPT requirements for metal cleaning waste. For such discharges, EPA is proposing to set BAT limitations equal to BPT limitations for low volume waste.

To get a better understanding of how discharges of nonchemical metal cleaning wastes are currently permitted, EPA's regional offices recently reviewed 45 permits for plants that EPA had reason to believe generated nonchemical metal cleaning waste based on responses to the industry survey. For these permits, EPA determined the following based on the review:

- 64 percent of the plants are either zero discharge of metal cleaning wastes or have to comply with copper and iron limits;
- 27 percent of plants do not have to comply with copper and iron limits; and
- 9 percent of plant permits do not include enough information to determine whether the plant would be in compliance with the proposed BAT limitations.

While not exhaustive, this review provides some information to suggest that many, but not all, plants are either zero discharge or have iron and copper limits and thus are already meeting these proposed BAT limitations. Also see Section 7.7 of the TDD.

In order to implement the exemption proposed today for certain discharges of nonchemical metal cleaning waste that have historically been treated as low volume wastes and not subject to copper and iron limits under metal cleaning waste BPT requirements, EPA's current thinking is to develop a specific list of generating units eligible for the exemption. Therefore, EPA is seeking to identify those generating units that should be eligible for the exemption through the public comment process on this rulemaking. To qualify for the proposed exemption, the generating unit must meet all three of the following criteria:

- The generating unit must currently generate nonchemical metal cleaning wastes;
- The generating unit must discharge the nonchemical metal cleaning waste; and
- The generating unit must be located at a plant that is authorized to discharge the nonchemical metal cleaning waste without limitations for copper and iron.

If the nonchemical metal cleaning wastes generated and discharged by a generating unit do not meet all of these three criteria, then EPA proposes that the generating unit will not be eligible for the exemption. For example, if the plant currently hauls the nonchemical metal cleaning wastes off site for disposal, the generating units associated with the nonchemical metal cleaning waste generation would not be exempt. Any public comments submitted with the intention of identifying generating units that might appropriately fall within the exemption must provide the necessary documentation (e.g., permits, fact sheets) to support a finding that the generating unit meets all three criteria. EPA also requests comment on this general method of implementing the exemption. Another approach would be to define the conditions of the exemption, and then make it available to any facility that qualified, regardless of whether the facility was identified to EPA during the comment period. This would give EPA less information on the potential effects of including this exemption in the final rule, but would also allow qualified facilities to make use of the exemption even if they were unaware of the need to file comments during the comment period in order to make use of it. EPA requests comment on this, or any other, way of implementing the proposed exemption.

EPA is also considering setting BAT limitations equal to BPT limitations applicable to metal cleaning waste for all discharges of nonchemical metal cleaning wastes (i.e., not creating an exemption from copper and iron limits for discharges of nonchemical metal cleaning wastes from generating units currently authorized to discharge those wastes without copper and iron limits). As part of this approach, EPA is evaluating whether plants would incur costs to comply with the current BPT requirements applicable to discharge of metal cleaning wastes. Therefore, EPA is also soliciting comments that provide information on those generating units that are not currently subject to the BPT metal cleaning waste limitations for copper and iron, in order to understand what actions would be required to comply with the proposed BAT nonchemical metal cleaning waste limitations for iron and copper. EPA is

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particularly interested in the following information:

- Type of nonchemical metal cleaning waste generated, frequency of generation, and volume generated;
- Wastewater characterization data (i.e., monitoring data) for the nonchemical metal cleaning waste; [32]
- Information regarding the actions that would need to be taken to comply with the iron and copper limits for the nonchemical metal cleaning wastes discharged; and
- Estimated capital and operating and maintenance costs, broken out by specific cost components (e.g., equipment costs, installation costs, labor costs), to comply with the proposed copper and iron limits, along with the basis for the cost estimate.

EPA's analysis to date suggests that all four preferred options, Option 3a, Option 3b, Option 3, and Option 4a, are economically achievable. EPA performed cost and economic impact assessments using the Integrated Planning Model (IPM) for Option 3 and Option 4.[33] Option 4 is more costly than any of the four preferred options including Option 4a; therefore by performing the assessments with these two options, EPA can evaluate the potential effects of each of the preferred options. Because the costs and the facilities affected by Option 3a and 3b are a subset of Option 3, EPA can use the results of Option 3 to inform the potential impacts of Option 3a and Option 3b. In a similar way, because the costs and the facilities affected by Option 4a are a subset of Option 4, EPA can use the results of Option 4 to inform the potential impacts of Option 4a.

For the options analyzed overall, the model showed very small effects on the electricity market, on both a national and regional sub-market basis. Based on the results of these analyses, EPA estimates that the proposed requirements associated with Option 3a, Option 3b, and Option 3 would not lead to the premature retirement of any steam electric generating units (i.e., no partial or full plant closures).

The results for Option 4 show fourteen unit (partial) closures and zero plant (full) closures projected as of the model year 2030, reflecting full compliance of all facilities.[34] [35] The 14 generating units are located at six plants. The IPM results also show that five steam electric units that are projected to close under the base case (i.e., in the absence of the proposed revisions to the ELG) would remain operating under proposed Option 4 (i.e., avoiding closure). As a result, for Option 4, the IPM analysis projects total net closure of nine generating units, with total combined generating capacity of 317 MW. These results support EPA's conclusion that Option 4 is economically achievable. As explained above, because the costs and facilities affected by Option 4a are only a subset of Option 4 (i.e., are less than those for Option 4), the model would project similar or smaller effects for Option 4a. These IPM estimates for closures and avoided closures also support EPA's conclusion that Option 4a is economically achievable for the steam electric industry.

As part of its consideration of technological availability and economic achievability, EPA also considered the magnitude and complexity of process changes and new equipment installations that would be required at facilities to meet the requirements of the rule. As described in greater detail in Section XVI, EPA is proposing that, where the limitations and standards being proposed today for existing direct and indirect dischargers are more stringent than existing BPT requirements, those limitations and standards do not begin to apply until July 1, 2017 (approximately three years following promulgation of the final rule). EPA is proposing this approach to provide the time that many facilities will need to raise capital, plan and design systems, procure equipment, and construct and then test systems. Moreover, this approach will enable facilities to take advantage of planned shutdown or maintenance periods to install new pollution control technologies. EPA's proposal is designed to minimize any potential impacts on electricity availability caused by forced outages.

Options 3a, 3b, 3 and 4a have acceptable non-water quality environmental impacts, as discussed in Section XV of the preamble and in the TDD. EPA estimates that Options 3a, 3b, 3, and 4a would increase energy consumption by less than 0.003 percent, less than 0.004 percent, less than 0.008 percent, and less than 0.012 percent, respectively, of the total electricity generated by power plants. EPA also estimates that Options 3a, 3b, 3, and 4a would increase the amount of fuel consumed by increased operation of motor vehicles (e.g., for transporting fly ash) by less than 0.009 percent, less than 0.009 percent, less than 0.009 percent, and less than 0.014 percent, respectively, of total fuel consumption by all motor vehicles.

As discussed in Section XV.B., EPA also evaluated the effect of the proposed rule on air emissions generated by power plants ($NO_X$, sulfur oxides ($SO_X$), and $CO_2$). For Options 3a, 3b, and 3, the $NO_X$ emissions are estimated to increase by no more than 0.12 percent, and for Option 4a, by no more than 0.13 percent. EPA projects no significant increase in emissions of $SO_X$ or $CO_2$ under the four preferred options.

EPA also evaluated the effect of the proposed rule on solid waste generation and water usage. There would be no increase in solid waste generation under Option 3a, and EPA estimates that solid waste generation at power plants will increase by less than 0.001 percent under the other three preferred options. EPA estimates the power plants would reduce water use by 50 billion gallons per year (136 million gallons per day) under Option 3a, 52 billion gallons per year (143 million gallons per day) under Option 3b, 53 billion gallons per year (144 million gallons per day) under Option 3, and 103 billion gallons per year (282 million gallons per day) under Option 4a.

EPA also examined the effects of the preferred options on consumers as an "other factor" that might be appropriate when considering what level of control represents BAT. If all compliance costs were passed on to residential consumers of electricity instead of being borne by the operators and owners of power plants, the monthly increase in electricity bill would be no more than $0.04, $0.06, $0.13, and $0.22, respectively under Options 3a, 3b, 3, and 4a.

EPA is not proposing either Option 1 or Option 2 as its preferred option for BAT because neither option would represent the best available technology level of control for steam electric power plant discharges. For example, Options 1 and 2 would allow plants to continue

[32] Commenters should provide available monitoring data (i.e., EPA is not requiring the commenters to collect additional samples). Additionally, commenters should specify what data are represented by the characterization data (which wastestreams were sampled, the percent contribution of each wastestream, whether the samples are untreated or treated, and if treated, the type of treatment system represented).

[33] IPM is a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. See Section XI for additional discussion.

[34] As used here for the purpose of this rulemaking, the term partial closure refers to a plant where the closure of a generating unit is projected, but one or more generating units at the plant will continue operating. A full closure refers to a situation where all generating units at a plant are projected to shut down.

[35] Given the design of IPM, unit-level and thereby plant-level projections are presented as an indicator of overall regulatory impact rather than a prediction of future unit–level or plant-specific compliance actions.

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to discharge fly ash transport wastewater without treating the wastes to remove dissolved metals and many of the other pollutants present in the wastewater. However, 66 percent of all coal- and petroleum coke-fired generating units that produce fly ash as a residue of the combustion process already use dry fly ash technologies to manage all of their fly ash without any associated creation or discharge of fly ash transport water. And another 15 percent of the coal- and petroleum coke-fired generating units that produce fly ash also already operate dry fly ash handling systems in addition to a wet ash handling system (either as a completely redundant system, or to manage a fraction of the fly ash that is produced during combustion). Similarly, every generating unit operating a FGMC system does so in a manner that avoids creating any FGMC wastewater (92 percent of units with FGMC), or manages the FGMC wastewater in a closed cycle process that does not result in a discharge to surface water (8 percent of units with FGMC). The technology serving as the basis for FGD effluent limits under Option 1 is not effective at removing many of the pollutants of concern in FGD wastewater, including selenium, nitrogen compounds, and certain metals that contribute to high concentrations of total dissolved solids in FGD wastewater (e.g., bromides, boron). Furthermore, the information in the record for this proposed rule demonstrates that the amount of mercury, selenium, and other pollutants removed by the biological treatment stage of the treatment system, above and beyond the amount of pollutants removed in the chemical precipitation treatment stage preceding the bioreactor, can be substantial. Options 1 and 2 would remove fewer or similar levels of pollutants to the preferred options, all of which EPA believes, based on its analysis to date, to be technologically available, economically achievable, and have acceptable non-water quality environmental impacts. Options 1 and 2 would establish new effluent limits for three of the seven key wastestreams addressed in this rulemaking. For the remaining four wastestreams, BAT effluent limits would be set equal to the current BPT effluent limits.

EPA did not select Option 4 as its preferred regulatory option because of concerns expressed above associated with the projected compliance costs associated with zero discharge requirements for bottom ash for units equal to or below 400 MW. The bottom ash requirements for Option 4 and the preferred Option 4a are the same with the exception that Option 4a proposes to set the BAT effluent limits for bottom ash transport water equal to the current BPT effluent limits for units less than or equal to 400 MW, while Option 4 would set the BAT effluent limits for bottom ash transport water equal to the BPT effluent limits for units less than or equal to 50 MW. All other units would be subject to "zero discharge" effluent limits for all pollutants in bottom ash transport water.

Moreover, Option 4 proposes to establish BAT discharge limitations for toxic discharges for leachate. The record demonstrates that the amount of pollutants collectively discharged in leachate by steam electric plants is a very small portion of the pollutants discharged collectively for all steam electric power plants (i.e., less than ½ a percent). The technology basis for limitations on discharges of combustion residual leachate proposed under Option 4 is chemical precipitation. Because of the relatively low level of pollutants in this wastestream, and because EPA believes this is an area ripe for innovation and improved cost effectiveness, EPA is not putting forward this option as a preferred option. On balance, EPA would like to collect additional information on costs and effectiveness of chemical precipitation and other possible technologies for reducing pollutants discharged in leachate before making a finding with respect to what technologies represent the best available technology economically achievable for controlling discharges of pollutants found in combustion residual leachate. Consequently, EPA is interested in receiving information through the public-comment process related to cost, pollutant reduction, and effectiveness data on chemical precipitation and alternative approaches to treatment of combustion residual leachate.

EPA did not select Option 5 as its preferred option for BAT because of the high total industry cost for the option ($2.3 billion/year annualized social cost) and because of preliminary indications that Option 5 may not be economically achievable. While EPA has traditionally looked at affordability of the rule to the regulated industry, EPA has in some limited instances over the past three decades rejected an option primarily on the basis of total industry costs. See 48 FR 32462, 32468 (July 15, 1983) (Final Rule establishing ELGs for the Electroplating and Metal Finishing Point Source Categories); 74 FR 62996, 63026 (Dec. 1, 2009) (Final Rule establishing ELGs for the Construction and Development Point Source Category); *BP Exploration & Oil, Inc.* v. *EPA,* 66 F.3d 784, 796–97 (6th Cir. 1996) (upholding EPA's decision not to require zero discharge of produced waters based on reinjection for the Offshore subcategory of the Oil and Gas Extraction Point Source Category based in part on total industry cost). EPA similarly finds this appropriate here. In addition, certain screening-level economic impact analyses indicated that compliance costs may result in financial stress to some entities owning steam electric plants. Although EPA did not select Option 5 as the preferred BAT option, without question, Option 5 would remove the most pollutants from steam electric power plant discharges. Also, the technologies are all potentially available and may be appropriate (individually or in totality) as the basis for water quality-based effluent limits in NPDES permits, depending on site-specific conditions. For example, any of the requirements that would be established under Option 5, including at a minimum the vapor compression evaporation technology serving as the Option 5 technology basis for FGD wastewater, may be appropriate for those power plants that discharge upstream of drinking water treatment plants and that have bromide releases in wastewaters that impact treatment of source waters at the drinking water treatment plants. Section XIII of the preamble includes additional discussion about discharges of bromides. Also, see the EA.

For the reasons described below in Section VIII.B., EPA is proposing that, where the limitations and standards being proposed today are more stringent than existing BPT requirements, those limitations and standards do not begin to apply until July 1, 2017 (approximately three years from the effective date of this rule).

For all eight of the main BAT options under consideration, EPA is proposing to establish effluent limits for oil-fired generating units and small generating units (i.e., 50 MW or less) that differ from the effluent limits for all other generating units.[36] For oil-fired generating units and small generating units, EPA is proposing to set the BAT effluent limits equal to the current BPT effluent limits for all seven of the key wastestreams addressed by this proposed rule. For six of these wastestreams, BAT would be set equal to current BPT numeric limits for TSS

[36] For Option 4a, for discharges of pollutants found in bottom ash transport water only, as explained previously, EPA is proposing to raise the value from less than or equal to 50 MW to less than or equal to 400 MW.

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and oil and grease, with these pollutants regulated as indicator pollutants for the control of toxic and nonconventional pollutants. For nonchemical metal cleaning wastes, EPA is proposing to set BAT equal to the current BPT effluent limits for copper and iron in metal cleaning wastes [37], but would not establish BAT effluent limits for TSS and oil and grease (which are also currently regulated by BPT for metal cleaning wastes). EPA's proposal and reasoning is detailed below.

In addition, EPA has identified some differences among the options in terms of cost effectiveness. Section XII of this preamble describes EPA's cost-effectiveness analysis for the preferred regulatory options. EPA's analysis to date shows that the average cost effectiveness ($1981/TWPE) under Option 3a, 3b, 3, and 4a for existing direct dischargers is $27, $31, $44, and $57, respectively. This demonstrates that Option 3a is the most cost effective of the preferred options, Option 4a is the least cost effective of the preferred options, and Option 3 and Option 3b are between the two.

EPA also calculated the cost-effectiveness of particular controls for the wastestreams that would be controlled under the preferred options for existing direct dischargers.[38] The cost-effectiveness for zero discharge of fly ash transport and FGMC wastewater, as in Option 3a, is $27 per TWPE removed. The cost effectiveness of chemical precipitation alone is $70 per TWPE removed, while the cost effectiveness of chemical precipitation plus anaerobic biological treatment, which is included in all options except Option 3a, is $60 per TWPE removed. The cost effectiveness of zero discharge of bottom ash transport water for all units more than 50 MW is $107 per TWPE. In comparison, when this requirement is applied only to units more than 400 MW, as in Option 4a, the cost effectiveness value is $99 per TWPE removed.

Thus, the cost effectiveness for control of the various wastestreams included within the preferred options ranges from $27–$107 per TWPE in $1981; with zero discharge controls on fly ash transport wastewater being the most cost-effective, zero discharge controls on bottom ash transport wastewater being the least cost effective, and controls for FGD wastewater based on chemical precipitation in combination with anaerobic biological treatment between the two.

*Effluent Limits for Oil-fired Generating Units.* EPA is proposing to establish BAT limits equal to BPT for existing oil-fired units. For the purpose of the proposed BAT effluent limits, oil-fired generating units would be those that use oil as either the primary or secondary fuel and do not burn coal or petroleum coke. Units that use oil only during startup or for flame stabilization would not be considered oil-fired generating units. EPA is proposing to set BAT limits equal to BPT for existing oil-fired units because, in comparison to coal- and petroleum coke-fired units, oil-fired units generate substantially fewer pollutants, are generally older and operate less frequently, and in many cases are more susceptible to early retirement when faced with compliance costs attributable to the proposed ELGs.

The amount of ash generated at oil-fired units is a small fraction of the amount produced by coal-fired units. Coal-fired units generate hundreds or thousands of tons of ash each day, with some plants generating more than 1,500 tons per day of ash. In contrast, oil-fired units generate less than one ton of ash per day. This disparity is also apparent when comparing the ash tonnage to the amount of power generated, with coal-fired units producing nearly 300 times more ash than oil-fired units (0.04 tons per MW-hour on average for coal units; 0.000145 tons per MW-hour on average for oil units). The amount of pollutants discharged to surface waters is roughly correlated to the amount of ash wastewater discharged, thus oil-fired units discharge substantially less pollutants to surface waters than a coal-fired unit even when generating the same amount of electricity. EPA estimates that if BAT effluent limits for oil-fired units were set equal to either the proposed Option 3 or Option 4a limits for coal-fired units (≤50 MW), the total industry pollutant reductions attributable to the proposed rule would increase by less than one percent.

Oil-fired units are generally among the oldest steam electric units in the industry. Eighty-seven percent of the units are more than 25 years old. In fact, more than a quarter of the units began operation more than 50 years ago. Based on responses to the industry survey, only 20 percent of oil-fired units operate as baseload units; the rest are either cycling/intermediate units (45 percent) or peaking units (35 percent). These units also have notably low capacity utilization. While a quarter of the baseload units report capacity utilization greater than 75 percent, most baseload units (60 percent) report a capacity utilization of less than 25 percent. Eighty percent of the cycling/intermediate units and all peaking units also report capacity utilization less than 25 percent. Thirty-five percent of oil-fired units operated for more than six months in 2009; nearly half of the units operated for less than 30 days.

As shown above, oil-fired units are generally older and operate intermittently (i.e., they are peaking, cycling, or intermediate units). While these oil-fired units are capable of installing and operating the treatment technologies evaluated as part of this rulemaking, and the costs would be affordable for most of the plants, EPA believes that, due to the factors described here, companies may choose to shut down these oil-fired units instead of making new investments to comply with the rule. If these units shut down, it could reduce the flexibility that grid operators have during peak demand because there would be less reserve generating capacity to draw upon. But more importantly, maintaining a diverse fleet of generating units that includes a variety of fuel sources is vital to the nation's energy security. Because the supply/delivery network for oil is different from other fuel sources, maintaining the existence of oil-fired generating units helps ensure reliable electric power generation. Thus, the oil-fired generating units add substantially to electric grid reliability and the nation's energy security.

Based on responses to the industry survey, EPA estimates that less than 20 oil-fired units discharged fly ash or bottom ash transport water in 2009. At the same time, EPA notes that many oil-fired units operate infrequently, which could contribute to the relatively low numbers of units discharging ash-related wastewater. Should more widespread operation of oil units be required to meet demands of the electric grid, additional plants may find it necessary to discharge ash transport water. Because of the operating conditions unique to the existing fleet of oil-fired units and potential effects on the nation's electric power grid, a non-water quality environmental impact that EPA considers under Section 304(b) of the CWA, EPA believes it is appropriate to set BAT effluent limits for oil-fired equal to the current BPT limits.

*Effluent Limits for Small Generating Units.* EPA is proposing to establish

[37] As described earlier in this section, EPA is proposing to exempt from new BAT copper and iron limitations existing discharges of nonchemical metal cleaning wastes that are currently authorized under their existing NPDES permit without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits for low volume waste.

[38] While it is not included in the preferred options as a wastestream with additional controls, EPA also looked at the cost effectiveness of controlling leachate using chemical precipitation and this value would exceed $1,000 per TWPE removed.

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BAT effluent limits equal to BPT for existing small generating units, which would be defined as those units with a total nameplate generating capacity of 50 MW or less.[39] Small units are more likely to incur compliance costs that are disproportionately higher per amount of energy produced than those incurred by large units because they are not as able to take advantage of economies of scale. For example, the unit-level annualized cost for the proposed FGD wastewater treatment technology under Option 3 (chemical precipitation plus biological treatment) is approximately seven times more expensive on a dollar-per-megawatt basis for small generating units, relative to units larger than 50 MW. Similarly, the unit-level annualized cost to convert the fly ash handling system to dry technology (conveyance equipment and intermediate storage silos) is more than four times more expensive on a dollar-per-megawatt basis for small generating units, relative to units larger than 50 MW. For Option 4, bottom ash conversions are more than six times more expensive for small units, on a dollar-per-megawatt basis.

Moreover, the record demonstrates that the amount of pollutants collectively discharged by small generating units is a very small portion of the pollutants discharged collectively for all steam electric power plants (e.g., less than 1 percent under Option 3). As a result, setting BAT limits equal to BPT for existing steam electric generating units with a capacity of 50 MW or less will have little impact on the pollutant removals for the overall rule.

EPA considered establishing the size thresholds for small generating units at 25 MW because that threshold is already used for this industry sector in some regulatory contexts. For example, the Clean Air act defines an "electric utility generating unit" as "any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale." CAA Section 112(a)(8), 42 U.S.C. 7412(a)(8). The existing ELGs for the steam electric power generating point source category also include different effluent limitations for plants with total rated generating capacity of less than 25 MW. See 40 CFR 423.13(c)(1) and 423.15(i)(1).

EPA currently proposes a threshold of 50 MW[40] rather than 25 MW because the proposed 50 MW threshold would do more to alleviate potential impacts.[41] EPA recognizes that any attempt to establish a size threshold for generating units will be imperfect due to individual differences across units and firms. However, EPA believes that a threshold of 50 MW or less reasonably and effectively targets those generating units that should receive different treatment based on the considerations described above. EPA requests comment on the proposed 50 MW threshold applicable to discharges of the wastestreams described under each of the preferred options, and as well as other possible thresholds for small units.

4. Rationale for the Proposed Best Available Demonstrated Control/NSPS Technology

Section 306 of the CWA directs EPA to promulgate New Source Performance Standards, or NSPS, "for the control of the discharge of pollutants which reflects the greatest degree of effluent reduction which the Administrator determines to be achievable through application of the best available demonstrated control technology, processes, operating methods, or other alternatives, including, where practicable, a standard permitting no discharge of pollutants." Congress envisioned that new sources could meet tighter controls than existing sources because of the opportunity to incorporate the most efficient processes and treatment systems into the facility design. As a result, NSPS should represent the most stringent controls attainable through the application of the best available demonstrated control technology, or BADCT, for all pollutants (that is, conventional, nonconventional, and priority pollutants).

After considering all of the technology options described above in Section VII.B.2, EPA is proposing to establish NSPS based on the suite of technologies identified for Option 4 in Table VIII–1. Thus, the proposed NSPS would do the following:

- Establish numeric effluent limits for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater;
- Maintain the current "zero discharge" effluent limit for all pollutants in fly ash transport water, and establish new "zero discharge" effluent limits for all pollutants in bottom ash transport water and FGMC wastewater;
- Establish numeric effluent limits for mercury, arsenic, selenium, and TDS in discharges of gasification wastewater;
- Establish numeric effluent limits for TSS, oil and grease, copper, and iron in discharges of nonchemical metal cleaning wastes; and
- Establish numeric effluent limits for mercury and arsenic in discharges of leachate.

The record indicates that the proposed NSPS is technologically available and demonstrated. The technologies that serve as the basis for Option 4 are all available based on the performance of plants using components of the suite of technologies within the past decade. For example, approximately a third of plants that discharge FGD wastewater utilize chemical precipitation (in some cases, also using additional treatment steps). Five plants operate fixed-film anoxic/anaerobic biological treatment systems for the treatment of FGD wastewater and another operates a suspended growth biological treatment system that targets removal of selenium.[42] EPA is aware of industry concerns with the feasibility of biological treatment at some power plants. Specifically, industry has asserted that the efficacy of these systems is unpredictable, and is subject to temperature changes, high chloride concentrations, and high oxidation reduction potential in the absorber (that may kill the treatment bacteria). EPA's record to date does not support these assertions, but is interested in additional information that addresses these concerns. Moreover, approximately 50 coal-fired generating units were built within the last 20 years and most (83 percent) manage their bottom ash without using water to transport the ash and, as a result, do not discharge bottom ash transport water. The Option 4 technologies being proposed today represent current industry practice for gasification wastewater. Every IGCC power plant currently in operation uses vapor compression evaporation to treat the gasification wastewater, even when the wastewater is not discharged and is instead reused at the plant. In the case of FGMC wastewater, every plant currently using post-combustion sorbent injection (e.g., activated carbon injection) either handles the captured spent sorbent with a dry process or

[39] Preferred Option 4a would increase this threshold for purposes of discharges of pollutants in bottom ash transport water only, to 400 MW or less.

[40] For Option 4a, for bottom ash transport water only, as explained previously, EPA is proposing to raise the value from less than or equal to 50 MW to less than or equal to 400 MW.

[41] As discussed in Section XVII.C, the proposed 50 MW threshold also alleviates potential impacts which may be borne by small entities or municipalities.

[42] Four of the six operate the biological treatment systems in combination with chemical precipitation. Other power plants are considering installing the biological treatment technology to remove selenium, and at least one plant is moving forward with construction.

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manages the FGMC wastewater so that it is not discharged to surface waters (or has the capability to do so). For leachate, as discussed above in Section VI, chemical precipitation is a well-demonstrated technology for removing metals and other pollutants from a variety of industrial wastewater, including leachate from other landfills not located at power plants. It therefore represents the "greatest degree of effluent reduction . . . achievable" as that phrase is used in section 306 of the Clean Water Act.

The proposed NSPS for discharges of nonchemical metal cleaning waste are equal to the current BPT effluent limits that apply to discharges of these wastes from existing sources. As such, the proposed NSPS would be consistent with current industry practice for treating nonchemical metal cleaning waste and is based on the same technology that was used as the basis for the current NSPS for chemical metal cleaning waste. Based on responses to the industry survey, facilities typically treat both chemical and nonchemical metal cleaning waste in similar fashion.

The NSPS being proposed today also poses no barrier to entry. The cost to install technologies at new units are typically less than the cost to retrofit existing units. For example, the cost differential between BAT Options 3 and 4 for existing sources is mostly associated with retrofitting controls for bottom ash handling systems. For existing generating units, the effluent requirements considered under Option 4a for BAT would cause those plants with units greater than 400 MW that discharge bottom ash wastewater to either modify their processes to become a closed-loop wet sluicing system, or retrofit modifications such as replacing the bottom of boilers to accommodate mechanical drag chain systems. For new sources, however, Option 4 would not present plants with the same choice of retrofit versus modification of existing processes. This is because every new generating unit already has to install some type of bottom ash handling system as the unit is constructed. Establishing a zero discharge standard for pollutants in bottom ash transport water as part of the NSPS means that power plants will install a dry bottom ash handling system during construction instead of installing a wet-sluicing system. EPA estimates that over the past 20 years, more than 50 new coal-fired generating units were built and that most of these units (83 percent) installed dry bottom ash handling systems.

Moreover, as described above in Section XI, EPA assessed the possible impacts of Option 4 to new units by comparing the costs of the Option 4 technologies to the costs of a new generating unit and as part of its Integrated Planning Model analyses. In both cases, the results show that the incremental costs that would be imposed by Option 4 do not present a barrier to entry. EPA estimated that the compliance costs for a new unit (capital and O&M) represent at most 1.5 percent of the annualized cost of building and operating a new 1,300 MW coal-fired plant, with capital costs representing less than 1 percent of the overnight construction costs, and annual O&M costs representing less than 5 percent of the cost of operating a new plant. IPM results show no barrier to new generation capacity during the model years in which all existing plants must be in compliance as a result of the BAT/NSPS compliance scenario.

Finally, EPA has analyzed non-water quality environmental impacts associated with Option 4 for existing sources, and its analysis is relevant to the consideration of non-water quality environmental impacts associated with Option 4 for new sources. EPA's analysis demonstrates that the non-water quality environmental impacts associated with Option 4 for existing sources are acceptable. Given that there is nothing inherent about a new unit that would alter the analysis for such sources, EPA believes that the non-water quality environmental impacts associated with the proposed NSPS regulatory option are, likewise, acceptable.

In contrast to the best available technology economically achievable, or BAT, that EPA is proposing today for existing sources, the proposed NSPS would establish the same limits for oil-fired generating units and small generating units [43] that are being proposed for all other new sources. A key factor that affects compliance costs for existing sources is the need to retrofit new pollution controls to replace existing pollution controls. New sources do not trigger retrofit costs because the pollution controls (process operations or treatment technology) are installed at the time the new source is constructed. Thus, new sources are less likely than an existing source to experience financial stress by the cost of installing pollution controls, even if the pollution controls are identical. EPA requests comment on its proposal to establish the same NSPS for small generating units as for larger units.

EPA is not proposing regulatory Options 1 or 2, which would establish new effluent limits for only two of the seven key wastestreams addressed by this proposed rule, as its preferred option for NSPS. As explained above, neither of these two options represents the greatest degree of effluent reduction which the Administrator determines to be achievable through the best available demonstrated control technology.

EPA also did not select any of the preferred BAT regulatory Options (i.e., Options 3a, 3b, 3, or 4a) as its preferred option for NSPS because they would not control FGD wastewater (Option 3a and Option 3b for units at plants with a total wet-scrubbed capacity of less than 2,000 MW), bottom ash transport water (Option 3a, Option 3b, Option 3, and Option 4a for units less than or equal to 400 MW) or leachate discharges (Options 3a, 3b, 3, and 4a) and other, more effective, available technologies exist that do not present a barrier to entry and have acceptable non-water quality environmental impacts. EPA did not select preferred Option 3a for the same reasons it rejected Options 1 and 2. EPA did not select Options 3b, 3, or 4a because, under these regulatory options, NSPS effluent limits for bottom ash transport water for all or some portion of units and leachate would be set equal to the current BAT effluent limits on TSS and oil and grease, which are based on using surface impoundments.[44] The record demonstrates that zero discharge technologies are effective and available for managing bottom ash at new sources. Since these zero discharge technologies have been installed at 83 percent of coal-fired units built in the last 20 years, effluent standards based on surface impoundments do not represent Best Available Demonstrated Control Technology to control the discharge of pollutants in the bottom ash wastestream from new sources regardless of the unit size. In addition, the record demonstrates that chemical precipitation is a more effective technology than surface impoundments for controlling the pollutants present in leachate. For these reasons, Options 3b, 3 and 4a do not represent the best available demonstrated control technology to control the discharge of pollutants of concern from new sources.

EPA did not select Option 5 as its preferred option for NSPS because of its high costs, which are substantially higher than the costs for Option 4 and the other options evaluated for NSPS. See the TDD and RIA for more information about the estimated

[43] As a point of clarification, this similarly holds true for bottom ash limitations.

[44] This rationale similarly applies to Option 3a.

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compliance costs for the NSPS options. Also, see Section XI below. The cost differential between Options 4 and 5 is primarily due to the evaporation technology basis for controlling pollutants in FGD wastewater under Option 5.

Finally, EPA notes that Option 5 is comparable to Option 4 with respect to much of the anticipated pollutant removals, particularly the expected removals of arsenic, mercury, selenium and nitrogen. At the same time, Option 5 would control other pollutants in FGD wastewater that Options 1 through 4 do not effectively control, namely boron, bromides, and TDS. EPA is aware that bromide in wastewater discharges from steam electric power plants located upstream from a drinking water intake has been associated with the formation of trihalomethanes, also known as THMs, when it is exposed to disinfectant processes in water treatment plants. EPA recommends that permitting authorities consider the potential for bromide discharges to adversely impact drinking water intakes when determining whether additional water quality-based effluent limits may be warranted. Although EPA did not select Option 5 as the preferred NSPS option, the technologies forming the basis for Option 5 are all technologically available and may be appropriate (individually or in totality) as the basis for water quality-based effluent limits in individual or general permits depending on site-specific conditions. EPA requests comment on its selection of Option 4 instead of Option 5 as the basis for NSPS.

5. Rationale for the Proposed PSES Technology

Section 307(b), 33 U.S.C. 1317(b), of the Clean Water Act requires EPA to promulgate pretreatment standards for pollutants that are not susceptible to treatment by POTWs or which would interfere with the operation of POTWs. EPA looks at a number of factors in selecting the technology basis for pretreatment standards. For existing sources, these factors are generally the same as those considered in establishing BAT. However, unlike direct dischargers whose wastewater will receive no further treatment once it leaves the facility, indirect dischargers send their wastewater to POTWs for further treatment. As such, EPA must also determine that a pollutant is not susceptible to treatment at a POTW or would interfere with POTW operations.

Table VIII–3 summarizes the pass through analysis results for the BAT/NSPS pollutants for the various wastestreams and regulatory options. As shown in the table, all of the pollutants proposed for regulation under BAT/NSPS pass through.

TABLE VIII–3—SUMMARY OF PASS THROUGH ANALYSIS RESULTS

| Treatment option | Pollutant | Pass through? (Yes/No) |
|---|---|---|
| Chemical Precipitation for FGD Wastewater and/or Leachate | Arsenic | Yes. |
| | Mercury | Yes. |
| Biological (chemical precipitation followed by anoxic/anaerobic biological) for FGD Wastewater and/or Leachate. | Arsenic | Yes. |
| | Mercury | Yes. |
| | Nitrate Nitrite as N | Yes. |
| | Selenium | Yes. |
| Mechanical Vapor-Compression Evaporation for FGD Wastewater | Arsenic | Yes. |
| | Mercury | Yes. |
| | Selenium | Yes. |
| | TDS | Yes. |
| Mechanical Vapor-Compression Evaporation for IGCC Wastewater | Arsenic | Yes. |
| | Mercury | Yes. |
| | Selenium | Yes. |
| | TDS | Yes. |
| Nonchemical Metal Cleaning Wastes | Copper | Yes. |

For this proposal, EPA evaluated the same model technologies and regulatory options for PSES that it evaluated for BAT (described in Section VIII.A.2). These standards would apply to existing generating units that discharge wastewater to POTWs.

As explained above in Section III.B.5, in selecting the PSES technology basis, the Agency generally considers the same factors as it considers when setting BAT, including economic achievability. Typically, the result is that the PSES technology basis is the same as the BAT technology basis. This proposal is no exception. After considering all of the technology options described in Section VIII.A.2, as is the case for BAT, EPA is proposing four preferred alternatives for PSES (i.e., Options 3a, 3b, 3, and 4a).

With the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller), the proposed rule under Option 3a would:

- Establish a "zero discharge" effluent limit for all pollutants in fly ash transport water and FGMC wastewater;
- Establish numeric effluent limits for mercury, arsenic, selenium, and TDS in discharges of gasification wastewater;
- Establish numeric effluent limits for copper in discharges of nonchemical metal cleaning wastes;[45] and
- Establish BAT effluent limits for bottom ash transport water and leachate that are equal to the current BPT effluent limits for these discharges (i.e., numeric effluent limits for TSS and oil and grease).

With the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller), the proposed PSES under Option 3b would:

- Establish standards for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater for units located at plants with a total wet-scrubbed capacity of 2,000 MW;[46]
- Establish a "zero discharge" standard for all pollutants in fly ash transport water and FGMC wastewater;

[45] As described in Section VIII.A.3, EPA is proposing to exempt from new BAT copper and iron effluent limits existing discharges of nonchemical metal cleaning wastes that are currently authorized by an NPDES permit without iron and copper limits. This exemption also applies to any indirect discharges of nonchemical metal cleaning waste that are authorized without copper pretreatment standards. For such indirect discharges, the regulation would not specify PSES.

[46] Under Option 3b (for units located at plants with a total wet-scrubbed capacity of less than 2,000 MW), the regulations would not specify PSES for FGD wastewater, and POTWs would need to develop local limits to address the introduction of pollutants by steam electric power plants to the POTWs that cause pass through or interference, as specified in 40 CFR 403.5(c)(2).

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- Establish standards for copper in discharges of nonchemical metal cleaning wastes;[47] and
- Establish standards for mercury, arsenic, selenium and TDS in discharges of gasification wastewater.

Under the third preferred alternative for PSES (Option 3), in addition to the requirements described for Option 3b, the proposed rule would establish the same standards for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater as for Option 3b from units at all steam electric facilities, with the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller).

Under the fourth preferred alternative for PSES (Option 4a), the proposed rule would establish "zero discharge" effluent limits for all pollutants in bottom ash transport water for units greater than 400 MW. All other proposed Option 4a requirements are identical to the proposed Option 3 requirements.

EPA is putting forth Options 3a, 3b, 3, and 4a as the Agency's preferred PSES regulatory options in order to confirm its understanding of the pros and cons of these options through the public comment process and intends to evaluate this information and how it relates to the factors specified in the CWA. For the same reasons identified in Section VIII.A.3 above for BAT, EPA's analysis to date suggests that for indirect dischargers as well as direct dischargers, the Option 3a, Option 3b, Option 3, and Option 4a technologies are available and economically achievable, and that the other regulatory options (Options 1, 2, 4, and 5) do not reflect the criteria for PSES. In addition, EPA has determined that these standards will prevent pass-through of pollutants from POTWs into receiving streams and also help control contamination of POTW sludge. EPA also considered the non-water quality environmental impacts and found them to be acceptable, as described in Section XV. Furthermore, for the same reasons that apply to EPA's preferred BAT options and described in Section VIII.A.3, with the exception of numeric standards for copper in discharges of nonchemical metal cleaning wastes,[48] EPA is proposing not to subject discharges from oil-fired generating units and small generating units (i.e., 50 MW or smaller[49]) to POTWs to requirements based on Options 3a, 3b, 3, or Option 4a.

Finally, similar to EPA's preferred BAT options and for the reasons supporting those options, for certain wastestreams, EPA is proposing that any new PSES discharge standards would apply to discharges of the regulated wastewater generated after July 1, 2017. See discussion in Section XVI.

6. Rationale for the Proposed PSNS Technology

Section 307(c) of the CWA, 33 U.S.C. 1317(c), authorizes EPA to promulgate pretreatment standards for new sources (PSNS) at the same time it promulgates new source performance standards (NSPS). As is the case for PSES, PSNS are designed to prevent the discharge of any pollutant into a POTW that may interfere with, pass through, or may otherwise be incompatible with POTWs. In selecting the PSNS technology basis, the Agency generally considers the same factors it considers in establishing NSPS along with the results of a pass through analysis. As a result, EPA typically promulgates pretreatment standards for new sources based on best available demonstrated technology for new sources. *See National Ass'n of Metal Finishers* v. *EPA*, 719 F.2d 624, 634 (3rd Cir. 1983). The legislative history explains that Congress required simultaneous establishment of new source standards and pretreatment standards for new sources for two reasons. First, Congress wanted to ensure that any new source industrial user achieve the highest degree of internal effluent controls necessary to ensure that such user's contribution to the POTW would not cause a violation of the POTW's permit. Second, Congress wished to eliminate from the new user's discharge any pollutant that would pass through, interfere, or was otherwise incompatible with POTW operations.

For this proposal, EPA evaluated the same model technologies and regulatory options for PSNS that it evaluated for NSPS (described above in Section VIII.A.4). These standards would apply to new generating units or new facilities that discharge wastewater to POTWs. After considering all of the technology options described in Section VIII.A.2, as is the case for NSPS, EPA is proposing to establish PSNS based on the technologies specified in Option 4. The proposed PSNS would:

- Establish standards for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater;
- Maintain a "zero discharge" standard for all pollutants in fly ash transport water, and establish a zero discharge standard for bottom ash transport water and FGMC wastewater;
- Establish standards for mercury, arsenic, selenium and TDS in discharges of gasification wastewater;
- Establish standards for copper in discharges of nonchemical metal cleaning wastes; and
- Establish standards for mercury and arsenic in discharges of leachate.

For the same reasons identified for NSPS in Section VIII.A.4, EPA is proposing Option 4 as its preferred option because the technologies forming the basis for that option are available and demonstrated and will not pose a barrier to entry.[50] In addition, EPA has determined that these standards will prevent pass-through of pollutants from POTWs into receiving streams and also help control contamination of POTW sludge. EPA also considered the non-water quality environmental impacts associated with the preferred option and found them to be acceptable, as described in Section XV.

7. Consideration of Future FGD Installations on the Analyses for the ELG Rulemaking

As explained earlier, implementation of air pollution controls may create new wastewater streams at power plants. The analyses and the findings on economic achievability presented in this preamble reflect consideration of wastestreams generated by air pollution controls that will likely be in operation at plants at the time EPA takes final action on this rulemaking. However, EPA recognizes that some recently promulgated Clean Air Act requirements, along with state requirements or enforcement actions, may lead to additional air pollution controls (and resulting wastestreams) at existing plants beyond this date. In an effort to assess the economic achievability of the proposed rule in such cases, EPA also conducted a sensitivity analysis that forecasts future installations of air controls through 2020[51] and the associated costs of

[47] As described in Section VIII.A.3, EPA is proposing to exempt from new BAT copper and iron effluent limits existing discharges of nonchemical metal cleaning wastes that are currently authorized by an NPDES permit without iron and copper limits. This exemption also applies to any indirect discharges of nonchemical metal cleaning waste that are authorized without copper pretreatment standards. For such indirect discharges, the regulation would not specify PSES.

[48] EPA is proposing to exempt from new PSES copper standards for existing discharges of nonchemical metal cleaning wastes that are currently authorized. For these discharges, the regulation would not specify PSES.

[49] Preferred Option 4a would increase this threshold for purposes of discharges of pollutants in bottom ash transport water only, to 400 MW or less.

[50] For the same reasons discussed above in Section VIII for NSPS, EPA similarly determined the other regulatory options do not reflect PSNS.

[51] EPA considers that by forecasting future installations of controls out to the year 2020, the sensitivity analyses for this rulemaking reasonably reflect full implementation of air pollution controls

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complying with these proposed regulatory requirements for the wastewater that may result from the forecasted air control installations. The sensitivity analysis and results are described in more detail in DCN SE01989.

EPA has two primary data sources upon which to make its projections of future air control installations: 1) Integrated Planning Model estimates for the final MATS rule; [52] and 2) responses to EPA's steam electric industry survey. At the time EPA promulgated the MATS rule in 2011, it projected air pollution control retrofits using IPM (which also included projected retrofits for CSAPR). To support this rulemaking, EPA surveyed the industry about its plans for installing certain new air pollution controls at facilities through 2020. EPA has no reason to conclude that either the IPM FGD projections or the survey projections are more accurate than the other. In fact, both of these sources may overstate actual installations. Prior to MATS becoming final, many plant owners and operators assumed that wet scrubbers would be the only technology available to meet emissions limits for acid gases. As EPA gathered and published additional data on facility emission rates (which informed how the Agency set the standards), and as stakeholders researched and published additional information on the performance of less capital-intensive control technologies such as dry sorbent injection, it has become clear that many facilities will find it more cost-effective to forgo wet scrubbers in favor of other emission-reduction strategies. Furthermore, major economic variables such as electricity demand and natural gas prices have changed substantially since the prevailing market conditions in 2010, when respondents were answering the survey. For example, a facility originally indicating an expectation in the industry survey to install a wet scrubber by 2020 may now find itself no longer competitive in the updated marketplace with substantially lower natural gas prices and lower electricity demand growth than previously expected. Consequently, the facility may elect to retire and thereby neutralize the previously reported intent to scrub. Nevertheless, these two sources remain the best available information EPA has with which to estimate future conditions.

As a first step in conducting a sensitivity analysis, EPA compared the projections from the two sources described above. This comparison demonstrates that the IPM results for the MATS Policy Case and the ELG industry survey responses are consistent at the aggregate level. Furthermore, in very large part, both the survey and IPM identify the same generating units as being wet-scrubbed, either currently or in the future (the two sources are in agreement for approximately 94 percent of the wet-scrubbed units). The two sources also project similar wet-scrubbed capacities. In the very few cases where there are differences between the two sources, the differences are primarily due to the expected variation at a unit-level (e.g., IPM projects wet FGD at unit A and dry FGD at unit B, but instead the survey responses report wet FGD at unit B and dry FGD at unit A). Another difference between the MATS IPM estimates and the industry survey estimates is that, in a very few cases, the IPM results estimate that certain plants would retire (and therefore would not install wet scrubbers). In conducting the analyses for the ELG, EPA made the conservative assumption (i.e., one that would tend to overestimate cost, if anything) that a plant would still be in operation in 2020 unless the plant has formally announced its closure by 2014.

Because its goal in conducting this sensitivity analysis was to assess the economic achievability of the proposed ELG, even in light of possible future air controls, EPA developed a conservative upper bound estimate of future installations by combining the results of the two sources to develop its "future steam profile." In other words, EPA combined any source that reported or projected a wet FGD into one "future steam profile." This "future steam profile" is conservative because it reflects more wet FGDs than are anticipated to actually be installed; that is, by aggregating the survey and IPM forecast estimates it results in a total number of wet FGD systems and wet-scrubbed capacity that is greater than either of those individual sources. EPA then added costs associated with projected wastewater discharges from this future steam profile to comply with this proposal to the total costs it previously calculated for the existing universe. Based on the results of this conservative analysis, EPA finds that discharges from these additional air controls (which, if actually installed, would be due to various requirements including state rules, consent decrees, CSAPR/CAIR, and MATS) may increase the costs of this proposed rule by no more than 10 to 15 percent. See discussion in Section VII.A.7. Even if all of these additional costs were to come to fruition, which is unlikely since the "future steam profile" overestimates the number of new wet FGD systems that are anticipated, EPA finds that these additional costs are economically achievable.

EPA notes that subsequent to its analysis, the D.C. Circuit Court of Appeals vacated the CSAPR. EPA will continue to assess the potential impacts that changes to air pollution regulations may have on future installations of wet FGD systems. For the purpose of FGD wastewater analyses for this rulemaking, EPA has made a conservative assumption that all of the previously projected wet scrubber additions in the CSAPR-inclusive baseline (which also included MATS, state rules, consent decrees, etc.) would continue to be built, and that discharges from those additional wet scrubbers would therefore be subject to the proposed revisions to the ELGs.

8. Timing of New Requirements

As part of its consideration of technological availability and economic achievability, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at many existing facilities to meet the requirements of the rule. As discussed in Section VIII.A.2, EPA proposes that certain BAT limitations for existing sources being proposed today (those that would establish requirements more stringent than existing BPT requirements) would apply on a date determined by the permitting authority that is as soon as possible when the next permit is issued beginning July 1, 2017 (approximately three years from the effective date of this rule). This is true of the proposed limitations and standards based on any of the eight main regulatory options, including the preferred options, Option 3a, Option 3b, Option 3, or Option 4a.

EPA is proposing this approach for several practical reasons. While some facilities already have the necessary equipment and processes in place, or could do so relatively quickly, and may need little time before they are able to comply with the revised ELG requirements, not all will be able to do so. Some facilities will need time to raise the capital, plan and design the system, procure equipment, construct and then test the system. Moreover, providing a window of time will better enable facilities to install the pollution control technology during an otherwise

to comply with existing federal and state requirements.

[52] EPA IPM v.4.10 projections for units based on compliance with CSAPR, MATS, state rules, and enforcement actions including consent decrees.

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planned shutdown or maintenance period. In some cases, a facility must apply for permission to enter into such a period where they are producing no or less power.

During site visits, EPA found that most facilities need several years to plan, design, contract, and install major system modifications, especially if they are to be accomplished during planned maintenance periods to avoid causing forced outages. EPA recognizes that the proposed rule would require a significant amount of system design by engineering firms, equipment procurement from vendors, and installation by trained labor forces. EPA anticipates that changes to FGD wastewater treatment systems, fly ash system, bottom ash systems, and/or leachate treatment systems would constitute major system modifications requiring several years to accomplish for many plants. EPA identified certain technical and logistical issues at some facilities that may warrant additional time, such as coordinating ash system conversions for multiple generating units. In order to avoid any impacts on the consistency and reliability of power generation, outages at multiple facilities in one geographic area would need to be coordinated, which could also result in the need for more time.

EPA recognizes that permitting authorities have discretion with respect to when to reissue permits and can take into consideration the need to provide additional time to include BAT limits to prevent or minimize forced outages. Thus, in some cases, the new BAT requirements may as a practical matter be applied to a facility sometime after July 1, 2017. However, EPA judges that, under this proposed approach, all steam electric facilities will have the proposed BAT limitations applied to their permits no later than July 1, 2022, approximately 8 years from the date of promulgation of any final ELGs. For indirect discharges, except with respect to discharges of nonchemical metal cleaning waste, the proposed PSES requirements would apply by the date determined by the control authority that is as soon as possible beginning July 1, 2017, or approximately three years after promulgation of any final ELGs. EPA's record indicates it may not take that long for all facilities to meet the limitations and standards. Some plants may not require a major modification for one or more systems to be able to comply with new effluent limits and therefore would need less time. For example, some plants have installed dry fly ash handling systems that have capacity to handle all generated ash dry, yet they also maintain a wet ash handling system as a backup. The backup wet system is typically operated only a few days per year. According to the industry survey, plants such as these could quickly cease operation of the wet system, complying with a zero discharge requirement with relative ease.

EPA envisions that each facility subject to this proposal would study available technologies and operational measures, and subsequently install, incorporate and optimize the technology most appropriate for each site. EPA believes the proposed rule affords flexibility for a reasonable amount of time to conduct engineering studies, assess and select appropriate technologies, apply for necessary permits, complete construction, and optimize the technologies' performance. The permitting authority could establish any additional interim milestones, as appropriate, within these timelines.

## IX. Technology Costs and Pollutant Reductions

This section provides an overview of EPA's approach for estimating the compliance costs and pollutant reductions associated with the regulatory options discussed in this proposal. Sections 9 and 10 of the TDD provide a much more in depth discussion of these analyses.

EPA often estimates costs and pollutant loads on a per plant basis and then sums or otherwise escalates the plant-specific values to represent industry-wide compliance costs and pollutant reductions. Calculating costs and loads on a per plant basis allows EPA to account for differences in plant characteristics such as types of processes used, wastewaters generated and their flows/volumes and characteristics, and wastewater controls in place (e.g., BMPs and end-of-pipe treatment). EPA took this approach in estimating the compliance costs and pollutant reductions associated with this proposed rule.

EPA estimated the costs to steam electric power plants—whose primary business is electric power generation or related electric power services—of complying with the proposed ELGs. EPA evaluated the costs of this proposal on all plants currently subject to the existing ELGs. Some aspects of this proposal (e.g., applicability changes) would likely not lead to increased costs to complying facilities. Other aspects of this proposal would likely lead to increased costs to a subset of complying facilities. These facilities are generally those that generate and discharge the wastestreams for which EPA is proposing new limitations or standards. EPA reviewed the steam electric industry for all facilities that generate the specific types of wastewater streams for which EPA evaluated additional limitations or standards. The following describes the detailed costing and loadings evaluation EPA performed for these plants.

As discussed earlier in this preamble, EPA proposes to establish a separate set of requirements for existing oil-fired generating units and units with a capacity of 50 MW or less. For these units, EPA is proposing to establish BAT limitations that would be set equal to BPT limitations. Since this proposed rule would not establish additional control on discharges associated with these operations, there would be no incremental costs for these units to comply with the requirements of this proposed rule.[53]

For the aspects of these proposed regulatory options that include limitations and standards for additional pollutants, EPA estimated compliance costs and pollutant reductions from data collected through survey responses, site visits, sampling episodes, and from individual power plants and equipment vendors. EPA used this information to develop computerized cost and pollutant loadings models for each of the technologies that form the basis of the regulatory options. EPA used these models to calculate facility-specific compliance costs and pollutant reductions for all power plants that the information suggests may incur costs to comply with one or more proposed limitations or standards associated with the regulatory options.[54] [55] Therefore,

[53] EPA did estimate costs for these existing oil-fired generating units and small generating units to comply with the options considered in this rulemaking and has included those estimates in the docket for the proposed rule (see DCN SE01957, *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category*).

[54] Because EPA anticipates taking final action on this rulemaking in 2014, EPA did not include plants that are expected to retire by 2014 and plants that do not discharge any of the applicable wastestreams. Since this timeframe is approximately one year following the date of the proposed rule, EPA considers there to be sufficient certainty regarding plant/unit retirements or relevant major system modifications for it to be reasonable for EPA to take into account in the regulatory analyses for this rulemaking, Retirements and modifications occurring farther into the future than 2014 become more uncertain and subject to change; thus, EPA has considered such future changes, as appropriate, in sensitivity analyses for proposed rule. However, this approach can result in estimating compliance costs for generating units that companies have announced will retire, repower, or convert from wet to dry ash handling. Because of this, EPA is considering using alternative dates, such as 2022 which may better reflect the implementation timeframe for the ELG, for the baseline year for its analyses for the final rule.

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EPA's plant-specific cost and pollutant reduction estimates represent the incremental costs/pollutant reductions for a plant when its existing practices would not lead to compliance with the option being evaluated for the proposed rule. While plants would not be required to implement the specific technologies that form the basis for the proposed limitations and standards for each of the regulatory options, EPA calculated the cost and associated pollutant reductions for plants to implement these technologies to estimate the compliance costs and pollutant loading reductions associated with EPA's proposed rule.

EPA's cost estimates include two key cost components: Capital costs (one-time costs) and operating and maintenance (O&M) costs (which are incurred every year). Capital costs comprise the direct and indirect costs associated with the purchase, delivery, and installation of pollution control technologies. Capital cost elements are specific to the industry and commonly include purchased equipment and freight, equipment installation, buildings, land, site preparation, engineering costs, construction expenses, contractor's fees, and contingency. Annual O&M costs comprise all costs related to operating and maintaining the pollution control technologies or performing BMPs for a period of one year. O&M costs are also specific to the industry and commonly include costs associated with operating labor, maintenance labor, maintenance materials (routine replacement of equipment due to wear and tear), chemical purchase, energy requirements, residual disposal, and compliance monitoring. In some cases, the technology options may also result in recurring costs that are incurred less frequently than annually (e.g., 3-year recurring costs) or one-time costs other than capital investment (e.g., one-time engineering costs).

*A. Methodology for Estimating Plant-Specific Costs*

The limitations and standards associated with the regulatory options for this proposed rule address various wastestreams and, as such, consist of multiple technology bases (see Table IX–1). As a first step in estimating costs to control discharges associated with a particular generating unit at an existing steam electric power plant subject to this rulemaking (i.e., existing sources), EPA used the plant's survey response to determine if the wastestreams it discharges may be affected by the limitations and standards for the regulatory options considered in this rulemaking. Then, for each of the wastestreams that may be affected by an option, EPA reviewed the industry survey response, available sampling data, and industry long-term self-monitoring data to determine if the plant currently meets the performance level of the technology basis for the requirement of an option for that wastestream. A portion of the steam electric industry has already implemented processes or treatment technologies that serve as the basis for the regulatory options considered for the proposed rule; as a result, these facilities would not incur costs to comply with the proposed rule, or would incur costs lower than they would be if the processes/technologies had not already been implemented. In such cases, EPA assigned no compliance cost associated with the discharge of that particular wastestream other than compliance monitoring costs. For all other applicable wastestreams, EPA assessed the operations and treatment system components in place at the plant, identified necessary components that the plant would need to come into compliance, and estimated the cost to install and operate those components. Table IX–2 presents a list of the major cost components included in the evaluation. As appropriate, EPA also accounted for expected reductions in the plant's costs associated with their current operations or treatment systems that would no longer be needed as a result of installing and operating the technology bases (e.g., avoided costs to manage surface impoundments). For plants that may already have certain components installed, EPA compared certain key operating characteristics, such as chemical addition rates, to determine if additional costs (e.g., chemical costs) were warranted.

TABLE IX–1—TECHNOLOGY COST MODULES USED TO ESTIMATE COMPLIANCE COSTS

| Wastestream | Technology cost modules | Regulatory option | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 3a | 2 | 3b | 3 | 4a | 4 | 5 |
| FGD Wastewater | Chemical Precipitation | X | ..... | X | X | X | X | X | X |
| | Biological Treatment | ..... | ..... | X | X | X | X | X | |
| | Vapor-Compression Evaporation | ..... | ..... | ..... | ..... | ..... | ..... | ..... | X |
| Fly Ash Transport Water | Dry Fly Ash Handling | ..... | X | ..... | X | X | X | X | X |
| Bottom Ash Transport Water | Dry Bottom Ash Handling | ..... | ..... | ..... | ..... | ..... | X | X | X |
| Leachate | Chemical Precipitation | ..... | ..... | ..... | ..... | ..... | ..... | X | X |
| Gasification Wastewater | Vapor-Compression Evaporation | X | X | X | X | X | X | X | X |
| Flue Gas Mercury Control Wastes | Dry Handling | ..... | X | ..... | X | X | X | X | X |
| **Other Plant-Level Costs** | | | | | | | | | |
| | Solids Transportation | X | X | X | X | X | X | X | X |
| | Solids Disposal | X | X | X | X | X | X | X | X |
| | Impoundments | X | X | X | X | X | X | X | X |
| | Compliance Monitoring | X | X | X | X | X | X | X | X |

[55] EPA is considering establishing BMPs that would apply to surface impoundments that receive, store, dispose of, or are otherwise used to manage coal combustion residuals including FGD wastes, fly ash, bottom ash (which includes boiler slag), leachate, and other residuals associated with the combustion of coal to prevent uncontrolled discharges from these impoundments. Costs for the industry to implement the BMPs under consideration are included in EPA's cost and economic analyses for the proposed rule.

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TABLE IX–2—MAJOR CAPITAL COST COMPONENTS INCLUDED IN COMPLIANCE COSTS

| Technology module | Major capital cost components |
|---|---|
| Chemical Precipitation | • Equalization tank;<br>• Reaction tanks;<br>• Chemical feed systems;<br>• Solids contact clarifier;<br>• Sand filters;<br>• Treated wastewater tank;<br>• Sludge filter press; and<br>• Sludge holding tank. |
| Biological Treatment | • Bioreactor tanks;<br>• Nutrient feed system and storage;<br>• Backwash system and backwash wastewater tank; and<br>• Heat exchangers (if needed). |
| Vapor-Compression Evaporation | • Water softener;<br>• Brine concentrator; and<br>• Forced-circulation crystallizer. |
| Conversion of Wet Fly Ash Handling to Dry Vacuum Fly Ash Handling | • Conveyance Vacuum Line Components (i.e., valves, piping, couplings);<br>• Filter-Receiver;<br>• Vacuum Pumps;<br>• Lot miscellaneous instrumentation and control;<br>• Steel or concrete silo;<br>• Silo Instrumentation and Aeration System; and<br>• Pugmill unloaders. |
| Conversion of Wet Bottom Ash Handling to Mechanical Drag System (MDS) or Remote MDS. | • Water bath trough;<br>• Chain conveyor;<br>• Inclined conveyor;<br>• Storage silo;<br>• Remote MDS only: collection sump, chemical feed system, and recirculation pumps. |
| Transportation | • Only operating and maintenance cost components |
| Disposal | • On-Site Disposal:<br>• Landfill expansion construction<br>• Leachate treatment system<br>• Groundwater wells<br>• Closure cap<br>• Off-Site Disposal: no capital cost components |
| Compliance Monitoring | • Only operating and maintenance cost components |

For example, to comply with BAT regulatory Option 4 presented in this proposal, EPA estimated compliance costs for a plant that currently sluices fly ash to an ash impoundment and subsequently discharges that fly ash transport water. In this case, EPA estimated the cost for the plant to convert its fly ash handling system to a dry vacuum system and assumed that certain components of its existing system would continue to be used following the conversion.[56] EPA also included costs for additional equipment, such as vacuum systems and silos, to handle and store the dry fly ash. EPA also included additional transportation and landfill disposal costs and cost savings for managing less waste through the ash impoundment(s).

As another example, EPA estimated compliance costs to comply with BAT regulatory Option 4 for a plant that currently treats its FGD wastewater through a chemical precipitation system prior to discharge. In this case, EPA evaluated 1) whether the chemical precipitation system design basis included equalization with 24-hour residence time, 2) if the plant had an equivalent number and/or type of reaction tanks, and 3) if the plant already had components such as chemical feed systems, solids contact clarification, sand filtration, effluent and sludge holding tanks, sludge filter press, and pumps in place. If the plant had any of these components in place, EPA did not include that cost in its compliance cost estimate. EPA also evaluated whether chemical addition costs would be required based on the plant's reported chemical addition and dosages, and estimated the costs for installing and operating the biological treatment stage.

Following the evaluation of treatment in place, EPA estimated plant and wastestream specific incremental costs using computerized design and cost models. For the applicable wastestreams, the models provide capital, annual O&M, one-time, and 3-, 5-, 6-, and 10-year recurring costs for implementing and using the applicable technology basis. EPA developed cost equations from responses to the industry survey, published information, vendor contacts, and engineering judgment. EPA developed the following cost modules:

- One-Stage Chemical Precipitation—calculates capital and O&M costs associated with a one-stage chemical precipitation system;
- Biological Treatment—calculates capital and O&M costs associated with an anoxic/anaerobic biological treatment system;
- Vapor-Compression Evaporation—calculates capital and O&M costs associated with a vapor-compression evaporation system;
- Dry Fly Ash Handling—calculates capital, O&M, and recurring costs associated with a dry fly ash handling system;

[56] The conversion from wet to dry fly ash handling for a unit requires new equipment to pneumatically convey the ash; however, ash handling vendors stated that for dry vacuum retrofits, the existing hopper equipment and branch lines can be retained and reused.

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- Dry Bottom Ash Handling—calculates capital, O&M, and recurring costs associated with a dry bottom ash handling system;
- Transportation—calculates O&M costs associated with transporting FGD, ash, and/or landfill leachate solid waste to an on-site or off-site landfill;
- Disposal—calculates capital and O&M costs associated with disposing of FGD, ash, and/or landfill leachate solid waste in an on-site or off-site landfill; and
- Impoundment Costs—calculates capital, O&M, and recurring costs associated with the operation and maintenance of an on-site impoundment.

Ultimately, the cost model produces a plant-level summary of the incremental technology option costs associated with each regulatory option. Each plant incurring a cost for an evaluated wastestream is presented in the output. To determine the total compliance cost for a plant associated with a regulatory option, EPA calculated the various cost components described above for each applicable wastestream. EPA then summed the costs for each component of each wastestream to calculate the total capital, O&M, and other recurring costs for the plant. Section XI of this preamble and the RIA contains a more detailed discussion of EPA's annualization of the compliance costs.

EPA also evaluated the expected costs of compliance for new sources. The construction of new generating units may occur at an existing power plant or at a new plant construction site. The incremental cost associated with complying with the proposed NSPS and PSNS options will vary depending on the types of processes, wastestreams, and waste management systems that the plant would have installed in the absence of the proposed new source requirements. EPA estimated capital and O&M costs for several scenarios that represent the different types of operations that are present at existing units at existing power plants or are typically included at new power plants. These scenarios captured differences in the plant status (i.e., building a unit at a new location versus adding a new unit at an existing power plant), presence of on-site impoundments or landfills, type of ash handling, type of FGD systems in service, and type of leachate collection and handling.

Finally, EPA recognizes there are significant drivers including federal, state, and local requirements for future air control installations at existing units. As such, EPA also conducted a sensitivity analysis that forecasts future installations of air controls through 2020[57] and the associated costs of the regulatory options discussed in this proposal. EPA estimated these installations using data reported by individual plants in the survey regarding planned installations, as well as analyses conducted by OAR using the IPM, which is widely used by EPA for analysis of rules and policies affecting electric power generating facilities. Section VIII.A.7 contains a discussion of EPA's approach for forecasting future installations. EPA then estimated plant-specific costs for these future installations, using the same approach as it used for current operations.

*B. Methodology for Estimating Plant-Specific Pollutant Reductions*

EPA took a similar approach to the one described above for costs in estimating pollutant reductions associated with the limitations and standards for the regulatory options in this proposal. That is, EPA estimated incremental pollutant reductions for discharges of a particular wastestream at a particular plant when its existing practices would not lead to compliance with the option being evaluated. In such cases, EPA estimated the annual pollutant (baseline) load associated with the current discharge of a wastestream and the post-compliance annual pollutant load expected after implementation of the applicable technology basis. EPA then calculated the pollutant loading reduction at a particular plant as the sum of the difference between the estimated baseline and post-compliance discharge load for each applicable wastestream.

The following provides a brief discussion of the methodology EPA used to estimate baseline loads discharged for the various wastestreams. For those plants that discharge indirectly to POTWs, EPA adjusted the baseline loads to account for pollutant removals expected from POTWs. These adjusted pollutant reductions for indirect dischargers reflect reductions in discharges to receiving waters.

1. FGD Wastewater

For FGD discharges, EPA estimated baseline loadings by assigning pollutant concentrations based on the type of treatment system currently in place at the plant. EPA assigned treatment in place for this wastestream to one of four classes of treatment: surface impoundment, chemical precipitation, anaerobic/anoxic biological treatment, and vapor-compression evaporation. EPA identified the plant's current treatment system using data reported in the industry survey. Of the 117 plants that discharge FGD wastewater, 40 operate chemical precipitation systems, six operate biological treatment systems, and two operate a vapor-compression evaporation system.[58] All other plants are categorized in the surface impoundment class of treatment.

EPA then estimated the average baseline pollutant effluent concentration of each analyte for each class of treatment. EPA used data collected in its sampling program to characterize effluent concentrations from chemical precipitation, anoxic/anaerobic biological treatment, and vapor-compression evaporation systems. Because EPA lacked data on pollutant effluent concentrations associated with FGD wastewater impoundments, EPA estimated that surface impoundments remove particulate matter (including the particulate phase metals) to an equivalent treatment level of 30 mg/L TSS (i.e., thus assuming that the discharge would be in compliance with the current BPT effluent limits for low-volume waste sources). EPA estimated that all dissolved metals will pass through the surface impoundment and be discharged. Section 10 of the TDD contains more information on baseline pollutant effluent concentrations.

EPA then used this average baseline pollutant effluent concentration with plant-specific discharge flow rates reported in the industry survey to estimate the mass pollutant discharged per plant.[59] Section 9 of the TDD contains more details on how EPA developed flow rates.

For post-compliance FGD pollutant loading concentrations, for each pollutant, EPA used the long-term average for the technology basis for the option being evaluated. With a few exceptions, EPA then used these pollutant concentrations in combination with the same plant-specific discharge flow rates it used for baseline. The exceptions are five plants currently discharging FGD wastewater that EPA predicts will incorporate recycle within the FGD system based on the maximum operating chlorides concentration compared to the design maximum chlorides concentration.

[57] EPA expects that plants will be in compliance with new federal and state air pollution control requirements by 2020.

[58] A third power plant is currently installing a vapor-compression evaporation system to treat the FGD wastewater.

[59] In some cases, plant-specific discharge flow rates were not available in the survey response. See Section 9 of the TDD for more information on how EPA estimated flow rates.

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2. Fly Ash and Bottom Ash

For baseline ash loads, EPA used publicly available data to characterize discharges from ash impoundments, including data collected during EPA's Detailed Study, EPRI PISCES reports, permit application data, and the 1982 *Development Document for Final Effluent Limitations Guidelines, New Source Performance Standards, and Pretreatment Standards for the Steam Electric Point Source Category* (EPA 440–1–82–029). EPA used the concentration data obtained from these sources to calculate the average pollutant concentration in fly ash, bottom ash, and combined ash impoundments. EPA then coupled these concentrations with plant-specific ash sluice rates reported in the industry survey to calculate baseline ash discharge loads. In cases where EPA had available information regarding recycle associated with the impoundment overflow, EPA adjusted the sluice rates to reflect the discharge flow rate from the impoundment. For post-compliance pollutant loadings, EPA assumed implementation of dry ash handling would result in a zero post-compliance load.

3. Combustion Residual Leachate

For baseline leachate loads, EPA used data reported in Part G of the industry survey to calculate an average baseline pollutant concentration for leachate. These data included responses from 22 active fuel combustion residual landfills and four inactive fuel combustion residual landfills. EPA then used the baseline pollutant concentrations in conjunction with leachate flow rates to calculate the baseline pollutant loadings. Section 9 of the TDD describes how EPA used industry survey data to estimate leachate flow rates. For post-compliance leachate loads, EPA lacked data on effluent concentrations from chemical precipitation or biological treatment of leachate from combustion residual landfills or surface impoundments. EPA is proposing the effluent limits for leachate discharges would be based on transferring the effluent limits calculated for FGD wastewater using the identical technology bases. Therefore, EPA estimates, based on engineering judgment, that post-compliance effluent concentrations for leachate would be equal to the average effluent FGD wastewater concentrations for a similar treatment technology.

4. FGMC and Gasification Wastewaters and Nonchemical Metal Cleaning Wastes

FGMC wastewater originates from activated carbon injection systems. EPA identified 73 plants with current or planned activated carbon injection systems. Most of these plants use, or plan to use, a dry handling system to transfer the mercury-containing carbon to silos for temporary storage until the waste is hauled away by trucks for disposal in a landfill. EPA identified only six plants that transport (sluice) FGMC waste with water to a surface impoundment. However, five of these six plants do not discharge any FGMC wastewater and the remaining plant has the capability to handle the FGMC waste using a dry system but sometimes uses a wet system instead. Since the current baseline discharge of pollutants for FGMC wastewater is essentially zero, the proposed rule would establish effluent limitations that are consistent with the current industry practices for FGMC wastewater (i.e., zero discharge) and therefore EPA estimates there will be no (or little) incremental removal of pollutants relative to current practices. At the same time, however, establishing the proposed zero discharge standard for FGMC wastewater will ensure that future FGMC installations implement dry waste handling practices or manage wastewater in a manner that achieves zero discharge of pollutants.

The two IGCC plants currently operating in the United States already use the technology that is the basis for all eight regulatory options for gasification wastewater. A third IGCC plant that will soon begin commercial operation will also use this same treatment technology. Since these plants are already operating the technology that serves as the basis for the proposed BAT, the proposed rule would establish effluent limitations that are consistent with the current industry practices for gasification wastewater and, therefore, EPA estimates there will be no incremental removal of pollutants relative to current practices.

The proposed ELGs for discharges of nonchemical metal cleaning waste are equal to the current BPT effluent limits for metal cleaning waste. The proposed requirements are based on the same technology that was used as the basis for the current ELGs requirements for chemical metal cleaning waste. Since, as described above in Section VIII, nonchemical metal cleaning waste is included within the definition of metal cleaning waste, EPA would be establishing ELGs that are equal to the BPT limits that already apply to discharges of these wastes to surface waters.[60] Additionally, as described in Section VIII.A.3, EPA is proposing to exempt from new copper and iron limitations and standards any existing nonchemical metal cleaning wastes generated and currently authorized for discharge without copper and iron limits. As a result, all facilities are either already in compliance or will be exempt from the requirements; therefore, no facilities would incur incremental costs to comply with the proposed ELGs for these wastes, nor would there be incremental pollutant removals associated with the proposed ELGs.

5. Request for Comment on Data

While EPA is soliciting comment on all aspects of this proposal, the Agency would like to highlight certain aspects related to the pollutant removal estimates. EPA solicits additional data or information on pollutant loadings in steam electric power plant wastewater discharges that would corroborate or correct the data used in EPA's analysis, including data or information relating to the pollutants of concern that EPA has identified in this rulemaking. It is important that EPA have data and information of sufficient quality in order to incorporate the data into its analysis. If you have data or information or you intend to collect data that you believe would be relevant to EPA and you would like to submit the data as part of your public comments, EPA encourages you to contact the Agency first to ensure that the data submitted contains sufficient and relevant information, and that it is provided in an appropriate format, such that it can inform EPA's analyses for the final action (see points of contact in the introduction to this preamble).

EPA is also seeking comment related to the data used in developing this proposed rule and how it should be analyzed: age of data, treatment of non-detects, treatment of pollutants in the source water and the calculation of toxic-weighted pollutant equivalents.

Age of data. How should EPA take into account changes that may have occurred in the industry over time and what information would be appropriate for demonstrating that certain data for certain pollutants or wastestreams should or should not be used? For

[60] The proposed BAT would establish limits for copper and iron equal to the existing BPT limits for these pollutants. The proposed NSPS would establish standards for copper, iron, TSS, and oil and grease that are equal to the BPT limits for these pollutants. The proposed PSES and PSNS would establish standards for copper equal to the BPT limits for copper. See Section VIII for details about the proposed limitations for nonchemical metal cleaning wastes.

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example, should EPA use a date cutoff for the data used and what rationale should be used for any such cutoff? EPA encourages commenters to submit any more recent data (but you should contact EPA first to make sure the data you submit is usable for the analyses, see above).

Treatment of non-detect values. How should EPA treat non-detects in effluent data when determining baseline pollutant loadings? What other information should inform how EPA handles the issue of non-detects, given that in some cases, analytical methods cannot determine the actual amount of pollutants in wastewater? Should EPA use a cutoff for the number or percentage of non-detects in a dataset in order for EPA to use the dataset for a specific pollutant? For example, there were more non-detects than detected values for effluent data for sulfides. Does this dataset provide a sufficient basis, in the absence of any other information, for estimating pollutant loadings for sulfides?

Treatment of pollutants in the source water. When should EPA adjust pollutant loadings concentrations to account for contributions from a facility's source water? Should EPA estimate pollutant loadings for pollutants for which a certain percentage of the influent concentration comes from source water? If EPA were to do this, what steps should the Agency take to ensure the adjustments for source water contribution definitively link the source water data to the influent and effluent data?

Calculation of toxic-weighted pollutant equivalents. Is EPA's calculation of TWPEs appropriate? Do commenters have suggestions, either generally or relative to specific pollutants, for how this calculation can be improved?

### *C. Summary of National Engineering Costs and Pollutant Reductions for Existing Plants*

As described above in Section VIII, EPA evaluated eight regulatory options comprised of various combinations of the technology options considered for each wastestream, summarized in Table VIII–1. The Agency estimated the costs and pollutant loading reductions associated with steam electric power plants to achieve compliance with each regulatory option under consideration. This section summarizes the total estimated compliance costs and pollutant reductions associated with each option for existing plants (see Tables IX–3 and IX–4). These tables present the capital cost, annual operating and maintenance costs, one-time costs, and recurring costs for each regulatory option. Section XI contains a listing of total annualized costs by regulatory option. All cost estimates in this section are expressed in terms of pre-tax 2010 dollars. The costs shown in Section XI take into account the timeframe proposed to meet the limits in the rule.

Information, including plant-specific information, for EPA's compliance cost and pollutant loading estimates and methodologies is located in the rulemaking record. Some of the information EPA used to estimate compliance costs and pollutant loadings was claimed by survey respondents as CBI. Therefore, this information is not included in the public docket. However, the public docket contains a number of documents that set forth EPA's methodology, assumptions and rationale for developing its cost estimates and pollutant loadings estimates, and that also present as much data as possible by using aggregation, summaries, and other techniques to protect CBI. EPA encourages all interested parties to refer to the record and to provide comments where appropriate on any aspect of the methodology or the data used to estimate compliance costs and pollutant loadings associated with this proposal.

TABLE IX–3—COST OF IMPLEMENTATION (BAT AND PSES)

[In millions of pre-tax 2010 dollars]

| Regulatory option | Number of plants | Capital cost | Annual O&M cost | One time costs | Recurring costs | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | 3-year | 5-year | 6-year | 10-year |
| 1 | 116 | $1,450 | $194 | $0 | $0 | $0 | $10 | ($33) |
| 3a | 66 | 398 | 177 | 0 | 0 | 0 | 0 | (21) |
| 2 | 116 | 2,499 | 257 | 0 | 0 | 0 | 10 | (33) |
| 3b | 80 | 998 | 244 | 0 | 0 | 0 | 1 | (26) |
| 3 | 155 | 2,897 | 434 | 0 | 0 | 0 | 10 | (54) |
| 4a[a] | 200 | 5,478 | 689 | 0.3 | 1 | 38 | 10 | (90) |
| 4 | 277 | 8,011 | 988 | 0.6 | 28 | 65 | 16 | (137) |
| 5 | 277 | 11,755 | 1,753 | 0.6 | 28 | 65 | 19 | (137) |

[a] EPA estimated the costs for Option 4a based on approximated plant-level bottom ash costs for those plants that have at least one generating unit with a nameplate capacity of 400 MW or less and at least one other generating unit with a nameplate capacity of greater than 400 MW. For more details on how EPA estimated these plant-level bottom ash costs, see the memorandum entitled "Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Option 4a" (DCN SE03834).

TABLE IX–4—ESTIMATED POLLUTANT LOADING REDUCTION (BAT AND PSES)

[In million pounds/year]

| Regulatory option | Pollutant removals | | |
|---|---|---|---|
| | Conventional pollutants[a] | Priority pollutants | Nonconventional pollutants[b] |
| 1 | 2.8 | 0.5 | [c] (418) |
| 3a | 16 | 0.4 | 468 |
| 2 | 2.8 | 0.7 | 1,155 |
| 3b | 17.1 | 0.6 | 914 |
| 3 | 19 | 1.1 | 1,623 |
| 4a[d] | 28 | 1.4 | 2,612 |
| 4 | 35 | 1.7 | 3,328 |

TABLE IX–4—ESTIMATED POLLUTANT LOADING REDUCTION (BAT AND PSES)—Continued

[In million pounds/year]

| Regulatory option | Pollutant removals | | |
|---|---|---|---|
| | Conventional pollutants [a] | Priority pollutants | Nonconventional pollutants [b] |
| 5 | 36 | 1.7 | 5,287 |

[a] The loadings reduction for conventional pollutants includes BOD and TSS. Note that the BOD and TSS removals are not included in the total pollutant removals stated in Section II (1.63 billion pounds per year for Option 3; 3.34 billion pounds per year for Option 4) to avoid double-counting removals for certain priority and nonconventional pollutants that would also be measured by these bulk parameters.

[b] The loadings reduction for nonconventional pollutants excludes TDS and COD to avoid double-counting removals for certain pollutants that would also be measured by these bulk parameters (e.g., sodium, magnesium).

[c] Option 1 shows a negative removal for nonconventional pollutants because the mass of several pollutants (ammonia, chromium, TKN, and BOD) are not quantified at baseline, and because some pollutant discharge concentrations are higher under Option 1.

EPA estimated the pollutant removals for Option 4a based on approximated plant-level bottom ash loadings for those plants that have at least one generating unit with a nameplate capacity of 400 MW or less and at least one other generating unit with a nameplate capacity of greater than 400 MW. For more details on how EPA estimated these plant-level bottom ash loadings, see the memorandum entitled "Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Option 4a" (DCN SE03834).

## X. Approach To Determine Long-Term Averages, Variability Factors, and Effluent Limitations and Standards

This section describes the statistical methodology used to calculate the long-term averages, variability factors, and limitations for BAT, new source performance standards and pretreatment standards for existing and new sources. The effluent limitations and standards are based on long-term average effluent values and variability factors that account for variation in treatment performance of the model technology.

The proposed effluent limitations and/or standards, collectively referred to in the remainder of this section as "limitations," for pollutants for each technology option, as presented in this notice, are provided as "daily maximums" and "maximums for monthly averages." Definitions provided in 40 CFR 122.2 state that the daily maximum limitation is the "highest allowable 'daily discharge,'" and the maximum for monthly average limitation is the "highest allowable average of 'daily discharges' over a calendar month, calculated as the sum of all 'daily discharges' measured during a calendar month divided by the number of 'daily discharges' measured during that month." Daily discharges are defined to be the "'discharge of a pollutant' measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling." In this section, the term "option long-term average" and "option variability factor" are used to refer to the long-term averages and variability factors for technology options for an individual wastestream rather than the regulatory options described in Section VIII.

### *A. Criteria Used To Select Data as the Basis for the Limitations and Standards*

In developing effluent limitations guidelines and standards for any industry, EPA qualitatively reviews all the data before selecting data that represents proper operation of the technology that forms the basis for the limitations. EPA typically uses four criteria to assess the data. The first criterion requires that the plants have the model treatment technology and demonstrate consistently diligent and optimal operation. Application of this criterion typically eliminates any plant with treatment other than the model technology. EPA generally determines whether a plant meets this criterion based upon site visits, discussions with plant management, and/or comparison to the characteristics, operation, and performance of treatment systems at other plants. EPA often contacts plants to determine whether data submitted were representative of normal operating conditions for the plant and equipment. As a result of this review, EPA typically excludes the data in developing the limitations when the plant has not optimized the performance of its treatment system to the degree that represents the appropriate level of control (BAT or BADCT).

A second criterion generally requires that the influents and effluents from the treatment components represent typical wastewater from the industry, without incompatible wastewater from other sources. Application of this criterion results in EPA selecting those plants where the commingled wastewaters did not result in substantial dilution, unequalized slug loads resulting in frequent upsets and/or overloads, more concentrated wastewaters, or wastewaters with different types of pollutants than those generated by the wastestream for which EPA is proposing effluent limitations.

A third criterion typically ensures that the pollutants are present in the influent at sufficient concentrations to evaluate treatment effectiveness. To evaluate whether the data meet this criterion for inclusion as a basis of the limitations, EPA often uses the long-term average test (or LTA test) for plants where EPA possesses paired influent and effluent data (see Section 13 of the Technical Development Document for details of the LTA test). The test measures the influent concentrations to ensure a pollutant is present at a sufficient concentration to evaluate treatment effectiveness. If a dataset for a pollutant fails the test (i.e., pollutant not present at a treatable concentration), EPA excludes the data for that pollutant at that plant when calculating the limitations.

A fourth criterion typically requires that the data are valid and appropriate for their intended use (e.g., the data must be analyzed with a sufficiently-sensitive method). Also, EPA does not use data associated with periods of treatment upsets because these data would not reflect the performance from well-designed and well-operated treatment systems. In applying the fourth criterion, EPA may evaluate the pollutant concentrations, analytical methods and the associated quality control/quality assurance data, flow values, mass loading, plant logs, and other available information. As part of this evaluation, EPA reviews the process or treatment conditions that may have resulted in extreme values (high and low). As a consequence of this review, EPA may exclude data associated with certain time periods or other data outliers that reflect poor performance or

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analytical anomalies by an otherwise well-operated site.

The fourth criterion also is applied in EPA's review of data corresponding to the initial commissioning period for treatment systems. Most industries incur commissioning periods during the adjustment period associated with installing new treatment systems. During this acclimation and optimization process, the effluent concentration values tend to be highly variable with occasional extreme values (high and low). This occurs because the treatment system typically requires some "tuning" as the plant staff and equipment and chemical vendors work to determine the optimum chemical addition locations and dosages, vessel hydraulic residence times, internal treatment system recycle flows (e.g., filter backwash frequency, duration and flow rate, return flows between treatment system components), and other operational conditions including clarifier sludge wasting protocols. It may also take several weeks or months for treatment system operators to gain expertise on operating the new treatment system, which also contributes to treatment system variability during the commissioning period. After this initial adjustment period, the systems should operate at steady state with relatively low variability around a long-term average over many years. Because commissioning periods typically reflect one-time operating conditions unique to the first time the treatment system begins operation, EPA generally excludes such data in developing the limitations.[61]

### *B. Data Used as Basis of the Limitations and Standards*

The sections below discuss the data used as the basis for this proposal, including data selection, the combination of data from multiple sources within each plant, and the data exclusions made prior to calculate the limitations.

#### 1. Data Selection for Each Technology Option

This section describes the data selected for use in developing the limitations for each technology option. This section includes an abbreviated description of the technology options. See Section VIII for a more complete discussion of the technology basis for each of the options considered. For fly ash transport water and FGMC wastewater, all of the preferred regulatory options propose zero discharge of pollutants based on dry handling technologies; therefore, no effluent concentration data were used to set the limitations for these wastestreams. This is also true for the options that include zero discharge of pollutants for any set of dischargers for bottom ash.

Except as described in Section VIII, EPA is proposing to establish limitations for discharges of pollutants in nonchemical metal cleaning wastes that are equal to the current BPT limitations that apply to discharges of nonchemical metal cleaning wastes from existing sources that are direct dischargers. No new effluent concentration data were used to set the effluent limitations for nonchemical metal cleaning wastes in this rulemaking, therefore the limitations for this wastestream are not discussed in this section. See Section VIII for a more complete discussion of the basis for the proposed limitations.

Under some regulatory options being proposed today, EPA would establish limitations for certain wastewater discharges that are equal to the current BPT limitations for those discharges. No new effluent concentration data would be used to establish BAT/NSPS limitations that are set equal to BPT, therefore such limitations are not discussed in this section. See Section VIII for a more complete discussion of the basis for the proposed regulatory options. For the limitations for combustion residual leachate (hereafter referred to in this section as leachate) based on the chemical precipitation technology option, EPA is proposing to transfer the limitations calculated based on the chemical precipitation technology option for the FGD wastewater because EPA does not have the available effluent data for leachate from plants that employ the chemical precipitation technology. For the limitations based on the biological treatment technology option for FGD wastewater, EPA is proposing to transfer the limitations for two pollutants (mercury and arsenic) calculated based on the chemical precipitation technology option for the FGD wastewater for the reasons described below. See Section 13 of the Technical Development Document for a detailed discussion on the transfer of limitations for leachate and FGD wastewater.

EPA used specific data sources to derive limitations for pollutants in FGD and gasification wastewater discharges based on particular treatment technology. The data sources used to calculate limitations for each technology option, by wastestream, are described below.

#### a. FGD Wastewater

As part of the EPA sampling program and additional plant self-monitoring data EPA obtained during the rulemaking, EPA evaluated the performance of 10 FGD wastewater treatment systems. For seven of the 10 systems, EPA collected data representing the influent and effluent for chemical precipitation treatment systems. EPA evaluated these seven systems and determined that the systems operating the chemical precipitation system with both hydroxide and sulfide precipitation achieved better removals of mercury compared to the plants that used only hydroxide precipitation. Therefore, EPA did not use data from the three plants that use only hydroxide precipitation. Four of the seven plants use hydroxide and sulfide precipitation; however, one of the plants operates a two-stage chemical precipitation system. Because EPA's basis for the technology option is a one-stage system, EPA did not use the data from the two-stage system in developing the limitations.[62] Therefore, EPA used data from the following three plants to develop the limitations based on treatment of FGD wastewater using the chemical precipitation technology option (i.e., one-stage chemical precipitation system employing both hydroxide and sulfide precipitation and iron coprecipitation, as well as flow reduction at plants with large FGD wastewater flow rates, hereafter referred to in this section as "chemical precipitation"—see Section VIII above for a more detailed description):

[61] Examples of conditions that are typically unique to the initial commissioning period include operator unfamiliarity or inexperience with the system and how to optimize its performance; wastewater flow rates that differ significantly from engineering design, altering hydraulic residence times, chemical contact times, and/or clarifier overflow rates, and potentially causing large changes in planned chemical dosage rates or the need to substitute alternative chemical additives; equipment malfunctions; fluctuating wastewater flow rates or other dynamic conditions (i.e., not steady state operation); and initial purging of contaminants associated with installation of the treatment system, such as initial leaching from coatings, adhesives, and susceptible metal components. These conditions differ from those associated with the restart of an already-commissioned treatment system, such as may occur from a treatment system that has undergone either short or extended duration shutdown.

[62] Based on data EPA has evaluated for the steam electric industry and other industry sectors, two-stage chemical precipitation systems generally achieve better pollutant removals than one-stage systems. Since the technology basis for chemical precipitation treatment of FGD wastewater in the proposed rule is a one-stage system and that is the configuration used to estimate compliance costs, EPA concluded that effluent data for the two-stage system (Pleasant Prairie) should not be used when calculating effluent limits for the technology option.

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- Duke Energy's Miami Fort Station ("Miami Fort");
- RRI Energy's Keystone Generating Station ("Keystone"); and
- Allegheny Energy's Hatfield's Ferry Power Station ("Hatfield's Ferry").

For the treatment of FGD wastewater using a system that includes biological treatment as part of the process, EPA evaluated the treatment systems at three power plants as part of the EPA sampling program; however, one of the biological treatment systems was not designed for effective removal of selenium and does not represent the model technology. The biological treatment technology option is based on a one-stage chemical precipitation system employing both hydroxide and sulfide precipitation and iron coprecipitation, as well as flow reduction at plants with large FGD wastewater flow rates, followed by anoxic/anaerobic biological treatment designed to remove selenium, hereafter referred to in this section as "biological treatment"—see Section VIII above for a more detailed description. EPA used data from the following two plants to develop the limitations for the treatment of FGD wastewater using a one-stage chemical precipitation system followed by biological treatment:

- Duke Energy Carolina's Belews Creek Steam Station ("Belews Creek"); and
- Duke Energy Carolina's Allen Steam Station ("Allen").

While these two plants operate the biological treatment system included as the basis for the technology option, neither of these plants include sulfide precipitation in the upstream chemical precipitation system and rely only on hydroxide precipitation. Therefore, the effluent mercury and arsenic concentrations achieved by these plants do not fully represent the effluent concentrations that would be achieved by the system used as the design basis for the technology option. For this reason, EPA is proposing to establish the mercury and arsenic limitations for the biological treatment technology option (which includes one-stage chemical precipitation as an initial treatment stage) based on transferring the limitations that were calculated for the chemical precipitation treatment technology option. This is a reasonable approach for establishing mercury and arsenic limitations for the biological treatment technology option because, in doing so, EPA would be setting the limitations equal to the performance that reflects the level of treatment that would be achieved by the initial treatment stage of the wastewater treatment system.

For the treatment of FGD wastewater using a chemical precipitation followed by vapor-compression evaporation system hereafter referred to in this section as "vapor-compression evaporation" (which is the technology serving as the basis for regulatory Option 5, which is not a preferred option in this proposal), EPA evaluated three systems as part of the EPA sampling program. One plant operates a system that is similar to the technology basis for the FGD wastewater limitations in the proposed rule: A one-stage chemical precipitation system followed by softening and a vapor-compression evaporation system. EPA used the data from this plant to develop the limitations based on the vapor-compression evaporation technology for the treatment of the FGD wastewater. That plant is Enel's Federico II Power Plant, located in Brindisi, Italy. EPA used data from a second plant for characterization purposes and not for limitations development because it only collected effluent data for one day from the plant. The third system does not represent the technology serving as the basis for the vapor compression evaporation option, and thus was not used for the limitations development. This plant operates a solids removal process prior to the vapor-compression evaporation system but does not include a full chemical precipitation system nor a softening step. Furthermore, this plant also operates a one-stage evaporation system and instead of employing a second stage of evaporation to crystallize and remove salts and other pollutants from the concentration brine, mixes the brine with fly ash and sends it to the landfill for disposal.

b. Gasification Wastewater

For the treatment of gasification wastewater using a vapor-compression evaporation system, EPA evaluated systems from the following two plants as part of the EPA sampling program:

- Tampa Electric Company's Polk Station ("Polk"); and
- Wabash Valley Power Association's Wabash River Station ("Wabash River").

Both systems are representative of the system used as the basis for the technology option and were used in calculating the limitations.

2. Combining Data From Multiple Sources Within a Plant

Typically, if sampling data from a plant were collected over two or more distinct time periods, EPA analyzes the data from each time period separately. In previous effluent guidelines rulemakings, where appropriate, EPA has analyzed the data for each time period as if each time period represents a different plant since these data can represent different operating conditions due to changes in management, personnel, and procedures. On the other hand, when EPA obtains the data (such as EPA's sampling and plant self-monitoring data) from a plant during the same time period, EPA combines the data from these sources into a single dataset for the plant for the statistical analysis.

For this rulemaking, data at most selected plants came from multiple sources (EPA's sampling, plant sampling as directed by the EPA through 308 letters, or plant self-monitoring). For some plants, EPA has data collected from multiple sources during overlapping time periods. For these plants, EPA combined the multiple sources of data at each plant into a single dataset for the plant, which provided the basis for developing the limitations. Other plants had data collected from multiple sources during non-overlapping time periods. However, in these instances the time period between the non-overlapping data collection periods was relatively small (two months). Furthermore, EPA has no information to indicate that the data represent different operating conditions. Thus, EPA also combined the multiple sources of data for each of these plants into a single data set for the plant, which provided the basis for developing the limitations. Finally, a couple of plants had data from a single source, and for these plants it was not necessary to combine data. For a listing of all the data and their sampling sources for each of the plants, see DCN SE02002, "Sampling Data Used as the Basis for Effluent Limitations for the Steam Electric Rulemaking."

3. Data Exclusions

Following EPA's selection of the model plant(s), EPA applied the criteria described above in Section A by thoroughly evaluating all available data for each model plant. EPA identified certain data that warranted exclusions from the calculations of the limitations because: (i) The samples were analyzed using an insufficiently-sensitive analytical method (i.e., use of EPA Method 245.1 instead of Method 1631E for mercury); (ii) the samples were collected during the initial commissioning period for the treatment system; (iii) or analytical results were identified as questionable due to quality control issues, abnormal conditions or treatment upsets, or were analytical anomalies. See DCN SE01999 for a detailed discussion of the data excluded.

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*C. Overview of the Limitations and Standards*

The sections below describe EPA's objectives for proposing the daily maximum and monthly average limitations and the selection of percentiles for those limitations.

1. Objective

EPA's objective in establishing daily maximum limitations is to restrict the discharges on a daily basis at a level that is achievable for a plant that targets its treatment at the long-term average. EPA acknowledges that variability around the long-term average occurs during normal operations. This variability means that plants occasionally may discharge at a level that is higher (or lower) than the long-term average. To allow for these possibly higher daily discharges, EPA has established the daily maximum limitation. A plant that consistently discharges at a level near the daily maximum limitation would *not* be operating its treatment to achieve the long-term average. Targeting treatment to achieve the daily limitation, rather than the long-term average, may result in values that frequently exceed the limitations due to routine variability in treated effluent.

EPA's objective in establishing monthly average limitations is to provide an additional restriction to help ensure that plants target their average discharges to achieve the long-term average. The monthly average limitation requires dischargers to provide on-going control, on a monthly basis, that supplements controls imposed by the daily maximum limitation. In order to meet the monthly average limitation, a plant must counterbalance a value near the daily maximum limitation with one or more values well below the daily maximum limitation. To achieve compliance, these values must result in a monthly average value at or below the monthly average limitation.

2. Selection of Percentiles

EPA calculates limitations based upon percentiles that should be both high enough to accommodate reasonably anticipated variability within control of the plant, and low enough to reflect a level of performance consistent with the Clean Water Act requirement that these effluent limitations be based on the "best" available technologies. The daily maximum limitation is an estimate of the 99th percentile of the distribution of the *daily* measurements. The monthly average limitation is an estimate of the 95th percentile of the distribution of the *monthly* averages of the daily measurements. The percentiles for both types of limitations are estimated using the products of long-term averages and variability factors. EPA has consistently used the 99th percentile as the basis of the daily maximum limitation and 95th percentile as the basis of the monthly average limitation in establishing limitations for numerous industries and for many years and numerous courts have upheld EPA's approach.

EPA uses the 99th and 95th percentiles to draw a line at a definite point in the statistical distributions that would ensure that operators work to establish and maintain the appropriate level of control. These percentiles reflect a longstanding Agency policy judgment about where to draw the line. The development of the limitations takes into account the reasonable anticipated variability in discharges that may occur at a well-operated plant. By targeting its treatment at the long-term average, a well-operated plant should be capable of complying with the limitations at all times because EPA has incorporated an appropriate allowance for variability in the limitations.

In conjunction with setting the limitations as described above, EPA performs an engineering review to verify that the limitations are reasonable based upon the design and expected operation of the control technologies and the plant process conditions. As part of the review, for each plant EPA compared the influent and effluent measurements with the proposed effluent limitations. See Section F below for details of these comparisons for each pollutant at each plant, as well as a discussion of the findings of the engineering review.

*D. Calculation of the Limitations and Standards*

Effluent limitations and standards are based on a combination of the long-term average and the appropriate variability factors. In estimating the limitations for a pollutant, EPA first calculates an average performance level (the option long-term average discussed below) that a plant with well-designed and well-operated model technologies is capable of achieving. This long-term average is calculated using data from the plant or plants with the model technologies for the option.

In the second step of developing a limitation for a pollutant, EPA determines an allowance for the variation (the option variability factors discussed below) in pollutant concentrations for wastewater that has been processed through well-designed and well-operated treatment systems. This allowance for variation incorporates all components of variability including shipping, sampling, storage, and analytical variability. This allowance is incorporated into the limitations through the use of the variability factors, which are calculated from the data from the plants using the model technologies. If a plant operates its treatment system to meet the relevant long-term average, EPA expects the plant will be able to meet the limitations. Variability factors ensure that normal fluctuations in a plant's treatment are accounted for in the limitations. By accounting for these reasonable excursions above the long-term average, EPA's use of variability factors results in limitations that are generally well above the long-term averages.

The following sections describe the calculation of the option long-term averages, option variability factors and limitations, and adjustments for autocorrelation in calculating the limitations for each pollutant proposed for regulation.

1. Calculation of Option Long-Term Average

EPA calculated the option long-term average for a pollutant using two steps. First, EPA calculated the plant-specific long-term average for each pollutant that had enough distinct detected [63] values by fitting a statistical model to the daily effluent concentration values. In cases when a dataset for a specific pollutant did not have enough distinct detected values, then the statistical model was not used to obtain the plant-specific long-term average. In these cases, the plant-specific long-term average for each pollutant was the arithmetic mean of the available daily effluent concentration values. Appendix B of the Technical Development Document contains the required minimum number of distinct detected observations and an overview of the statistical model and a description of the procedures EPA used to estimate the plant-specific long-term average.

Second, EPA calculated the option long-term average for a pollutant as the *median* of the plant-specific long-term averages for that pollutant. The median is the midpoint of the values when ordered (i.e., ranked) from smallest to largest. If there is an odd number of values, then the value of the m*th* ordered observation is the median

[63] For the purpose of discussing the calculation of the long-term averages, variability factors, and effluent limitations, the term "detected" refers to analytical results measured and reported above the sample-specific quantitation limit. Thus, values described in this section as "non-detected" refers to values that are below the method detection limit (MDL) and those measured by the laboratory as being between the MDL and the quantitation limit (QL).

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(where m=(n+1)/2 and n=number of values). If there is an even number of values, then the median is the average of the two values in the n/2*th* and [(n/2)+1]*th* positions among the ordered observations.

2. Calculation of Option Variability Factors and Limitations

The following describes the calculations performed to obtain the option variability factors and limitations. First, EPA calculated the plant-specific variability factors for each pollutant that had enough distinct detected values by fitting a statistical model to the daily effluent concentration values. Each plant-specific daily variability factor for each pollutant is the estimated 99th percentile of the distribution of the daily pollutant concentration values divided by the plant-specific long-term average. Each plant-specific monthly variability factor for each pollutant is the estimated 95th percentile of the distribution of the 4-day average pollutant concentration values divided by the plant-specific long-term average. The calculation of the monthly variability factor assumes that the monthly averages are based on the pollutant being monitored weekly (approximately four times each month). In cases when there were not enough distinct detected values for a specific pollutant at a plant, then the statistical model was not used to obtain the plant-specific variability factors. In these cases, the data for the pollutant at the plant was excluded from the calculation of the option variability factors. Appendix B of the Technical Development Document contains the required minimum number of distinct detected observations and a description of the procedures used to estimate the plant-specific daily and monthly variability factors.

Second, EPA calculated the option variability factors. The option daily variability factor for a pollutant was found as the *mean* of the plant-specific daily variability factors for that pollutant. Similarly, the option monthly variability factor was the mean of the plant-specific monthly variability factors for that pollutant.

Finally, the daily limitation for each pollutant was the product of the option long-term average and option daily variability factor. The monthly average limitation for each pollutant was the product of the option long-term average and option monthly variability factor.

3. Adjustment for Autocorrelation Factors

Effluent concentrations that are collected over time may be autocorrelated. The data are positively autocorrelated when measurements taken at specific time intervals, such as one or two days apart, are similar. For example, positive autocorrelation would occur if the effluent concentration were relatively high one day and were likely to remain high on the next and possibly succeeding days. Because the autocorrelated data may affect the true variability of treatment performance EPA typically adjusts the variance estimates for the autocorrelated data, when appropriate. For this rulemaking, whenever there was sufficient data for a pollutant at a plant to evaluate the autocorrelation reliably, EPA estimated the autocorrelation and incorporated it into the calculation of the limitations. For a plant without enough data to reliably evaluate and obtain a reliable estimate of the autocorrelation, EPA set the autocorrelation to zero in calculation of the limitations. EPA did so because there were not sufficient data to reliably evaluate the autocorrelation, nor did EPA have a valid correlation estimate available that could be transferred from a similar technology and wastestream. See DCN SE02001 for details of the statistical methods and procedures used to determine the autocorrelation values, as well as a detailed discussion of the minimum number of observations needed to obtain a reliable estimate of the autocorrelation. Also, see Section 13 of the TDD.

*E. Long-Term Average, Variability Factors, and Limitations for Each Treatment Option*

Due to routine variability in treated effluent, a power plant that discharges consistently at a level near the values of the daily maximum limitation or the monthly average limitation may experience frequent values exceeding the limitations. For this reason, EPA recommends that power plants design and operate the treatment system to achieve the option long-term average for the model technology. Thus, a system that is designed to represent the BAT level of control will be capable of complying with the limitations. The table below provides the proposed long-term average, variability factors, and limitations for each of the FGD, gasification, and leachate treatment technology options. See DCN SE01999 for details of the calculation of the results presented in the table below.

TABLE X–1—PROPOSED LONG-TERM AVERAGES, VARIABILITY FACTORS, AND EFFLUENT LIMITATIONS FOR EACH OF THE FGD, GASIFICATION, AND LEACHATE TREATMENT TECHNOLOGY OPTIONS

| Treatment technology | Pollutant | Option LTA | Daily variability factor | Monthly variability factor | Daily limitation [d] | Monthly limitation [d] |
|---|---|---|---|---|---|---|
| Chemical Precipitation for FGD. | Arsenic (ug/L) | 4.483 | 1.741 | 1.223 | 8 | 6 |
| | Mercury (ng/L) | 75.404 | 3.209 | 1.570 | 242 | 119 |
| Chemical Precipitation and Biological Treatment for FGD. | Arsenic (ug/L)[a] | 4.483 | 1.741 | 1.223 | 8 | 6 |
| | Mercury (ng/L)[a] | 75.404 | 3.209 | 1.570 | 242 | 119 |
| | Nitrate-nitrite (mg/L) | 0.110 | 1.499 | 1.157 | 0.17 | 0.13 |
| | Selenium (ug/L) | 7.455 | 2.145 | 1.321 | 16 | 10 |
| Chemical Precipitation and Evaporation for FGD. | Arsenic (ug/L) | [b] 4.0 | (c) | (c) | [e] 4 | (f) |
| | Mercury (ng/L) | 17.788 | 2.192 | 1.338 | 39 | 24 |
| | Selenium (ug/L) | [b] 5.0 | (c) | (c) | 5 [e] | (f) |
| | TDS (mg/L) | 14.884 | 3.341 | 1.572 | 50 | 24 |
| Vapor-Compression Evaporation for Gasification. | Arsenic (ug/L) | [b] 4.0 | (c) | (c) | [e] 4 | (f) |
| | Mercury (ng/L) | 1.075 | 1.632 | 1.194 | 1.76 | 1.29 |
| | Selenium (ug/L) | 146.780 | 3.083 | 1.545 | 453 | 227 |
| | TDS (mg/L) | 15.209 | 2.483 | 1.389 | 38 | 22 |
| Chemical Precipitation for Leachate. | Arsenic (ug/L)[a] | 4.483 | 1.741 | 1.223 | 8 | 6 |
| | Mercury (ng/L)[a] | 75.404 | 3.209 | 1.570 | 242 | 119 |

[a] Option long-term average, option variability factors, and limitations were transferred from chemical precipitation treatment technology option.
[b] Long-term average is the arithmetic mean since all observations were non-detected.

[c] All observations were non-detected, so the variability factors could not be calculated.
[d] Limitations less than 1.0 are rounded up to the next highest hundredths decimal place. Limitations greater than 1.0 have been rounded upward to the next highest integer, except for limitations for mercury based on the vapor-compression evaporation treatment technology option for gasification wastewater which have been rounded up to the next highest hundredths decimal place.
[e] Limitation is set equal to the detection limit.
[f] Monthly average limitation is not established when the daily maximum limitation is based on the detection limit.

*F. Engineering Review of Limitations and Standards*

In conjunction with the statistical methods, EPA performed an engineering review to verify that the proposed limitations are reasonable based upon the design and expected operation of the control technologies. EPA performed two types of comparisons. First, EPA compared the limitations to the effluent data used to develop the limitations. Second, EPA compared the limitations to the influent data. Sections below summarize the results of these comparisons. For a detailed discussion of the results, see Section 13 of the Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD)—EPA 821–R–13.

1. Comparison of Limitations to Effluent Data Used As the Basis for the Limitations

As part of its data evaluations, EPA compared the limitations to the effluent values used to calculate the limitations. This type of comparison helps to evaluate how reasonable the proposed limitations may be from an engineering perspective. As part of this evaluation, for each pollutant proposed to be regulated under a technology option, EPA first compared the daily limitations to the daily effluent values. EPA then compared the monthly limitations to all the effluent daily values in a month, and identified those months where at least one value exceeded the monthly limitations.

After thoroughly evaluating the results of the comparison between the limitations and the effluent values used to calculate the limitations for each treatment technology option for FGD and gasification wastewaters, EPA determined that the statistical distributional assumptions used to develop the limitations are appropriate for the data, and thus the proposed limitations for each technology option are reasonable. (This conclusion is also true for the leachate limitations based on the chemical precipitation technology since the leachate limitations were transferred from the FGD wastewater technology option.) If a plant properly designs and operates its wastewater treatment system to achieve the option long-term average for the model technology (rather than targeting performance at the effluent limits themselves), it will be able to comply with the limitations.

However, EPA notes that some of the daily effluent values for the BAT plants used to calculate the limitations were found to exceed either the daily or monthly average effluent limitations. See Section 13.9.1 of the TDD for a detailed discussion of the comparison of the limitations and the effluent values, including a discussion of those effluent values that exceed the limitations. EPA solicits comment on this evaluation and EPA's conclusion that plants with a properly designed and operating treatment system would be able to comply with the limitations.

2. Comparison of the Limitations to Influent Data

In addition to comparing the proposed limitations to the data used to develop the limitations, EPA also compared the value of the proposed limitations to the influent concentration values. This comparison helps evaluate whether the proposed limitations are set at a level that ensures that treatment of the wastewater would be necessary to meet the limitations and that the influent concentrations were generally well-controlled by the treatment system. In doing so, EPA confirms that treatment to remove the regulated pollutants will take place.

For all treatment technology options for both FGD and gasification wastewater, the minimum, average, and maximum influent concentration values were much higher than the long-term average and proposed limitations (see DCN SE01999). Thus, EPA determined that facilities would need to treat the wastewater to ensure compliance with the proposed limitations and that the proposed rule would result in removing the regulated pollutants and other pollutants of concern. Furthermore, in evaluating influent concentrations, EPA found that influent concentrations were generally well-controlled by the treatment system for all plants with model technology. In general, the treatment systems adequately treated even the extreme influent values, and the high effluent values did not appear to be the result of high influent discharges.

EPA expects that facilities will comply with their effluent limitations at all times. If the exceedance is caused by an upset condition, the facility would have an affirmative defense to an enforcement action if the requirements of 40 CFR 122.41(n) are met. If an exceedance is caused by a design or operational deficiency, then EPA has determined that the facility's performance does not represent the appropriate level of control. For these proposed limitations, EPA has determined that such exceedances can be controlled by diligent process and wastewater treatment system operational practices such as frequent inspection and repair of equipment, use of back-up systems, and operator training and performance evaluations. Additionally, some facilities may need to upgrade or replace existing treatment systems to ensure that the treatment system is designed to achieve performance to target the effluent concentrations at the option long-term average. This is consistent with EPA's costing approach for the ELG technology options and its engineering judgment developed over years of evaluating wastewater treatment processes for power plants and other industrial sectors. EPA recognizes that, as a result of the proposed rule, some dischargers, including those that are operating technologies representing the "best available" technology, may need to improve their treatment systems, process controls, and/or treatment system operations in order to consistently meet the effluent limitations. EPA believes that this is consistent with the Clean Water Act, which requires that discharge limitations reflect the best available technology economically achievable or the best available demonstrated control technology.

## XI. Economic Impact and Social Cost Analysis

*A. Introduction*

EPA assessed the social costs and the projected economic impacts of the eight regulatory options described in this proposal (see Section VIII for a description of the options). This section provides an overview of the methodology EPA used to assess the social costs (or costs from the viewpoint of society rather than the regulated entity) and the economic impacts of the proposed ELGs and summarizes the results of these analyses. The Regulatory

Impact Analysis for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA)—EPA 821–R–13–005 and Benefits and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA)—EPA 821–R–13–004 reports available in the record for the rulemaking provide more details on these analyses, including discussion of uncertainties and limitations.

EPA estimated the costs to electric power producers—which include steam electric plants owned by investor-owned utilities, municipalities, states, federal authorities, cooperatives, and nonutilities, whose primary business is electric power generation or related electric power services—of complying with the proposed ELGs. As described in Section VI of this preamble, EPA estimated that 1,079 power plants operated at least one steam electric generating unit subject to the ELGs in 2009. EPA evaluated the costs and associated impacts of this proposal on these existing plants, and on new units that may be subject to the proposed revisions to the ELGs in the future. Plants that EPA estimates would incur compliance costs as a result of the proposed revisions to the ELGs are a subset of the 1,079 steam electric power plants.[64]

*B. Annualized Compliance Costs*

EPA's analyses of costs and economic impacts use the plant-level costs described in Section IX of this preamble. As described in that section, EPA developed plant-specific compliance costs for plants that generate a wastestream for which EPA evaluated new limitations and standards. Plant-specific compliance costs were developed for those plants for which EPA obtained detailed technical data through the industry survey. These costs consist of two principal components: initial planning and capital costs; and recurring operating and maintenance costs, which occur annually or according to a specified frequency (e.g., every 3 years, 5 years, 6 years, or 10 years). EPA applied survey weights to obtain costs for all 1,079 steam electric plants. Since all plants incurring non-zero costs have a sample weight of 1, the sum of costs for the surveyed plants also represents the total costs for the entire universe of 1,079 plants.

EPA restated compliance costs, accounting for the specific years in which each plant is assumed to undertake compliance-related activities and in 2010 dollars, using Construction Cost Index (CCI) from McGraw Hill Construction, the Employment Cost Index (ECI) published by the Bureau of Labor Statistics, and the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA). EPA used 2010 dollars based on data available at the time the analysis was developed. As a result, all dollar values reported in this analysis are in constant 2010 dollars.

EPA annualized the stream of future costs using 7 percent. The rate of 7 percent is used in the cost impact analysis as an estimate of the opportunity cost of capital.

EPA annualized one-time costs and costs recurring on other than an annual basis over a specific useful life, implementation, and/or event recurrence period, using a rate of 7 percent. For capital costs and initial one-time costs, EPA used 20 years. For O&M costs incurred at intervals greater than one year, EPA used the interval as the annualization period (i.e., 3 years, 5 years, 6 years, 10 years). EPA added annualized capital, initial one-time costs, and the non-annual portion of O&M costs to annual O&M costs to derive total annualized compliance costs, where all costs are expressed on an equivalent constantly recurring annual cost basis.

EPA uses pre- and/or after-tax compliance costs in different analyses, depending on the concept appropriate to each analysis (e.g., cost-to-revenue screening-level analyses discussed in Section XI.D are conducted using after-tax compliance costs, whereas social costs discussed in Section XI.C are calculated using pre-tax costs). For the assessment of compliance costs, EPA considered costs on both a pre-tax and after-tax basis. Pre-tax costs provide insight on the total expenditure as incurred. After-tax costs are a more meaningful measure of compliance impact on privately owned for-profit plants, and incorporate approximate capital depreciation and other relevant tax treatments in the analysis. EPA calculated the after-tax value of compliance costs by applying combined federal and State tax rates to the pre-tax cost values for privately owned for-profit plants. For this adjustment, EPA used State corporate rates from the Federation of Tax Administrators (*http://www.taxadmin.org/*) combined with federal corporate tax rate schedules from the Department of the Treasury, Internal Revenue Service.

Table XI–1 presents the total annualized compliance costs of the regulatory options on existing plants, estimated on a pre-tax and after-tax base. The table lists the eight options in order of increasing total annualized compliance costs. As shown in the table, after-tax annualized compliance costs range between $108.4 million and $1.55 billion for Options 3a and 5, respectively, with the preferred BAT and PSES options estimated to have annualized industry-wide after-tax costs of $108.4 million, $182.2 million, $389.0 million, $635.7 million (after-tax), respectively for Options3a, 3b, 3, and 4a. The costs shown in Table XI–1 do not reflect the compliance costs for new sources.

TABLE XI–1—TOTAL ANNUALIZED COMPLIANCE COSTS

[In millions, 2010$]

| 7% Discount rate | Pre-tax | After-tax |
|---|---|---|
| Option 3a | $168.1 | $108.4 |
| Option 3b | 264.6 | 182.2 |
| Option 1 | 265.9 | 190.6 |
| Option 2 | 393.3 | 280.6 |
| Option 3 | 561.3 | 389.0 |
| Option 4a | 947.8 | 635.7 |
| Option 4 | 1,373.2 | 916.9 |
| Option 5 | 2,277.3 | 1,547.9 |

The compliance costs above account for unit retirements, repowerings and conversions that have been announced by companies and are scheduled to occur by 2014, based on information obtained by EPA as of August 2012. But they do not reflect additional planned unit retirements, repowerings, and conversions that have been announced since August 2012, nor do they reflect announced retirements, repowerings, and conversions that are scheduled to occur by 2022. (See DCN SE02033, "Changes to Industry Profile for Steam Electric Generating Units Updates"). EPA estimates that accounting for these changes would reduce total annualized compliance costs. For example, EPA estimated that total pre-tax annualized compliance costs for Option 3 would go from $561.3 million to $532.8 million (5 percent reduction), whereas costs for Option 4 would go from $1,373.2 million to $1,252.9 million (9 percent reduction).

[64] As discussed in Section VIII, EPA is proposing different effluent limits for existing oil-fired generating units and units with a capacity of 50 MW or less. Because this proposed rule would set BAT equal to BPT limits, EPA accordingly did not estimate incremental costs for these units as a result of this proposed rule. Many plants are comprised of multiple units, and as such, there may be costs associated with some but not all units at a plant. The plants may incur costs for other, larger units, however, if any such units are also present; EPA's analysis includes costs for these larger units.

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*C. Social Costs*

Social costs are the costs of the rule from the viewpoint of society as a whole, rather than regulated facilities. In calculating social costs, EPA tabulated the pre-tax costs in the year when they are incurred. EPA assumed that all plants subject to the proposed regulation that would need to upgrade their systems would install control technologies over a five-year period beginning in 2017. This accounts for the time plants would have to implement control technologies, as described in Section XVI. For the purpose of the economic analyses, EPA assumed that plants would implement control technologies 3 years after the renewal of their individual NPDES permit, following the promulgation year, with NPDES permits assumed to be renewed on time, following a 5-year cycle.[65]

EPA performed the social cost analysis over a 24-year analysis period, which combines the length of the period during which plants are expected to install the control technologies (five-year period beginning in 2017) and the useful life of the longest-lived compliance technology installed at any facility (20 years). Under this framework, the last year for which costs (and benefits) were tallied in the analysis is 2040. EPA calculated social cost of the eight regulatory options for existing steam electric power plants using a 3 percent discount rate. EPA also calculated social costs using an alternative discount rate of 7 percent.[66] For the analysis of social costs, EPA discounted all costs to the beginning of 2014, which is the expected promulgation year for the proposed rule.

As described in Section XVII.B, EPA does not believe the proposed rule would lead to additional costs to permitting authorities. Consequently, the only category of costs necessary to calculate social costs are compliance costs; social costs differ from pre-tax compliance costs due to timing of costs and discounting using a societal discount rate.

Table XI–2 presents the total annualized social cost of the regulatory options on existing plants, calculated using 3 percent and 7 percent discount rates. The table lists the eight options in order of increasing total social costs calculated using a 3 percent discount rate.

TABLE XI–2—TOTAL ANNUALIZED SOCIAL COSTS

[In millions, 2010$]

| Regulatory option | 3% Discount rate | 7% Discount rate |
|---|---|---|
| Option 3a ..... | $185.2 | $164.5 |
| Option 1 ..... | 268.3 | 259.2 |
| Option 3b ..... | 281.4 | 257.2 |
| Option 2 ..... | 386.8 | 380.8 |
| Option 3 ..... | 572.0 | 545.3 |
| Option 4a ..... | 954.1 | 914.7 |
| Option 4 ..... | 1,381.2 | 1,323.2 |
| Option 5 ..... | 2,328.8 | 2,209.4 |

At 3 percent discount rate, total annualized social costs for existing plants vary from $185.2 million under Option 3a to $2.3 billion under Option 5, with the preferred BAT and PSES options having total annualized social costs of $185.2 million, $281.4 million, $572.0 million, and $954.1 million, respectively for Options 3a, 3b, 3 and 4a. The values presented in Table XI–2 for the 7 percent discount rate are slightly lower than the comparable values (pre-tax) presented in Table XI–1 due to the timing of compliance expenditures (e.g., $545.3 million versus $561.3 million, for Option 3).

These social costs do not reflect anticipated unit retirements and conversions anticipated through 2024. As noted in the previous Section, EPA anticipates that these changes would reduce total compliance costs incurred by the Steam Electric power industry, and therefore reduce the social costs of this action.

*D. Economic Impacts*

EPA assessed the economic impacts of the regulatory options in two ways: (1) A screening-level assessment of the impact of compliance costs on existing plants and the entities that own those plants, based on comparison of compliance costs to plant and entity revenue; and (2) an assessment of the impact of the proposed regulatory options for both existing and new plants within the context of the broader electricity market, which includes an assessment of incremental plant closures attributable to the proposed ELGs. EPA used the results of the screening-level assessment to inform the selection of regulatory options to be analyzed using the second approach.

The following sections summarize the methods and findings for these analyses.

1. Screening-Level Assessment of Impacts on Existing Plants and Parent Entities Incurring Compliance Costs Associated With This Proposed Rule

EPA conducted a screening-level analysis of the rule's potential impact to existing steam electric plants and parent entities based on cost-to-revenue ratios. For each of the two levels of analysis (plant and parent entity), the Agency assumed, for analytic convenience and as a worst-case scenario, that none of the compliance costs would be passed onto consumers through electricity rate increases and would instead be absorbed by complying plants and their parent entities. In performing these and other impact analyses, EPA used the survey weights to extrapolate impacts assessed initially for a sample of plants to all 1,079 steam electric plants and to their respective owning parent entities.

a. Cost-to-Revenue Analysis for Plants Incurring Compliance Costs Associated with this Proposed Rule

EPA calculated the annualized after-tax compliance costs of the regulatory options as a percent of baseline annual revenues.[67] Revenue estimates used in this analysis were developed using Energy Information Administration (EIA) data. (See Chapter 4 of the RIA report for a more detailed discussion of the methodology used for the plant-level cost-to-revenue analysis).[68]

Table XI–3 summarizes the screening-level plant-level cost-to-revenue analysis results for the eight main regulatory options. EPA estimates that the vast majority of plants subject to the proposed ELGs will incur annualized costs amounting to less than 1 percent of revenue for all eight regulatory options (887 to 1,051 plants, or 82 to 97 percent of the total 1,079 steam electric plants). A significant share of these plants incur no compliance costs. For the preferred BAT and PSES options (Options 3a, 3b, 3 and 4a), 92 percent to 97 percent of steam electric plants have estimated costs that are less than 1 percent of revenue. The number of plants with ratios between 1 percent and 3 percent, and above 3 percent,

[65] These assumed technology installation years do not necessarily correspond to the actual years in which individual facilities would be required to meet the effluent limits or standards as specified in their permit, but is a reasonable distribution of installation years for the aggregate set of steam electric plants incurring compliance costs. These assumptions reflect the approximate years in which technology installation would reasonably be expected to occur, assuming that expiring permits are renewed exactly on the 5-year mark. Note that EPA also analyzed the effects of other technology installation periods. The results of these analyses are detailed in Appendix B of the RIA report.

[66] These discount rate values follow guidance from the Office of Management and Budget (OMB) regulatory analysis guidance document, Circular A–4 (OMB, 2003).

[67] For private, tax-paying entities, *after-tax costs* are a more relevant measure of potential cost burden than *pre-tax costs*. For non tax-paying entities (e.g., State government and municipality owners of affected plants), the estimated costs used in this calculation include no adjustment for taxes.

[68] To develop the average of year-by-year revenue values over the data years, EPA set aside from the averaging calculation, revenue values for years that are substantially lower than the otherwise "steady state average"—e.g., because of a generating unit being out of service for an extended period.

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generally rises when moving from Option 3a to Option 5. For the preferred BAT and PSES options (Options 3a, 3b, 3 and 4a), two to six percent of plants have cost-to-revenue ratios between 1 and 3 percent and less than one percent to two percent have ratios above 3 percent.

TABLE XI–3—PLANT-LEVEL COST-TO-REVENUE ANALYSIS RESULTS BY REGULATORY OPTION [a]

| Option | No data on revenue [b] | Number of plants with cost-to-revenue ratio of | | | |
|---|---|---|---|---|---|
| | | 0% | 0–1% | 1–3% | >3% |
| Option 3a | 5 | 1,008 | 43 | 22 | 1 |
| Option 3b | 5 | 994 | 54 | 24 | 2 |
| Option 1 | 5 | 959 | 93 | 17 | 5 |
| Option 2 | 5 | 959 | 86 | 18 | 11 |
| Option 3 | 5 | 920 | 102 | 38 | 14 |
| Option 4a | 5 | 875 | 114 | 65 | 20 |
| Option 4 | 5 | 798 | 111 | 117 | 48 |
| Option 5 | 5 | 798 | 89 | 115 | 72 |

[a] This analysis makes a counterfactual, conservative assumption of zero cost pass-through. Plant counts are weighted estimates.
[b] EIA does not report necessary data to estimate revenue for 5 plants.

b. Parent Entity-Level Cost-to-Revenue Analysis

EPA also assessed the economic impact of the eight regulatory options at the parent entity-level. The screening-level cost-to-revenue analysis at the parent entity level provides insight on the impact of compliance requirements on those entities that own more than one plant incurring compliance costs associated with this proposed rule. For this analysis, EPA identified the domestic parent entity of each plant and obtained the entity's revenue from the industry survey or from publicly available data sources. In this analysis, the domestic parent entity associated with any given plant is defined as that entity that has the largest ownership share in the plant.

For each parent entity, EPA compared the total annualized after-tax compliance costs, as of 2014, and the identified parent entity's total revenue (see Chapter 4 of the RIA report for details). The total parent-level annualized after-tax compliance costs represent total costs for all steam electric plants in which the entity is the majority owner.

Compliance costs for the regulatory options were developed based on surveyed plants (see Section XI.D.1.a). For the parent entity-level analysis, EPA considered two approximate bounding cases to analyze the owners of all 1,079 steam electric plants, based on the survey weights developed from the industry survey. These cases, which are described in more detail in Chapter 4 of the RIA, provide a range of estimates for the number of entities incurring compliance costs and the costs incurred by any entity owning a steam electric plant.

Table XI–4 summarizes the results of the entity-level analysis for the two analytic cases and the eight regulatory options.

TABLE XI–4—PARENT ENTITY-LEVEL AFTER-TAX ANNUAL COMPLIANCE COSTS AS A PERCENTAGE OF REVENUE [a]

| Option | Total number of entities | Not analyzed due to lack of revenue information | | Number and percentage with after tax annual compliance costs/annual revenue of: | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 0% | | 0–1% | | 1–3% | | 3% or Greater | |
| | | # | % | # | % | # | % | # | % | # | % |
| **Case 1: Lower-bound estimate of number of entities owning steam electric plants; upper bound estimate of total compliance costs that an entity may incur** | | | | | | | | | | | |
| Option 3a | 243 | 14 | 6 | 205 | 84 | 22 | 9 | 2 | 1 | 0 | 0 |
| Option 3b | 243 | 14 | 6 | 201 | 83 | 26 | 11 | 2 | 1 | 0 | 0 |
| Option 1 | 243 | 14 | 6 | 173 | 71 | 51 | 21 | 1 | <1 | 4 | 2 |
| Option 2 | 243 | 14 | 6 | 173 | 71 | 46 | 19 | 6 | 2 | 4 | 2 |
| Option 3 | 243 | 14 | 6 | 168 | 69 | 49 | 20 | 7 | 3 | 5 | 2 |
| Option 4a | 243 | 14 | 6 | 157 | 65 | 55 | 23 | 11 | 5 | 6 | 2 |
| Option 4 | 243 | 14 | 6 | 137 | 56 | 64 | 26 | 21 | 9 | 7 | 3 |
| Option 5 | 243 | 14 | 6 | 137 | 56 | 57 | 23 | 20 | 8 | 15 | 6 |
| **Case 2: Upper-bound estimate of number of entities owning steam electric plants; lower bound estimate of total compliance costs that an entity may incur** | | | | | | | | | | | |
| Option 3a | 507 | 30 | 6 | 453 | 89 | 22 | 4 | 2 | <1 | 0 | 0 |
| Option 3b | 507 | 30 | 6 | 449 | 89 | 26 | 5 | 2 | <1 | 0 | 0 |
| Option 1 | 507 | 30 | 6 | 421 | 83 | 51 | 10 | 1 | <1 | 4 | 1 |
| Option 2 | 507 | 30 | 6 | 421 | 83 | 46 | 9 | 6 | 1 | 4 | 1 |
| Option 3 | 507 | 30 | 6 | 416 | 82 | 49 | 10 | 7 | 1 | 5 | 1 |
| Option 4a | 507 | 30 | 6 | 405 | 80 | 55 | 11 | 11 | 2 | 6 | 1 |
| Option 4 | 507 | 30 | 6 | 385 | 76 | 64 | 13 | 21 | 4 | 7 | 1 |
| Option 5 | 507 | 30 | 6 | 385 | 76 | 57 | 11 | 20 | 4 | 15 | 3 |

# equals the number of entities.

[a] This analysis makes a counterfactual, conservative assumption of zero cost pass-through.

The cost-to-revenue ratios provide screening-level indicators of potential economic impacts. Entities incurring costs below 1 percent of revenue are unlikely to face economic impacts, while entities with costs between 1 percent and 3 percent of revenue have a higher chance of facing economic impacts, and entities incurring costs above 3 percent of revenue have a still higher probability of economic impacts. As presented in Table XI–4, EPA estimated that the number of entities owning steam electric plants ranges from 243 (lower bound estimate) to 507 (upper bound estimate), depending on the assumed ownership structure of plants not surveyed. Under the lower-bound case, EPA estimates that the vast majority of parent entities will incur annualized costs of less than 1 percent of revenues under all eight analyzed regulatory Options (the shares are 93, 93, 89, and 87 percent under Options 3a, 3 and 4a, respectively). These observations also hold true under the upper bound case; an estimated 94, 94, 92, and 91 percent of parent entities incur annualized costs of less than 1 percent of revenue, for Options 3a, 3b, 3 and 4a, respectively.

Overall, this screening-level analysis shows that the entity-level compliance costs are low in comparison to the entity-level revenues; very few entities are likely to face economic impacts at any level for any of the four preferred BAT and PSES options (Options 3a, 3b, 3 and 4a).

2. Assessment of the Impacts in the Context of Electricity Markets

In analyzing the impacts of regulatory actions affecting the electric power sector, EPA has used the Integrated Planning Model (IPM), a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. The model is designed to evaluate the effects of changes in production costs at the level of the individual generating unit, on the total cost of electricity supply, subject to specified demand and emissions constraints. To assess facility and market-level effects of these proposed ELGs, EPA used an updated version of this same analytic system: Integrated Planning Model Version 4.10 MATS (IPM V4.10).

Use of a comprehensive, market analysis system is important in assessing the potential impact of the regulatory options because of the interdependence of electricity generating units in supplying power to the electric transmission grid. Increases in electricity production costs at some plants can have a range of broader market impacts affecting other plants, including the likelihood that various plants are dispatched, on average.

IPM V4.10 provides outputs for the North American Electric Reliability Corporation (NERC) regions that lie within the continental United States. IPM V4.10 does not analyze electric power operations in Alaska and Hawaii because these states' electric power operations are not connected to the continental U.S. power grid. However, none of the steam electric plants that are estimated to incur compliance costs associated with this proposal are located in these two regions.

IPM V4.10 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 EIA 860 (2006) and EIA 767 (2005) databases.[69] The IPM baseline universe of plants includes nearly all of the steam electric plants that could be subject to the proposed ELGs and are estimated to incur compliance costs.[70] IPM Version 4.10 embeds a baseline energy demand forecast that is derived from DOE's *Annual Energy Outlook 2010* (AEO2010). IPM V4.10 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)[71]; 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, 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 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 proposed ELGs. IPM is also dynamic in that it is capable of using forecasts of future conditions to make decisions for the present. Additionally, in contrast to the screening-level analyses in which EPA assumed no pass through of compliance costs, IPM depicts production activity in wholesale electricity markets where some recovery of compliance costs through increased electricity prices is possible but not guaranteed.

In performing analyses based on IPM V4.10, EPA used as its baseline—i.e., reflecting the world without this proposed regulation—a projection of electricity markets and facility operations over the period from the expected promulgation year, 2014, through 2030. As discussed above, this baseline accounts for compliance with the recently promulgated federal air rules.

As discussed in greater detail in Appendix C of the RIA, IPM generates least-cost resource dispatch decisions based on user-specified constraints such as environmental, demand, and other operational constraints. In analyzing the proposed ELGs, EPA specified additional fixed and variable costs that are expected to be incurred by specific steam electric plants and generating units to comply with the proposed ELGs. EPA then ran IPM including these additional costs to determine the dispatch of electricity generating units that would meet projected demand at

[69] In some instances, plant information has been updated to reflect known material changes in a plant's generating capacity since 2006.

[70] The IPM plant universe excludes two steam electric plants estimated to incur compliance costs under the proposed ELG scenarios EPA analyzed in IPM. See Chapter 5 of the RIA report for more details.

[71] 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 does not believe it would 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 a minimal effect on the results of the analysis conducted in support of the proposed ELGs.

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the lowest costs, subject to the same constraints as those present in the analysis baseline. The least-cost dispatch solution for meeting electricity supply may change as the result of the changes in fixed and variable costs at the level of the individual plant and generating unit, which EPA estimates would occur as a result of the proposed ELGs. These estimated changes in plant- and unit-specific production levels and costs—and, in turn, changes in total electric power sector costs and production profile—are key data elements in evaluating the expected national and regional effects of the proposed ELGs.

EPA used the screening-level analyses described above to inform the selection of regulatory options to be analyzed using IPM. In allocating resources to analytical effort, EPA chose to run IPM in a phased approach, starting with Option 3 and then Option 4, with the notion to proceed if additional model runs were warranted.

EPA first analyzed a scenario developed based on Option 3 but where the total compliance costs and the set of existing plants that are assigned costs varied slightly from those in the Option 3 discussed in other parts of this preamble.[72] Thus, the Option 3 scenario analyzed using IPM and discussed below did not include small changes to the timing of some O&M costs and to the set of plants assigned compliance costs for this option. Because of these changes and the need to protect data claimed as CBI by plant owners, total compliance costs for Option 3 as analyzed in IPM are approximately 10 percent lower than for the proposed Option 3 discussed in the rest of this document. EPA also analyzed a scenario in IPM that corresponds to BAT and PSES Option 4 discussed elsewhere in this notice.[73] Both scenarios analyzed in IPM included NSPS and PSNS compliance costs for new coal generation, based on the preferred Option 4 for new sources.

The two scenarios analyzed in IPM provide insight on the market impacts of the regulatory options EPA considered for this proposal. Options 3 and 4 as analyzed in IPM are similar enough to these proposed Options 3 and 4 to provide valuable insight on the likely impacts of the proposed ELGs. Options 3a, 1, 2, and 3b are less stringent than either of the two other options analyzed in IPM; as discussed further below, the relatively small impacts observed when analyzing the Option 3 scenario suggest that the impacts of Options 3a, 1, 2 and 3b would be less than Option 3. EPA did not analyze Option 4a due to time and resource constraints, but expects that this option could have impacts between those of Options 3 and 4. EPA did not analyze Option 5 based on screening-level analysis results, which showed that compliance costs could result in financial stress to some entities owning steam electric plants. As shown in Section XI.D.1, under Option 5, about three times as many entities owning steam electric plants would incur costs that exceed 3 percent of revenue than under Options 3 (15 versus 5 entities). Twice as many entities owning steam electric power plants are estimated to incur costs that exceed 3 percent of revenue under Option 5, when compared to Option 4 (15 versus 7 entities). As discussed in Section XVII.C, the potential cost impacts to small entities are also greater under Option 5 than under Options 3 and 4.

The IPM V4.10 runs provide analysis results for selected run-years: 2020 and 2030. These analysis years, each of which represents multiple years, take into account the expected promulgation year for these proposed ELGs (2014) and the years in which all plants would be expected to install compliance technology (five-year period beginning in 2017). In the following sections, EPA reports results for the run-year 2030, which represents years 2025–2034, by which time all plants subject to this rulemaking will meet the revised guidelines and standards and all compliance costs will be reflected in production costs (i.e., steady state of post-compliance operations). EPA considered impact metrics of interest at three levels of aggregation: (1) Impact on national and regional electricity markets (i.e., all electric power generation, including steam and non-steam plants), (2) impact on steam electric power generating plants as a group (i.e., the 1,079 plants subject to the proposed ELGs, not all of which are projected to incur compliance costs), and (3) impact on individual steam electric plants incurring compliance costs.

All results presented below are representative of modeled market conditions in the years 2025–2034. While costs are in 2010 dollars, they are reflective of costs in the modeled years and are not discounted to the start of EPA's analysis period of 2014.[74]

a. Impact on National and Regional Electricity Markets

For the assessment of market level electricity impacts, EPA considered five output metrics from IPM V4.10: (1) Incremental early retirements and capacity closures, calculated as the difference between capacity under the regulatory options and capacity under the baseline, which includes both full plant closures and partial plant closures (i.e., unit closures) in aggregate capacity terms; (2) incremental capacity closures as a percentage of baseline capacity; (3) post-compliance changes in variable production costs per MWh, calculated as the sum of total fuel and variable O&M costs divided by net generation; (4) changes in annual costs (fuel, variable O&M, fixed O&M, and capital); and (5) post-compliance changes in energy price, where electricity prices are defined as the wholesale prices received by plants for the sale of electricity they generate.

Table XI–5 presents results for the two market model analysis scenarios. The table provides the baseline capacity and the values of each of the five metrics above, with national totals and detail at level of regional electricity markets defined on the basis of the eight NERC regions defined in IPM.

Additional results are presented in Chapter 5 of the RIA report. Chapter 5 also presents a more detailed interpretation of the results of the market-level analysis.

[72] The costs as analyzed in IPM differ slightly from those used in the non-IPM analyses. For more details on these differences, see Chapter 5 of the RIA report. Note that the scenario assigns compliance costs for existing plants based on Option 3, and compliance costs for new capacity projected in IPM based on Option 4.

[73] Compliance costs differ only slightly (1 percent lower) from costs used in other analyses, primarily to avoid disclosing CBI. There are no differences in the set of plants estimated to incur compliance costs or in the timing of the costs. For more details, see Chapter 5 of the RIA report.

[74] In contrast, the social cost estimated in Section XI.C reflects the discounted value of compliance costs over the entire 24-year period of analysis, as of 2014. 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 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 proposed ELG.

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TABLE XI–5—IMPACT OF MARKET MODEL ANALYSIS OPTIONS ON NATIONAL AND REGIONAL MARKETS AT THE YEAR 2030

| NERC region | Baseline capacity (GW) | Incremental early retirements/closures [a] | | Change in variable production cost (2010$/MWh or % of baseline) | | Change in annual costs (million 2010$ or % of baseline) | | Change in electricity price (2010$/MWh or % of baseline) | |
|---|---|---|---|---|---|---|---|---|---|
| | | Capacity (GW) | % of Baseline closures | | | | | | |
| Option 3: | | | | | | | | | |
| ERCOT | 98 | 0 | 0.0 | $0.11 | 0.3% | $72 | 0.4% | $0.21 | 0.3% |
| FRCC | 68 | 0 | 0.0 | 0.14 | 0.3 | 49 | 0.3 | 0.23 | 0.3 |
| MRO | 76 | 0 | 0.0 | 0.02 | 0.1 | 53 | 0.4 | 0.03 | 0.1 |
| NPCC | 73 | 0 | 0.0 | 0.06 | 0.2 | 15 | 0.1 | 0.19 | 0.3 |
| RFC | 237 | 0 | 0.0 | 0.12 | 0.5 | 276 | 0.5 | 0.19 | 0.3 |
| SERC | 274 | 0 | 0.0 | 0.17 | 0.6 | 322 | 0.6 | 0.24 | 0.4 |
| SPP | 59 | 0 | −0.7 | 0.08 | 0.3 | 35 | 0.3 | 0.17 | 0.3 |
| WECC | 220 | 0 | 0.0 | 0.05 | 0.2 | 50 | 0.1 | 0.15 | 0.2 |
| Total | 1,106 | 0 | 0.0 | 0.11 | 0.4 | 872 | 0.4 | | N/A |
| Option 4: | | | | | | | | | |
| ERCOT | 98 | 0 | 0.0 | 0.14 | 0.4 | 85 | 0.5 | 0.07 | 0.1 |
| FRCC | 68 | 0 | 0.0 | 0.15 | 0.1 | 33 | 0.2 | 0.09 | 0.1 |
| MRO | 74 | 0 | 0.0 | 0.11 | 0.5 | 134 | 1.0 | −0.05 | −0.1 |
| NPCC | 73 | 0 | 0.6 | 0.03 | 0.1 | 32 | 0.2 | 0.04 | 0.1 |
| RFC | 237 | 1 | 0.3 | 0.29 | 1.1 | 804 | 1.5 | 0.15 | 0.2 |
| SERC | 274 | 0 | 0.0 | 0.28 | 1.0 | 662 | 1.2 | 0.19 | 0.3 |
| SPP | 60 | 0 | −0.6 | 0.15 | 0.5 | 72 | 0.7 | 0.09 | 0.2 |
| WECC | 220 | 0 | 0.0 | 0.03 | 0.1 | 52 | 0.1 | 0.04 | 0.1 |
| Total | 1,106 | 0 | 0.0 | 0.18 | 0.6 | 1,874 | 0.9 | | N/A |

[a] Values for incremental early retirements or closures represent change relative to the baseline run. IPM may show partial (i.e., unit) or full plant early retirements (closures) for a given option. It may also show avoided closures (negative closure values) in which a unit or plant that is projected to close in the baseline, is estimated to continue operating in the post-compliance case. Avoided closures may occur among plants that incur no compliance costs or for which compliance costs are low relative to other steam electric plants.[75]

As shown in Table XI–5, the Market Model Analysis indicates that Option 3 would have very small effects in overall electricity markets, on both a national and regional sub-market basis, in the year 2030. Overall at the national level, the net change in total capacity, including reductions in capacity (which includes early retirements) and capacity additions in new plants/units, results in approximately 1GW of additional capacity (less than 0.05 percent total market capacity), which is too small to appear in Table XI–5. This increase in capacity is expected to take place entirely in the SPP NERC region (0.8 percent of total SPP capacity) and is the result of reduction in retired capacity (avoided capacity closures) and increase in new capacity and capacity at existing generating units.[76] Consequently, Option 3 is expected to have negligible effect on capacity availability and supply reliability at the national level. Overall impacts on electricity prices are similarly minimal. While electricity prices are expected to increase in all NERC regions, the magnitude of this increase varies across regions and ranges from $0.03 per MWh (0.1 percent) in MRO to $0.24 per MWh (0.4 percent) in SERC. Finally, at the national level, total costs increase by approximately 0.4 percent of the baseline value—again, a modest amount. Across regions, no NERC region records an increase in power sector total costs exceeding 1 percent.

The findings for Option 4 *overall* lie very close to those of Option 3. Similar to Option 3, the net change in total capacity under Option 4 is essentially zero, indicating that this option would be expected to have a negligible effect on capacity availability and supply reliability, at the national level. This is also the case at the regional level, with small capacity changes in RFC (early retirement) and SPP (avoided retirement). Option 4 also has a slight impact on electricity prices across all NERC regions, with increases of no more than 0.3 percent and a 0.1 percent reduction in the MRO region. At the national level, variable production costs—fuel and variable O&M—increase by $0.18 per MWh or 0.6 percent. While variable costs increase in all NERC regions, the change varies by region ranging from $0.03 per MWh in NPCC and WECC to $0.29 in RFC. As expected for Option 4, which is more expensive than Option 3, the increase in total annual costs for the electric power sector is greater than under Option 3. At the national level, total annual costs increase by $1.9 billion (0.9 percent). As discussed in greater detail in Chapter 5 of the RIA document, the largest shares of this increase occur in variable O&M; capital costs increase by a much smaller amount. As discussed above, EPA expects the impacts of Options 3a and 3b to be smaller than those of Option 3, and the impacts of Option 4a to be between those of Options 3 and 4.

b. Impact on Existing Steam Electric Plants

EPA used IPM V4.10 results for 2030 to assess the potential impact of the regulatory options on steam electric plants. In contrast to the previously described electricity market-level

[75] Given the design of IPM, unit-level and thereby plant-level projections are presented as an indicator of overall regulatory impact rather than a prediction of future unit- or plant-specific compliance actions. ERCOT (Electric Reliability Council of Texas), 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), and WECC (Western Electricity Coordinating Council).

[76] Avoided capacity closures occur when one or more generating units that are otherwise projected to cease operations in the baseline become more economically attractive sources of electricity in the post-compliance case, because of relative changes in the economics of electricity production across the full market, and thus avoid closure.

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analysis, which sought to assess the impact of the proposed ELGs regulatory options on the entire electric power sector, the purpose of this second analysis is to assess impacts on steam electric plants specifically.

Table XI–6 reports results for steam electric plants, as a group. In this case, EPA looked at the following metrics IPM produces: (1) Incremental early retirements and capacity closures, calculated as the difference between capacity under the regulatory options and capacity under the baseline, which includes both full plant closures and partial plant closures (i.e., unit closures) in aggregate capacity terms; (2) incremental capacity closures as a percentage of baseline capacity; (3) post-compliance change in electricity generation; (4) post-compliance changes in variable production costs per MWh, calculated as the sum of total fuel and variable O&M costs divided by net generation; and (5) changes in annual costs (fuel, variable O&M, fixed O&M, and capital. Items (1) and (2) are instrumental in determining the economic achievability of various regulatory options.

TABLE XI–6—IMPACT OF MARKET MODEL ANALYSIS OPTIONS ON STEAM ELECTRIC PLANTS AS A GROUP AT THE YEAR 2030

| NERC region | Baseline capacity (MW) | Incremental early retirements/ closures [a] | | Change in total generation (GWh or % of baseline) | | Change in variable production cost (2010$/ MWh or % of baseline) | | Change in annual costs (million 2010$ or % of baseline) | |
|---|---|---|---|---|---|---|---|---|---|
| | | Capacity (MW) | % of Baseline capacity | | | | | | |
| Option 3: | | | | | | | | | |
| ERCOT | 32,275 | 0 | 0.0 | −83 | 0.0% | $0.09 | 0.3% | $35 | 0.5% |
| FRCC | 32,227 | 0 | 0.0 | −25 | 0.0 | 0.11 | 0.3 | 27 | 0.4 |
| MRO | 34,899 | 0 | 0.0 | 83 | 0.0 | −0.02 | −0.1 | 26 | 0.3 |
| NPCC | 16,629 | 0 | 0.0 | −3 | 0.0 | 0.07 | 0.2 | 9 | 0.2 |
| RFC | 122,205 | 0 | 0.0 | 234 | 0.0 | 0.15 | 0.5 | 225 | 0.7 |
| SERC | 131,895 | 0 | 0.0 | −1,140 | −0.2 | 0.24 | 0.8 | 283 | 0.8 |
| SPP | 31,269 | −102 | −0.3 | −123 | −0.1 | 0.04 | 0.1 | 15 | 0.2 |
| WECC | 54,494 | 0 | 0.0 | 103 | 0.0 | 0.05 | 0.2 | 22 | 0.2 |
| Total | 455,894 | −102 | 0.0 | −954 | 0.0 | 0.13 | 0.5 | 642 | 0.6 |
| Option 4: | | | | | | | | | |
| ERCOT | 32,275 | 0 | 0.0 | −227 | −0.1 | 0.16 | 0.5 | 66 | 1.0 |
| FRCC | 32,227 | 0 | 0.0 | 78 | 0.1 | 0.05 | 0.1 | 27 | 0.4 |
| MRO | 34,899 | 0 | 0.0 | 212 | 0.1 | 0.12 | 0.5 | 108 | 1.4 |
| NPCC | 16,629 | −431 | −2.6 | −4 | 0.0 | 0.10 | 0.3 | 29 | 0.7 |
| RFC | 122,205 | 681 | 0.6 | −2,351 | −0.3 | 0.38 | 1.3 | 561 | 1.8 |
| SERC | 131,895 | 0 | 0.1 | −2,178 | −0.3 | 0.43 | 1.5 | 607 | 1.8 |
| SPP | 31,269 | −30 | −0.1 | −510 | −0.3 | 0.16 | 0.6 | 59 | 0.9 |
| WECC | 54,494 | 0 | 0.0 | 63 | 0.0 | 0.07 | 0.3 | 46 | 0.4 |
| Total | 455,894 | 317 | 0.1 | −4,916 | −0.2 | 0.28 | 1.0 | 1,504 | 1.4 |

[a] Values for incremental early retirements or closures represent change relative to the baseline run. IPM may show partial (i.e., unit) or full plant early retirements (closures) for a given option. It may also show avoided closures (negative closure values) in which a unit or plant that is projected to close in the baseline, is estimated to continue operating in the post-compliance case. Avoided closures may occur among plants that incur no compliance costs or for which compliance costs are low relative to other steam electric plants. [77]

Under Option 3, the net change in total capacity for steam electric plants is very small; this is similar to prior findings when considering the electricity market as a whole. For the group of steam electric plants, total capacity increases by 106 MW (not shown in Table XI–6, see RIA for details) or approximately 0.02 percent of the 455,894 MW baseline capacity. This results in part from *avoided* capacity closures of 102 MW in the SPP region. Option 3 results in no closures, full (plant) or partial (unit), in the other seven regions.

The change in total generation is an indicator of how steam electric plants fare, relative to the rest of the electricity market. While at the market level there is essentially no projected change in total electricity generation,[78] for steam electric plants, total available capacity and electricity generation at the national level is projected to fall by less than 0.1 percent. At the regional level, five NERC regions—ERCOT, NPCC, RFC, SERC, and SPP—are projected to experience a reduction in electricity generation from steam electric plants, ranging from 3 GWh in NPCC (less than 0.01 percent) to 1,140 GWh in RFC (0.2 percent). The other three NERC regions are each projected to experience a very modest increase in electricity generation from steam electric plants of less than 0.1 percent.

Finally, at the national level, variable production costs at steam electric plants increase by approximately 0.5 percent. These effects vary by region from about −0.1 percent in MRO to 0.8 percent in SERC. These findings of very small national and regional effects in these impact metrics confirm EPA's assessment that Option 3 can be expected to have little economic consequence in national and regional electricity markets.

Results of the analysis for Option 4 show almost no change in either total generating capacity or electricity generation for the electric power sector as whole, and steam electric generating capacity and electricity generation fall slightly by 306 MW (0.07 percent) (not shown in Table XI–6, see RIA for

[77] Given the design of IPM, unit-level and thereby plant-level projections are presented as an indicator of overall regulatory impact rather than a prediction of future unit- or plant-specific compliance actions.

[78] At the national level, the demand for electricity does not change between the baseline and the analyzed regulatory options (generation within the regions is allowed to vary) because meeting demand is an exogenous constraint imposed by the model.

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details) and 4,916 GWh (0.2 percent), respectively. The steam electric capacity reduction includes early retirement and avoided retirement of generating units with the net effect of the two types of changes being capacity losses. Thus, under the analysis for Option 4, 14 generating units close (1,125 MW) and 5 generating units avoid closure (808 MW), leading to an estimated net closure of nine generating units (317 MW, see Table XI–6). All 14 units that are projected to close in this scenario are located within six plants that are projected to continue operating. In other words, Option 4 is not projected to result in any full plant closures.[79]

Findings for the change in total costs and variable production costs under Option 4 also exceed those under Option 3. There is a 1.4 percent increase in total costs at the national level, with SERC recording the largest increase of 1.8 percent. As detailed in Chapter 5 of the RIA document, at the national level, the increase in total costs occurs in fixed and variable O&M (3.2 percent and 9.3 percent, respectively) while fuel costs and capital costs decline (0.4 percent and 3.2 percent, respectively). At the national level, variable production costs increase by 1.0 percent, with SERC recording the highest increase of 1.5 percent. As for impacts on national and regional markets, EPA expects the impacts on steam electric plants of Options 3a and 3b to be smaller than those of Option 3, and the impacts of Option 4a to be between those of Options 3 and 4.

c. Impact on Individual Steam Electric Plants Incurring Compliance Costs Under This Rulemaking

Results for the group of steam electric plants as a whole may mask shifts in economic performance among individual plants incurring compliance costs associated with the proposed ELGs. To assess potential plant-level effects, EPA analyzed plant-specific changes between the base case and the post-compliance cases 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, defined as variable O&M cost plus fuel cost divided by net generation.

Table XI–7 presents the estimated number of plants incurring compliance costs with specific degrees of change in operations and financial performance for the two regulatory options EPA analyzed using IPM. Metrics of interest include the number of plants with reductions in capacity utilization or generation (on left side of the table), and the number of plants with increases in variable production costs (on right side of the table).

TABLE XI–7—IMPACT OF MARKET MODEL ANALYSIS OPTIONS ON INDIVIDUAL STEAM ELECTRIC PLANTS INCURRING COMPLIANCE COSTS AT THE YEAR 2030—NUMBER OF PLANTS BY IMPACT MAGNITUDE

| Economic measures | Reduction | | | No Change | Increase | | | N/A[b] |
|---|---|---|---|---|---|---|---|---|
| | ≥ 3% | ≥1 and <3% | <1% | | <1% | ≥1 and <3% | ≥ 3% | |
| **Option 3** | | | | | | | | |
| Change in Capacity Utilization[a] | 6 | 7 | 62 | 438 | 41 | 4 | 6 | 101 |
| Change in Generation | 15 | 3 | 53 | 443 | 38 | 4 | 8 | 101 |
| Change in Variable Production Costs/MWh | 2 | 3 | 183 | 72 | 239 | 28 | 23 | 115 |
| **Option 4** | | | | | | | | |
| Change in Capacity Utilization[a] | 6 | 4 | 131 | 291 | 113 | 7 | 9 | 104 |
| Change in Generation | 12 | 4 | 118 | 302 | 104 | 6 | 15 | 104 |
| Change in Variable Production Costs/MWh | 2 | 2 | 136 | 46 | 225 | 99 | 37 | 118 |

[a] The change in capacity utilization is the difference between the capacity utilization percentages in the base case and post-compliance cases. For all other measures, the change is expressed as the percentage change between the base case and post-compliance values.

[b] Plants with status changes in either baseline or post-compliance scenario have been excluded from these calculations. For example, for a plant that is projected to close in the post-compliance case, the reduction in variable costs per MWh of generated electricity would be 100 percent. Specifically, there are 23 full baseline plant closures, 77 partial baseline plant closures, and 1 avoided plant closure under Option 3. There are 23 full baseline plant closures, 72 partial baseline plant closures, 3 avoided plant closures, and 6 partial policy plant closures under Option 4.

For Option 3, the analysis of changes in individual plants indicates that most plants experience only slight effects—no change, or less than a 1 percent reduction or 1 percent increase. Only 13 plants (2 percent) are estimated to incur a reduction in capacity utilization exceeding 1 percent and 18 plants (3 percent) incur a reduction in generation exceeding 1 percent. The estimated change in variable production costs is higher; 51 plants (8 percent) incur an *increase* in variable production costs exceeding 1 percent; for 23 of these plants, this increase exceeds 3 percent.

Results for Option 4 show greater effects as compared to Option 3. While the difference in the policy impact on capacity utilization and generation is small, the difference in policy impact on variable costs is greater. The reduction in capacity utilization and generation is estimated to exceed 1 percent for 10 and 16 plants (approximately 2 percent), respectively. The increase in variable production costs is estimated to exceed 1 percent for 136 plants, 99 of which have an increase between 1 and 3 percent.

As for the market and industry-level results discussed above, EPA expects the impacts of Options 3a and 3b to be smaller than those of Option 3, and the impacts of Option 4a to be between those of Options 3 and 4.

3. Summary of Economic Impacts for Existing Sources

EPA performed cost and economic impact assessment in two parts. The first set of cost and economic impact analyses—including entity-level impacts at both the plant and parent company levels—reflects baseline operating characteristics of plants incurring compliance costs and assumes no changes in those baseline operating characteristics (e.g., level of electricity generation and revenue) as a result of the requirements of the proposed regulatory options. They can serve as screening-level indicators of the relative cost of different regulatory options to plants, owning entities, or consumers, but are not determinative in terms of

[79] Given the design of IPM, unit-level and thereby plant-level projections are presented as an indicator of overall regulatory impact rather than a prediction of future unit- or plant-specific compliance actions.

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assessing the economic achievability of various regulatory options.

The second set of analyses look at broader electricity market impacts taking into account the interconnection of regional and national electricity markets, for the full industry, for steam electric plants only, and at the distribution of impacts at the plant level. This second analysis provides insight on the impacts of the proposed ELGs on steam electric plants, as well as the electricity market as a whole, including generation capacity closure, and changes in generation and wholesale electricity prices. Results of the Market Model for Option 3 show no incremental plant closures (complete or partial) and relatively small changes in production costs. This analysis shows that Option 3 for existing steam electric plants is economically achievable. This same conclusion applies to Options 3a and 3b since the costs of these options are less than those of Option 3.

The Market Model analysis of Option 4 shows slightly higher, but still relatively small, impacts on steam electric generation and individual plants as compared to Option 3. For example, the results show incremental partial capacity retirements of 317 MW at the national level (1.4 percent relative to the baseline without the proposed ELGs), no full plant retirements, and greater increases in production costs (1.0 percent), as compared to Option 3. Given these impacts, and since the impacts of Option 4a would fall between those of Options 3 and 4, EPA believes that Option 4a is also economically achievable.

4. Summary of Economic Impacts for New Sources

Electric power generating units that meet the definition of a new source would be required to meet the proposed NSPS or PSNS. EPA developed estimated compliance costs for new units using a methodology similar to that used to develop compliance costs for existing plants, with the notable exception that EPA did not develop new unit compliance costs that are plant specific, which would require EPA to predict which plants will construct new units.

EPA assessed the possible impact of incremental costs associated with this proposal for new units in two ways: (1) As part of its analysis using IPM discussed in Section XI.D.3; and (2) by comparing the incremental costs for new units to the overall cost of building and operating new scrubbed coal units.

EPA estimated the incremental capital and fixed O&M costs for each new electricity generating coal unit projected to come online in IPM. The Agency estimated variable O&M costs assuming that any new unit would operate, on average, 330 days per year. IPM takes these additional regulatory costs into account when trying to determine the least costly means of meeting the total electricity demand. Results of the IPM analysis are summarized in Section XI.D.3 of this preamble and discussed in detail in Chapter 5 of the RIA document. IPM results show no barrier to new generation capacity for 2025–2034 as a result of compliance with the preferred NSPS/PSNS regulatory options (Option 4). The model estimates no change in coal steam capacity relative to the baseline, and small increases in generation capacity from other steam (0.3 percent), combustion turbine (0.3 percent), other non-steam (less than 0.1 percent), and combined cycle (less than 0.1 percent) units.[80]

As a separate analysis, EPA also compared total compliance costs to the total cost of building and operating a new coal unit on an annualized basis. EPA obtained the overnight[81] capital and O&M costs of building and operating a new scrubbed coal unit used in the Energy Information Administration's Annual Energy Outlook 2011; these costs were estimated for a new dual-unit plant with a total generation capacity of 1,300 MW. Table XI–8 shows capital and O&M costs of building and operating a new coal unit and contrasts these costs with the incremental costs associated with the preferred option (i.e., Option 4 for new sources).

TABLE XI–8—COMPARISON OF INCREMENTAL COMPLIANCE COSTS WITH COSTS FOR NEW COAL-FIRED STEAM ELECTRIC UNITS

| Cost component | Costs of new coal generation ($2010/MW)[a] | Incremental compliance costs ($2010/MW)[b] | Percent of new generation cost |
|---|---|---|---|
| Capital | $2,981,947 | $19,911–$21,773 | 0.7–0.7 |
| Annual O&M | 66,427 | 2,281–$3,093 | 3.4–4.7 |
| Total Annualized Costs | 329,487 | 4,037–$5,013 | 1.2–1.5 |

[a] Source: New unit total cost value from Table 8.2 EIA NEMS Electricity Market Module. AEO 2011 Documentation. Available at *http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf.* Capital costs are based on the total overnight costs for new scrubbed coal dual-unit plant, 1,300 MW capacity coming online in 2014. EPA restated costs in 2010 dollars. Total annual O&M costs assume 90% capacity utilization.
[b] Incremental costs for new 1300 MW unit for Option 4. Range represents the costs for a new unit at an existing plant (lower bound) and new unit at newly constructed plant (upper bound).

The comparison suggests that compliance with the proposed ELGs represents a relatively small fraction of overnight capital costs of a new unit (less than 1 percent) and a somewhat higher, but still small (less than 5 percent), fraction of non-fuel O&M costs. On an annualized basis, compliance costs for the proposed ELGs are 1.2 to 1.5 percent of annualized costs for a new plant.

Based on these two separate assessments, EPA finds no evidence that the incremental compliance costs associated with the proposed NSPS/PSNS present a barrier to entry.

5. Assessment of Potential Electricity Price Effects

EPA assessed the potential electricity price effects of this proposed rule in two ways: (1) an assessment of the potential annual increase in household electricity costs and (2) an assessment of the potential annual increase in electricity costs per MWh of total electricity sales.

[80] Other steam generation includes biomass, landfill gas, fossil waste, municipal solid waste, non-solid waste, tires, and geothermal. Other non-steam generation includes wind, solar, pumped storage, and fuel cell.

[81] As defined by the Energy Information Administration, "overnight cost" is an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. This concept is useful to avoid any impact of project delays and of financing issues and assumptions on estimated costs.

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The analysis assumes, for analytic convenience as a worst-case scenario, that *all* compliance costs will be passed through on a pre-tax basis as increased electricity prices as opposed to the treatment in the plant- and entity-level analyses discussed in Section XI.D.1 above, which assume that *none* of the compliance costs will be passed to consumers through electricity rate increases.

a. Cost to Residential Households

Using the assumptions outlined above, EPA estimated the potential annual increase in electricity costs per household, by North American Electric Reliability Corporation (NERC) region. The analysis uses the total annualized pre-tax compliance cost per megawatt hour (MWh) for the year 2014 (in 2010 dollars), in conjunction with the reported total electricity sales quantity for each NERC region for 2009. This analysis also uses the quantity of residential electricity sales per household in 2009. To calculate the average cost per household, by region, EPA divided total compliance costs for each NERC region by the reported total MWh of sales within the region. The potential annual cost impact per household was then calculated by multiplying the estimated average cost per MWh by the average MWh per household, by NERC region.[82] Details of this analysis are presented in Chapter 7 of the RIA.

Table XI–9 summarizes the annual household impact results for each regulatory option, by NERC region. The results for Option 3a show the average annual cost per residential household increasing by $0 to $1.69 depending on the region, with a national average of $0.48. This represents a monthly increase of $0.04 for the typical household. For Option 3b, the results show the average annual cost per residential household increasing by $0 to $2.29, with a national average of $0.75, or $0.06 per month. For Option 3, the average annual cost per residential household increases by $0 to $4.40, with a national average of $1.59, or $0.13 per month. Finally, for Option 4a, the average annual cost per residential household increases by $0 to $7.22, depending on the region, with a national average of $2.69, or $0.22 per month.

TABLE XI–9—AVERAGE ANNUAL COST BURDEN PER RESIDENTIAL HOUSEHOLD IN 2014 BY REGULATORY OPTION AND NERC REGION

[2010$] [a]

| NERC Region | Option 3a | Option 3b | Option 1 | Option 2 | Option 3 | Option 4a | Option 4 | Option 5 |
|---|---|---|---|---|---|---|---|---|
| ASCC | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| ECAR | 1.69 | 2.29 | 1.82 | 2.71 | 4.40 | 7.22 | 10.08 | 16.86 |
| ERCOT | 0.00 | 0.42 | 1.22 | 1.73 | 1.73 | 2.60 | 2.79 | 5.76 |
| FRCC | 0.00 | 0.00 | 0.18 | 0.67 | 0.67 | 0.67 | 0.99 | 4.32 |
| HICC | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| MAAC | 0.00 | 0.00 | 0.06 | 0.32 | 0.32 | 0.97 | 2.04 | 3.52 |
| MAIN | 0.31 | 0.31 | 0.48 | 0.69 | 1.01 | 2.55 | 4.63 | 6.16 |
| MAPP | 0.01 | 0.01 | 0.97 | 1.30 | 1.32 | 2.04 | 3.23 | 5.58 |
| NPCC | 0.00 | 0.00 | 0.03 | 0.08 | 0.08 | 0.08 | 0.49 | 0.67 |
| SERC | 1.09 | 2.00 | 1.63 | 2.19 | 3.28 | 4.98 | 6.47 | 10.81 |
| SPP | 0.05 | 0.14 | 0.61 | 0.96 | 1.01 | 2.85 | 4.43 | 6.30 |
| WECC | 0.05 | 0.05 | 0.02 | 0.03 | 0.08 | 0.23 | 0.53 | 0.59 |
| U.S. | 0.48 | 0.75 | 0.75 | 1.12 | 1.59 | 2.69 | 3.89 | 6.46 |

[a] The rate impact analysis maintains the counterfactual, conservative assumption of 100 percent pass-through to electricity consumers.

As stated above, this analysis assumes that all of the compliance costs (100 percent) will be passed onto consumers through increased electricity rates. However, plants and owning entities are likely to absorb some of these costs, thereby reducing the impact of the proposed ELGs on electricity consumers. At the same time, EPA recognizes that electric generators that operate as regulated public utilities are generally permitted to pass on environmental compliance costs as rate increases to consumers. To evaluate the sensitivity of the results to the pass-through assumption, EPA analyzed alternative scenarios including cases where only half (50 percent) of the incremental compliance costs are passed onto consumers. Appendix B of the RIA report presents the results of this sensitivity analysis. The results show smaller impacts on electricity rates, commensurate with the smaller fraction of the compliance costs that are passed onto consumers.

b. Compliance Costs per Unit of Electricity Sales

As an additional measure of the potential electricity price effects associated with the proposed ELGs, EPA also assessed the potential increase in electricity prices to all consumer groups (residential, commercial, industrial, and transportation), again making a counterfactual, conservative assumption of a 100 percent pass-through of compliance costs. This assessment uses as its basis the cost of the regulatory options per unit of electricity sold.

EPA used two data inputs in this analysis (1) total pre-tax compliance cost by NERC region, and (2) estimated total electricity sales for 2014, by NERC region. The Agency summed sample-weighted pre-tax annualized compliance costs as of 2014 over complying plants by NERC region to calculate the total estimated annual cost in each 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 Chapter 7 of the RIA report.

As reported in Table XI–10, on average, across the United States, Option 5 results in the highest increased compliance cost of 0.059¢ per kWh. Annualized compliance costs (in dollars per KWh sales) associated with Option 3a range from 0¢ to 0.016¢, depending on the region, with a national average of

[82] Some NERC regions have been re-defined over the past few years. The NERC region definitions used in this proposed rule analyses vary by analysis depending on which region definition aligns better with the data elements underlying the analysis.

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0.004¢ per KWh. For Option 3b, annualized compliance costs range from 0¢ to 0.022¢, with a national average of 0.007¢ per KWh, whereas Option 3 has a range of 0¢ to 0.042¢ per kWh and a national average of 0.015¢ per kWh and Option 4a has a range of 0¢ to 0.068¢ per kWh and a national average of 0.025¢ per kWh. To determine the potential significance of these compliance costs on electricity prices, EPA compared the per kWh compliance cost to baseline electricity prices by consuming sector, and for the average of the sectors. Across the United States and consuming sectors, Option 3a is estimated to result in the smallest electricity price increase, 0.05 percent; the other preferred BAT and PSES options, Options 3b, 3 and 4a, have estimated increases of 0.08 percent, 0.16 percent and 0.27 percent, respectively.

TABLE XI–10—COMPLIANCE COST PER UNIT OF ELECTRICITY SALES IN 2014 BY REGULATORY OPTION AND NERC REGION

[2010 ¢/KWh Sales] [a]

| NERC Region | Option 3a | Option 3b | Option 1 | Option 2 | Option 3 | Option 4a | Option 4 | Option 5 |
|---|---|---|---|---|---|---|---|---|
| ASCC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| ECAR | 0.016 | 0.022 | 0.017 | 0.026 | 0.042 | 0.068 | 0.095 | 0.159 |
| ERCOT | 0.000 | 0.003 | 0.009 | 0.012 | 0.012 | 0.019 | 0.020 | 0.041 |
| FRCC | 0.000 | 0.000 | 0.001 | 0.005 | 0.005 | 0.005 | 0.007 | 0.032 |
| HICC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| MAAC | 0.000 | 0.000 | 0.001 | 0.003 | 0.003 | 0.010 | 0.021 | 0.036 |
| MAIN | 0.003 | 0.003 | 0.005 | 0.008 | 0.011 | 0.028 | 0.051 | 0.068 |
| MAPP | 0.000 | 0.000 | 0.009 | 0.012 | 0.013 | 0.019 | 0.031 | 0.053 |
| NPCC | 0.000 | 0.000 | 0.000 | 0.001 | 0.001 | 0.001 | 0.007 | 0.009 |
| SERC | 0.008 | 0.014 | 0.012 | 0.016 | 0.023 | 0.035 | 0.046 | 0.076 |
| SPP | 0.000 | 0.001 | 0.005 | 0.008 | 0.008 | 0.023 | 0.036 | 0.051 |
| WECC | 0.001 | 0.001 | 0.000 | 0.000 | 0.001 | 0.002 | 0.006 | 0.006 |
| U.S. | 0.004 | 0.007 | 0.007 | 0.010 | 0.015 | 0.025 | 0.036 | 0.059 |

[a] This analysis makes a counterfactual, conservative assumption of 100 percent pass-through to electricity consumers.

As mentioned in the previous section, EPA ran alternative scenarios using an assumption that only half (50 percent) of the incremental compliance costs are passed onto consumers. The results of these alternative scenarios showed commensurately smaller impacts on compliance costs per unit of electricity sold (see Appendix B of the RIA report).

*E. Employment Effects*

EPA assessed the potential for employment impacts at the national level for the eight regulatory options considered in this action.

1. Methodology

The employment effects analysis estimates employment changes only in the directly regulated electric power industry sector at the national level. This analysis focuses on the longer-term, on-going employment effects of meeting compliance requirements, and accounts for all compliance costs, regardless of their time, duration, or frequency of occurrence. Morgenstern, Pizer and Shih (2000) explore both theoretically and empirically the relationship between employment and compliance costs of environmental regulation. Morgenstern et al. identify three separate components of the employment change within a regulated industry in response to a regulation. First, complying with environmental regulations causes higher production costs which raises market prices, higher prices reduce consumption (and production) reducing demand for labor within the regulated industry ("demand effect"). Second, as costs go up, to produce the same level of output, plants add more capital and labor. For example, pollution abatement activities require additional labor services to produce the same level of output ("cost effect"). Third, post-regulation production technologies may be more or less labor intensive (i.e., more/less labor is required per dollar of output) ("factor-shift effect"). The demand effect is unambiguously negative, the cost effect is unambiguously positive and the factor-shift effect could be positive or negative making the total effect theoretically indeterminate. In addition, Morgenstern et al. also estimate an empirical model for four highly polluting/regulated industries to examine the effect of higher abatement costs from regulation on employment. They conclude that increased abatement expenditures generally do not cause a significant change in employment. More specifically, their results show that, on average across their industries, each additional $1 million spending on pollution abatement (in $1987 dollars) results in a (statistically insignificant) net increase of 1.5 jobs (95 percent confidence interval: −2.9 to + 6.0).

2. Findings

Table XI–11 presents the estimated change, based on the Morgenstern et al. results, in employment in the electric power industry due to the proposed ELGs under each of the eight regulatory options. The table lists the options in increasing order of employment effects. Overall, in the aggregate and by a specific employment effect, Option 1 is projected to have the smallest effect and Option 5 is projected to have the largest effect on employment. The Demand Effect is projected to result in a decline in the number of jobs, while the Cost Effect and Factor Shift Effect are projected to result in an increase in the number of jobs.

EPA estimated an average annual increase of 168 jobs under proposed Option 3a for existing sources. For proposed Option 3b, the average annual increase is estimated at 255 jobs, whereas Options 3 and 4a have estimated increases of 519 jobs and 865 jobs, respectively. Because the electric utility industry is more capital intensive and less labor intensive than the industries examined in Morganstern, Pizer and Shih, in addition to the employment estimates being statistically not distinguishable from the effect being zero, the estimates presented here are likely to be over-estimated. Chapter 6 of the RIA report describes the methodologies and results in greater detail.

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TABLE XI–11—RESULTS OF ONGOING EMPLOYMENT EFFECTS ON THE ELECTRIC POWER INDUSTRY SECTOR (NUMBER OF JOBS) [a b]

| Regulatory option | Employment effect | Total annual average employment effect |
|---|---|---|
| Option 3a | Cost | 262 |
| | Factor Shift | 291 |
| | Demand | −386 |
| | Total | 168 |
| Option 1 | Cost | 380 |
| | Factor Shift | 421 |
| | Demand | −559 |
| | Total | 243 |
| Option 3b | Cost | 399 |
| | Factor Shift | 441 |
| | Demand | −586 |
| | Total | 255 |
| Option 2 | Cost | 548 |
| | Factor Shift | 607 |
| | Demand | −806 |
| | Total | 548 |
| Option 3 | Cost | 810 |
| | Factor Shift | 897 |
| | Demand | −1,192 |
| | Total | 519 |
| Option 4a | Cost | 1,351 |
| | Factor Shift | 1,496 |
| | Demand | −1,988 |
| | Total | 865 |
| Option 4 | Cost | 1,956 |
| | Factor Shift | 2,166 |
| | Demand | −2,878 |
| | Total | 1,253 |
| Option 5 | Cost | 3,298 |
| | Factor Shift | 3,653 |
| | Demand | −4,852 |
| | Total | 2,112 |

[a] Source: Morgenstern, Pizer, and Shih (2002).

[c] Coefficients from Table III, p. 427, for the Cost, Demand, Factor Shift and Total Effects were multiplied by the annualized cost of the proposed ELGs calculated as part of the social cost analysis (see Section XI.C) during the 24-year analysis period and re-stated in 1987 dollars, by the coefficient for the net increase in jobs.

Number of jobs is the average number of production workers plus other employees. The definition for employment used by the U.S. Census Bureau's Annual Survey of Manufacturers can be found here: *http://www.census.gov/manufacturing/asm/definitions/index.html.*

## XII. Cost-Effectiveness Analysis

EPA performed a cost-effectiveness analysis of the regulatory options for existing plants. EPA often uses cost-effectiveness analysis in the development/revision of effluent limitations guidelines and standards to evaluate the relative efficiency of alternative regulatory options in removing toxic pollutants from the effluent discharges to the nation's waters. Although not required by the Clean Water Act, cost-effectiveness analysis is a useful tool for evaluating regulatory options that address toxic pollutants.

### *A. Methodology*

The cost-effectiveness of a regulatory option is defined as the incremental annual cost (in 1981 constant dollars) per incremental toxic-weighted pollutant removals for that option. This definition includes the following concepts:

*Toxic-weighted removals.* Pollutants differ in their toxicity. Therefore, the estimated reductions in pollution discharges, or pollutant removals, are adjusted for toxicity by multiplying the estimated removal quantity for each pollutant by a normalizing toxic weight (toxic weighting factor). The toxic weight for each pollutant measures its toxicity relative to copper, with more toxic pollutants having higher toxic weights. The use of toxic weights allows the removals of different pollutants to be expressed on a constant toxicity basis as toxic pound-equivalents (lb-eq). The removal quantities for the different pollutants can then be summed to yield an aggregate measure of the reduction in toxicity-normalized pollutant discharges that is achieved by a regulatory option. The cost-effectiveness analysis does not address the removal of conventional pollutants (e.g., total suspended solids) or nutrients (nitrogen, phosphorus), nor does it address the removal of bulk parameters, such as COD. In the case of indirect dischargers, the removal also accounts for the effectiveness of treatment at publicly owned treatment works (POTW) and reflects the toxic-weighted pounds remaining after POTW treatment.

*Annual costs.* The costs used in the cost-effectiveness analysis are the estimated annualized pre-tax costs to comply with the alternative regulatory options (refer to Section XI for a discussion of the annualized compliance costs). These costs to plants to remove the pollutants will be less because the costs are tax deductible. The annual costs include the annualized capital outlays for equipment and recurring expenses for operating and maintaining compliance equipment, meeting monitoring requirements, etc.

*Incremental calculations.* The incremental values are the changes in total annual compliance costs and changes in pollutant removals as one moves to a regulatory option from the next less stringent regulatory option, or from the baseline for the least stringent option analyzed, where regulatory options are ranked by increasing levels of toxic-weighted removals. The resulting cost-effectiveness values for a given option are, therefore, expressed relative to another option or, for the least stringent option considered, relative to the baseline.

The result of the cost-effectiveness calculation represents the unit cost of removing the next pound-equivalent of pollutants and is expressed in constant 1981 dollars per toxic pound-equivalent removed ($/lb-eq) to allow comparisons with the reported cost effectiveness of other effluent guidelines, which use 1981 dollars.

EPA performed the cost-effectiveness analysis for the eight regulatory options for the proposed Steam Electric ELGs separately for existing direct dischargers (subject to BAT) and indirect dischargers (subject to PSES). The following sections summarize the results. Note that the same plant may be categorized as a direct discharger for one of the wastestreams it generates and as an indirect discharger for another.

### *B. Cost-Effectiveness Analysis for Direct Dischargers*

Table XII–1 summarizes the cost-effectiveness analysis for the BAT regulatory options applicable to direct dischargers. The table lists the options in increasing order of total annual toxic-weighted pollutant removals.

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TABLE XII–1—COST-EFFECTIVENESS OF REMOVING TOXIC POLLUTANTS FOR DIRECT DISCHARGERS [a]

| Option | Annual pre-tax compliance costs (million, 1981$) | | Total annual toxic-weighted pollutant removals (000 lb-eq) | | Cost effectiveness (1981$/lb-eq) | |
|---|---|---|---|---|---|---|
| | Option total cost | Incremental cost | Option total removals | Incremental removals | Option cost effectiveness | Incremental cost effectiveness |
| Option 1 | $105.6 | $105.6 | 1,530,719 | 1,530,719 | $69 | $69 |
| Option 3a | 67.5 | −38.1 | 2,488,470 | 957,751 | 27 | −40 |
| Option 2 | 156.0 | 88.5 | 2,603,628 | 115,158 | 60 | 768 |
| Option 3b | 106.3 | −49.7 | 3,396,653 | 793,025 | 31 | −63 |
| Option 3 | 223.5 | 117.2 | 5,092,098 | 1,695,445 | 44 | 69 |
| Option 4a | 378.7 | 155.2 | 6,664,693 | 1,572,595 | 57 | 99 |
| Option 4 | 547.9 | 169.2 | 7,831,298 | 1,166,605 | 70 | 145 |
| Option 5 | 906.5 | 358.5 | 8,200,804 | 369,506 | 111 | 970 |

[a] Options are ranked by increasing levels of total annual toxic-weighted removals.

As shown in Table XII–1, the proposed technology bases for BAT have a cost-effectiveness ratio of $27/lb-eq, $31/lb-eq, $44/lb-eq, and $57/lb-eq, respectively for Options 3a, 3b, 3 and 4a ($1981). These cost-effectiveness ratios are well within the range of cost-effectiveness ratios for BAT of other industries. A review of approximately 25 of the most recently promulgated or revised BAT limitations shows BAT cost-effectiveness ranging from less than $1/lb-eq (Inorganic Chemicals) to $404/lb-eq (Electrical and Electronic Components), in 1981 dollars.

*C. Cost-Effectiveness Analysis for Indirect Dischargers*

Table XII–2 summarizes the cost-effectiveness analysis for the PSES regulatory options applicable to indirect dischargers. Toxic-weighted pollutant removals for indirect dischargers account for POTW removal efficiencies. The table lists the options in increasing order of total annual toxic-weighted pollutant removals.

TABLE XII–2—COST-EFFECTIVENESS OF REMOVING TOXIC POLLUTANTS FOR INDIRECT DISCHARGERS [a]

| Option | Annual pre-tax compliance costs (million, 1981$) | | Total annual toxic-weighted pollutant removals (000 lb–eq) | | Cost effectiveness (1981$/lb-eq) | |
|---|---|---|---|---|---|---|
| | Option total cost | Incremental cost | Option total removals | Incremental removals | Option cost effectiveness | Incremental cost effectiveness |
| Option 3a | $0.0 | $0.0 | 0 | 0 | | |
| Option 3b | 0.0 | 0.0 | 0 | 0 | | |
| Option 1 | 1.2 | 1.2 | 3,540 | 3,540 | $345 | $345 |
| Option 2 | 2.0 | 0.7 | 11,711 | 8,171 | 168 | 92 |
| Option 3 | 2.0 | 0.0 | 11,711 | 0 | 168 | |
| Option 4a | 2.0 | 0.0 | 11,711 | 0 | 168 | |
| Option 4 | 3.6 | 1.6 | 15,532 | 3,821 | 233 | 430 |
| Option 5 | 8.1 | 4.5 | 18,297 | 2,765 | 445 | 1,636 |

[a] Options are ranked by increasing levels of total annual toxic-weighted removals.

As shown in Table XII–2, there are no indirect dischargers that would incur compliance costs or result in incremental pollutant removals under Options 3a and 3b, whereas Options 3 and 4a both have a cost effectiveness of $168/lb-eq ($1981). The cost-effectiveness of Options 3 and 4a is within the range of cost-effectiveness for PSES of other industries. A review of approximately 25 of the most recently promulgated or revised categorical pretreatment standards shows PSES cost-effectiveness ranging from less than $1/lb-eq (Inorganic Chemicals) to $380/lb-eq (Transportation Equipment Cleaning), in 1981 dollars.

## XIII. Environmental Assessment

This section describes the environmental assessment conducted in support of this rulemaking. The environmental assessment reviewed currently available literature on the documented environmental and human health impacts of combustion wastewaters and conducted modeling to determine the cumulative impacts caused by the universe of steam electric power plants proposed to be regulated under this effluent limitations guidelines and standards. Modeling calculated both the impacts at baseline conditions (current conditions), and the improvements that will result after implementation of the different potential control options. The environmental improvements discussed in Section XIII.A below are those for the preferred BAT and PSES regulatory options (Option 3a, Option 3b, Option 3, and Option 4a).

A complete review of the scientific literature and a full description of EPA's modeling analysis (including the results for all other control options) are provided in the *Environmental Assessment of the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category.*

Current scientific literature indicates that combustion wastewaters such as fly ash and bottom ash transport water, FGD wastewater, and combustion residual leachate are toxic wastes and are causing significant detrimental environmental and human health impacts. Documented environmental impacts from exposure to these wastes reveals that the threat posed to human health, wildlife and the environment is a widespread problem that is not isolated to a few unique locations or circumstances. Documented instances of drinking water maximum contaminant

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level (MCL) exceedances near steam electric power plants and the issuance of fish advisories in waters that receive combustion wastewater indicates the likely threat of human health impacts from these wastestreams (see Section 3.4.2 of the Environmental Assessment). In addition, one recent study provides confirming empirical evidence that toxic wastes are currently damaging aquatic life and accumulating in the environment and will only get worse.[83]

Ecological impacts include both acute (e.g., fish kills) and chronic effects (e.g., malformations, and metabolic, hormonal, and behavioral disorders) upon biota within the receiving water and the surrounding environment. Bioaccumulative toxic metals (e.g., selenium, mercury, and arsenic) are commonly cited as the primary cause for ecological damage following exposure to combustion wastewater. Selenium is the most frequently cited metal associated with environmental impacts following exposure to combustion wastewater discharges. Documented selenium-related impacts include lethal effects such as fish kills and sublethal effects such as histopathological changes (i.e., accumulation of trace elements in tissue) and damage to reproductive and developmental success. Other metals in combustion wastewater discharges such as arsenic, cadmium, chromium, copper, and lead have also been documented as causing sublethal effects such as changes to morphology (e.g., fin erosion, oral deformities), behavior (e.g., swimming ability, ability to catch prey, ability to escape from predators), and metabolism that can negatively affect long-term survival. Combined, these impacts can drastically alter aquatic populations and communities and the surrounding ecosystems that rely on them.

Recovery of the environment from exposure to combustion wastewater discharges can be extremely slow due to the accumulation and continued cycling of contaminants within the ecosystem and the potential to alter ecological processes, such as population diversity and community dynamics in the surrounding ecosystems. The ability of aquatic and adjacent terrestrial environments to recover from even short periods of exposure to these wastes depends on, among other factors, the distance from the discharge, the pollutant loadings, pollutant residence time, and the time elapsed since exposure. In particular, accumulation of metals in sediments can make recovery of aquatic systems following exposure to combustion wastewater discharges exceptionally slow due to the potential for resuspension in the water column and for benthic organisms to provide a pathway for exposure long after discharges have ended. In addition, metals such as selenium and arsenic bioaccumulate in organisms exposed to combustion wastewater discharges further complicating the potential magnitude of impacts these wastes pose.

EPA identified several cases in the literature where metals from combustion wastewater discharges bioaccumulated to toxic levels in organisms inhabiting aquatic environments even with low concentrations of these contaminants. The strong bioaccumulative properties of the pollutants, in conjunction with long residence times, emphasize the threat these wastes present to the local environment as many of the impacts may not be fully realized for years to come.

In addition to the bioaccumulative and toxic properties of the pollutants in combustion wastewaters, the total pollutant loadings associated with these discharges are large (see Section IX). EPA estimates that discharges from steam electric power plants alone contribute 50 to 60 percent of the reported toxic-weighted pollutant loadings of the combined discharges of all industrial categories currently regulated in the U.S. Further, many steam electric power plants discharge to sensitive environments where pollutant loadings contribute to reduced water quality (e.g., Great Lakes, valuable estuaries, 303(d) listed waters, drinking water sources, and waters with fish consumption advisories).

EPA has determined that 25 percent of surface waters that receive combustion wastewater discharges are impaired for a pollutant associated with combustion wastewater; 38 percent of surface waters are under a fish advisory for a pollutant associated with combustion wastewater. In addition to the concurrence of combustion wastewater discharges in close proximity to sensitive environments, EPA has identified over 120 steam electric power plants with documented environmental impacts to surface water and ground water environments following exposure to combustion wastewater, which is further evidence these wastes are of great concern. While in the past these cases may have been assumed to be anomalies, an increasing amount of evidence indicates that the characteristics contributing to the documented impact (e.g., size of the pollutant loadings, type of pollutant present in the waste, plant operations, and wastewater handling techniques) are common among power plant discharge locations. Further, as explained earlier, these documented impacts do not yet reflect the increased pollutant loadings associated with increasing use of air pollution controls. This, when coupled with the potential for long-term persistent impacts due to bioaccumulative pollutants, indicates that these impacts most likely are occurring in other locations around the country even though they have not yet been documented. This suggests that the magnitude of the environmental impact of combustion wastewater discharges is potentially greater than the literature estimates.

In addition, EPA has identified other potential impacts from combustion wastewater discharges. Steam electric plants also discharge bromide in large quantities. Bromide in wastewater discharges from steam electric plants located upstream from a drinking water intake has been associated with the formation of trihalomethanes (THMs) and haloacetic acids (HAAs) when it is exposed to chlorination disinfection processes in drinking water treatment plants. Bromate, a disinfection byproduct (DBP) associated with drinking water treatment plants that employ ozonation may also increase under the influence of increased bromide in the source water. Human exposure to THMs and DBPs in chlorinated drinking water is associated with bladder cancer.

Based on the documented environmental impacts discussed in the literature, EPA identified several key environmental and human health concerns and pathways of exposure to evaluate in the environmental assessment. These included changes in surface water, sediment, and ground water quality; toxic effects on aquatic life; toxic metal bioaccumulation in fish and in piscivorous wildlife (e.g., minks and bald eagles); toxic metal bioaccumulation in fish consumed by humans; and contamination of ground water drinking water resources.

EPA developed a three-part receiving water model to quantify changes in plant-specific impacts to surface waters, wildlife, and human health from pollutant reductions associated with the regulatory options discussed in Section VIII for a subset of evaluated wastestreams from steam electric power plants (i.e., fly ash and bottom ash transport water, FGD wastewater, and leachate). EPA considered the type of

[83] Ruhl, L., A. Vengosh, G.S. Dwyer, H. Hsu-Kim, G. Schwartz, A. Romanski, and S.D. Smith. 2012. The Impact of Coal Combustion Residue Effluent on Water Resources: A North Carolina Example. Environmental Science and Technology. DCN SE01984.

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receiving waters commonly impacted by steam electric power plants and the pollutants typically found in the evaluated wastestreams in selecting the appropriate methodologies for the quantitative Environmental Assessment analysis. EPA designed the model to quantify the environmental impact within rivers/streams and lakes/ponds (including reservoirs) based on the finding that 94 percent of the power plant outfalls discharge to these types of surface waters. EPA focused the modeling on toxic metals due to the total mass loadings discharged, potential for toxic effects to wildlife and human health, and potential for bioaccumulation within the ecosystem. EPA addressed environmental impacts from nutrients, in a separate analysis discussed in Section XIII.E.

EPA's environmental assessment modeling includes three interrelated models: 1) a receiving water-scale water quality model; 2) a receiving water-scale wildlife model; and 3) a receiving water-scale human health model. Each of these models evaluates changes in environmental and human health effects under baseline conditions and five of the regulatory options discussed in Section VIII of this preamble (Options 1, 2, 3, 4, and 5). The receiving water-scale water quality model estimates the concentration of metals (i.e., arsenic, cadmium, chromium VI, copper, lead, mercury, nickel, selenium, thallium, zinc) in the surface waters and sediments in the immediate discharge zone (i.e., approximately one to 10 kilometers [km] from the outfall) for steam electric power plants with direct discharge loadings included in the costs and loadings analysis (see Section IX). EPA compared modeled receiving water concentrations based on pollutant loadings from the evaluated wastestreams against National Recommended Water Quality Criteria (NRWQC) and Maximum Contaminant Levels (MCLs) to assess changes in receiving water quality. The wildlife model evaluates the potential impact that water and sediment concentrations pose to aquatic life, calculates the metal concentrations in exposed fish populations, and evaluates the potential impact to wildlife (minks and eagles) from consumption of fish. The human health model calculates potential threat to cause non-cancer health effects and cancer risks to human populations from the consumption of fish exposed to discharges of the evaluated wastestreams. In addition to the immediate receiving water analysis, EPA modeled receiving water concentrations downstream from steam electric discharges using EPA's Risk-Screening Environmental Indicators (RSEI) model and used the wildlife and human health models to calculate metal concentrations in exposed fish populations and human exposure doses from fish consumption in surface waters downstream from steam electric discharges. EPA compared downstream receiving water concentrations, fish tissue concentrations, and human exposure to water quality, wildlife, and non-cancer and cancer benchmarks to assess the number of improved river miles associated with the different options for this proposed rule.

EPA did not perform modeling to evaluate changes in environmental and human health effects under Option 3a, Option 3b, or Option 4a. To estimate the environmental improvements under these three options, the Agency compared their pollutant load reductions to those of Option 3 (whose reductions would be greater than those of Option 3a and Option 3b, and less than those of Option 4a) and applied corresponding adjustments to the modeled environmental improvements under Option 3 to approximate those of the three un-modeled options.

EPA expects a number of environmental and ecological improvements and reduced impacts to wildlife and human receptors to result from reductions in effluent loadings examined for the different options discussed in this proposed rule. In particular, the Environmental Assessment evaluated the following: a) improvements in water quality, b) reduction in impacts to wildlife, c) reduction in number of receiving waters with potential human health cancer risks, d) reductions in number of receiving waters with potential to cause non-cancer human health effects, e) reduction in nutrient impacts, f) reduction in other environmental impacts, and g) unquantified environmental improvements.

*A. Improvements in Surface Water and Ground Water Quality*

The reduced pollutant loadings associated with the preferred options (Option 3a, Option 3b, Option 3, and Option 4a) would lead to reduced contamination levels in surface waters and sediments. EPA estimated that reduced pollutant loadings to surface waters associated with Option 3a would significantly improve water quality by reducing metal concentrations by up to 33 percent on average within the immediate receiving waters. Option 3b, Option 3, and Option 4a would achieve average reductions of up to 36 percent, 48 percent, and 60 percent, respectively. The pollutants with the greatest number of water quality standard (NRWQC or MCL) exceedances under baseline pollutant loadings include: total arsenic, total thallium, dissolved cadmium, and total selenium. EPA determined that 49 percent of the immediate receiving waters exceeded a water quality standard under baseline loadings. EPA estimates the number of immediate receiving waters with aquatic life exceedances, which are driven by dissolved cadmium and total selenium concentrations, would be reduced by up to 29 percent for both Option 3a and Option 3b, up to 35 percent for Option 3, and up to 55 percent for Option 4a under the post-compliance pollutant loadings. EPA also estimates that the number of immediate receiving waters with human health water quality standards exceedances, primarily driven by total arsenic and total thallium concentrations, would be reduced by up to 14 percent for Option 3a, up to 15 percent for Option 3b, up to 18 percent for Option 3, and up to 41 percent for Option 4a.

Selenium was one of the primary pollutants identified in the literature as causing documented environmental impacts to fish and wildlife. EPA calculates that total selenium receiving water concentrations would be reduced by 33 percent on average under Option 3a, 36 percent on average under Option 3b, 48 percent on average under Option 3, and 60 percent on average under Option 4a. This would reduce the number of immediate receiving waters exceeding the freshwater chronic criteria for selenium by 38 percent under Option 3a, 40 percent under Option 3b, 55 percent under Option 3, and 67 percent under Option 4a. EPA estimates that up to 3,643 river miles (Option 3a), 3,862 river miles (Option 3b), 4,830 river miles (Option 3), and 6,633 river miles (Option 4a) downstream from steam electric discharges would no longer exceed aquatic life and human health NRWQC or MCL standards under the post-compliance pollutant loadings.

The preferred options would both reduce ground water contamination levels and improve the availability of ground water resources by reducing the future leaching of pollutants from steam electric impoundments to groundwater aquifers. Section XIV provides additional details on the benefits analysis of these ground water improvements.

*B. Reduced Impacts to Wildlife*

EPA calculates that the number of immediate receiving waterbodies with potential impacts to wildlife would be

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reduced by up to 23 percent under Option 3a, up to 24 percent under Option 3b, up to 30 percent under Option 3, and up to 51 percent under Option 4a. EPA developed the receiving waters wildlife model to quantify the impacts to wildlife that consume fish exposed to steam electric discharges. EPA selected minks and eagles as representative indicator species to evaluate the impact discharges of the evaluated wastestreams posed to birds and mammals that consume fish. EPA selected minks and eagles based on their national population distribution and the fact that a majority of their diet is comprised of fish. EPA modeled fish tissue concentrations for the immediate and downstream receiving waters and compared those concentrations to no effect hazard concentrations (NEHC) benchmarks developed by the U.S. Geological Survey (USGS) that indicate potential impacts to piscivorous (i.e., fish eating) wildlife. The NEHC benchmarks developed by the USGS are based on "no observed adverse effect levels" (NOAELs), which were derived from adult dietary exposure or tissue concentration studies and based primarily on reproductive endpoints.

EPA determined that combustion wastewater discharges into lakes pose the greatest risk to piscivorous wildlife, with approximately 78 percent of lakes compared to 39 percent of rivers exceeding a NEHC benchmark for minks or eagles under baseline pollutant loadings. Mercury and selenium, and to a lesser extent cadmium and zinc, were the primary pollutants with greatest number of receiving waters with wildlife NEHC benchmark exceedances. EPA estimates that the preferred options would reduce the number of immediate receiving waters exceeding the mercury NEHC for minks and eagles by up to 24 percent under Option 3a, up to 26 percent under Option 3b, up to 33 percent under Option 3, and up to 52 percent under Option 4a. For selenium, EPA estimates that the number of immediate receiving waters exceeding the selenium NEHC would be reduced by up to 29 percent under Option 3a, up to 31 percent under Option 3b, up to 42 percent under Option 3, and up to 56 percent under Option 4a. This indicates that the preferred options would reduce the bioaccumulative impact of the evaluated wastestreams in the broader ecosystem. EPA estimates that up to 4,135 river miles (Option 3a), up to 4,360 river miles (Option 3b), up to 5,300 river miles (Option 3), and up to 8,206 river miles (Option 4a) downstream from steam electric discharges would no longer exceed a NEHC benchmark for minks or eagles under the post-compliance pollutant loadings.

In addition, EPA estimates that the upgrades to water quality (i.e., reductions in aquatic life NRWQC exceedances) discussed above would improve aquatic and wildlife habitats in the immediate and downstream receiving waters from steam electric discharges. EPA determined that these water quality and habitat improvements would enhance efforts to protect threatened and endangered species. EPA identified eight species with a high vulnerability to changes in water quality whose recovery would be expected to be enhanced by the post-compliance pollutant loading reductions associated with the preferred options.

*C. Reduced Human Health Cancer Risk*

EPA estimates that reductions in arsenic loadings from the preferred options would result in a reduction in potential cancer risks to humans that consume fish exposed to discharges of the evaluated wastestreams. The human health model calculates the potential cancer risk for select age groups and consumption categories (i.e., child and adult recreational fishers and child and adult subsistence fishers) based on assumptions of arsenic bioaccumulation in fish exposed to discharges of the evaluated wastestreams. Under baseline pollutant loadings, EPA determined that up to 9 percent of immediate receiving waters contain fish contaminated with inorganic arsenic that would present cancer risks above the 1-in-a-million threshold for one or more of the cohorts evaluated. EPA determined that, depending on the cohort, immediate receiving waters with cancer risks above the 1-in-a-million threshold would be reduced by up to 40 percent (Option 3a), up to 60 percent (Option 3b and Option 3), and up to 80 percent (Option 4a) under post-compliance loadings. In addition, EPA estimates that up to 266 river miles, depending on the cohort, downstream from the steam electric discharges contain fish contaminated with inorganic arsenic that would present cancer risks above the 1-in-a-million threshold. Under the post-compliance pollutant loadings associated with the preferred options, EPA estimates that up to 111 river miles (Option 3a), up to 116 river miles (Option 3b), up to 133 river miles (Option 3), and up to 169 river miles (Option 4a) downstream from steam electric discharges would no longer contain fish contaminated with inorganic arsenic that would present cancer risks above the 1-in-a-million threshold for adult subsistence fishers.

*D. Reduced Threat of Non-Cancer Human Health Effects*

Exposure to metals poses risk of systemic and other effects to humans, including effects on the circulatory, respiratory, or digestive systems and neurological and developmental effects. The preferred options are estimated to reduce the number of receiving waters with potential to cause non-cancer health effects in humans who consume fish exposed to discharges of the evaluated wastestreams. The human health model calculates the number of immediate receiving waters with the potential to cause non-cancer health effects in select age groups and consumption categories (i.e., child and adult recreational fishers and child and adult subsistence fishers) based on assumptions of metal bioaccumulation in fish exposed to discharges of the evaluated wastestreams. Depending on the cohort, EPA calculates that exceedances of non-cancer reference doses from the consumption of fish would decrease in up to 19 percent of surface waters (Option 3a), up to 21 percent of surface waters (Option 3b), up to 26 percent of surface waters (Option 3), and up to 53 percent of surface waters (Option 4a) immediately receiving discharges of the evaluated wastestreams. Non-cancer risks are driven by mercury (as methylmercury), total thallium, and total selenium, and to a lesser degree, total cadmium pollutant loadings. Under baseline pollutant loadings, the average daily dose from the consumption of fish in up to 65 percent of immediate receiving waters exceeds the non-cancer reference dose for mercury depending on the cohort. Under post-compliance loadings, exceedances of the non-cancer mercury reference dose would decrease in up to 21 percent (Option 3a), up to 22 percent (Option 3b), up to 29 percent (Option 3), and up to 49 percent (Option 4a) of immediate receiving waters, depending on the cohort. In addition, exceedances of total thallium and total selenium non-cancer reference doses would decrease in up to 14 and 50 percent of immediate receiving waters (Option 3a and Option 3b), up to 18 and 69 percent of immediate receiving waters (Option 3), and up to 43 and 77 percent of immediate receiving waters (Option 4a), respectively. EPA also estimates that, under the post-compliance pollutant loadings, exceedances of non-cancer reference doses from the consumption of fish would decrease in up to 4,084 river miles downstream (Option 3a), up to 4,316 river miles downstream (Option 3b), up to 5,400 river miles downstream

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(Option 3), and up to 8,087 river miles downstream (Option 4a) for one or more of the cohorts.

In addition to the assessment of non-cancer reference dose exceedances described above, EPA also evaluated the adverse health effects to children who consume fish contaminated with lead from combustion wastewater. EPA estimated the reduction in lead exposure to pre-school children via consumption of contaminated fish tissue and determined that the preferred options would reduce the associated intelligence quotient (IQ) loss among children who live in recreational angler and subsistence fisher households. The preferred options would also be expected to reduce the incidence of other health effects associated with lead exposure among children, including slowed or decayed growth, delinquent and anti-social behavior, metabolic effects, impaired hemesynthesis, anemia, impaired hearing, and cancer. The preferred options would also reduce the IQ loss among children exposed *in-utero* to mercury from maternal fish consumption in populations exposed to immediate and downstream receiving waters from steam electric discharges. Section XIV.B.1.a provides additional details on the benefits analysis of these reduced IQ losses.

EPA expects that the preferred options would result in additional non-cancer human health effects beyond those described above, including reduced health hazards due to exposure to contaminants in waters that are used for recreational purposes (e.g., swimming).

*E. Reduced Nutrient Impacts*

The primary concern with nutrients in steam electric discharges is the potential for adverse nutrient impacts to occur in water-bodies that receive discharges from multiple plants. Nine percent of surface waters receiving steam electric wastewater discharges are impaired for nutrients. While the current concentration of nitrogen present in steam electric discharges from any individual power plant is relatively low, the total nitrogen loadings from a single plant can be significant due to large wastewater discharge flow rates. Total nutrient loadings from multiple power plants is especially a concern on water bodies that are nutrient impaired or in watersheds that contribute to downstream nutrient problems.

Excessive nutrient loadings to receiving waters can significantly affect the ecological stability of freshwater and saltwater aquatic systems. Nutrient over-enrichment of surface waters can stimulate excessive plant growth that can obstruct sunlight penetration and increase turbidity, which can result in the death of bottom-dwelling aquatic plants. Higher nutrient loadings from steam electric discharges could result in the eutrophication of waters and the formation of hazardous algal blooms. An additional concern with nutrients in steam electric discharges is the potential for the total nitrogen loadings from plants to increase in the future as air pollution limits become stricter and the use of air pollution controls increases.

EPA projects that the preferred options would reduce total nutrient loadings by 39 percent (Option 3a), by 41 percent (Option 3b), by 53 percent (Option 3), and by 66 percent (Option 4a) and improve overall water quality. EPA used the SPARROW (SPAtially Referenced Regressions On Watershed attributes) model to calculate immediate receiving water concentrations under baseline conditions and under five of the regulatory options discussed in Section VIII of this preamble (Options 1, 2, 3, 4, and 5) to analyze benefits related to improvements in water quality. EPA used these concentrations to develop sub-indices for a water quality index (WQI), a value that translates water quality measurements, gathered for multiple parameters that represent various aspects of water quality, into a single numerical indicator. Section XIV provides additional details on the water quality benefits analysis of nutrient reductions.

*F. Unquantified Environmental and Human Health Improvements*

The above environmental assessment focused on the quantification of environmental improvements within rivers and lakes from post-compliance pollutant loading reductions for toxic metals and excessive nutrients. While extensive, the environmental improvements quantified do not encompass the full range of improvements anticipated to result from the preferred options simply because some of the improvements have no method for measuring a quantifiable or monetizable improvement. EPA expects post-compliance pollutant loading reductions from the preferred options to result in much greater improvements to wildlife, human health and environmental health by reducing the:

- Loadings of bioaccumulative metals to the broader ecosystem resulting in the reduction of long-term exposures and sublethal ecological effects;
- Sublethal chronic effects of toxic metals on aquatic life not captured by the NRWQC;
- Impacts to aquatic and aquatic-dependant wildlife population diversity and community structures;
- Exposure of wildlife to pollutants through direct contact with combustion residuals impoundments and constructed wetlands built as treatment systems at steam electric power plants;
- Adverse health effects in adults resulting from exposure to lead from consumption of contaminated fish tissue; and
- Potential for the formation of hazardous algal blooms.

Data limitations prevented appropriately modeling the scale and complexity of the ecosystem processes potentially impacted by combustion wastewater, resulting in the inability to quantify the improvements listed. However, documented case studies in the literature reinforce that these impacts are common in the environments surrounding steam electric power plants and fully support the conclusion that reducing pollutant loadings will improve overall environmental, human health and wildlife health.

Although the Environmental Assessment quantifies impacts to wildlife that consume fish contaminated with metals from combustion wastewater, it does not capture the full range of exposure pathways through which bioaccumulative metals can enter the surrounding food web. Wildlife can encounter toxic bioaccumulative metals from discharges of the evaluated wastestreams from a variety of exposure pathways such as direct exposure, drinking water, consumption of contaminated vegetation, and consumption of contaminated prey other than fish. Therefore, the quantified improvements underestimate the complete loadings of bioaccumulative metals that can impact wildlife in the ecosystem. EPA anticipates that the post-compliance pollutant loading reductions associated with the preferred options would lower the total amount of toxic bioaccumulative metals entering the food web near steam electric power plants.

EPA also expects the estimated reduction in pollutant loadings to lower the occurrence of sublethal effects associated with many of the pollutants in combustion wastewater that may not be captured by comparisons with NRWQC for aquatic life. Chronic effects such as changes in metabolic rates, decreased growth rates, changes in morphology (e.g., fin erosion, oral deformities), and behavior (e.g., swimming ability, ability to catch prey, ability to escape from predators) that

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can negatively affect long-term survival, are well documented in the literature in environments near steam electric power plants. Reductions in organism survival rates from the chronic effects such as abnormalities can alter interspecies relationships (e.g., declines in the abundance or quality of prey) and prolong ecosystem recovery. However, these effects were not quantified in the environmental assessment and improvements to wildlife health and survival from the preferred options are, therefore, underestimated. EPA was unable to quantify changes to aquatic and wildlife population diversity and community dynamics; however, population effects (i.e., decline in number and type of organisms present) attributed to exposure to combustion wastewater are well documented in the literature. Changes in aquatic populations can alter the structure of aquatic communities and cause cascading effects within the food web that result in long-term impacts to ecosystem dynamics. EPA expects that post-compliance pollutant loading reductions associated with the preferred options would lower the stressors that can cause alterations in population and community dynamics and improve the overall function of ecosystems surrounding steam electric power plants, as well as help resolve issues faced in other national ecosystem protection programs such as the Great Lakes program, the National Estuaries program and the 303(d) impaired waters program.

EPA anticipates that the expected post-compliance pollutant loading reductions associated with the preferred options would also decrease the environmental impacts to wildlife exposed to pollutants through direct contact with combustion residuals impoundments and constructed wetlands at steam electric power plants. Documented case studies demonstrate that wildlife living in close proximity to combustion residuals impoundments exhibit elevated levels of arsenic, cadmium, chromium, lead, mercury, selenium, strontium, and vanadium. Multiple studies have linked attractive nuisance areas (contaminated areas at a steam electric power plant, such as combustion wastewater surface impoundments, that are attractive to wildlife (place for nesting)) to diminished reproductive success. EPA expects that the post-compliance pollutant loadings would decrease the exposure of wildlife populations to toxic pollutants and reduce the risks for impacts on reproductive success.

### *G. Other Secondary Improvements*

EPA anticipates that other secondary, or ancillary, improvements would occur to other resources that are associated directly or indirectly as a result of the preferred options. These would include aesthetic and recreational improvements, reduced economic impacts such as clean up and treatment costs in response to contamination or impoundment failures, reduced injury associated with pond failures, reduced water usage and reduced air emissions. Section XIV provides additional details on the benefits of these other secondary improvements.

## XIV. Benefit Analysis

This section summarizes EPA's estimates of the national environmental benefits expected to result from reduction in pollutant discharges described in Section IX and the resultant environmental effects summarized in Section XIII. The *Benefit and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA) report provides additional details on benefits methodologies and analysis, including uncertainties and limitations.

### *A. Categories of Benefits Analyzed*

Table XIV–1 summarizes benefit categories associated with this proposed rule and notes which categories EPA was able to quantify and monetize. Analyzed benefits fall within six broad categories: human health benefits, ecological conditions and recreational use benefits from surface water quality improvements, market and productivity benefits, air-related benefits, groundwater quality benefits, and water withdrawal benefits. Within these broad categories, EPA was able to assess benefits with varying degrees of completeness and rigor. Where possible, EPA quantified the expected effects and estimated monetary values. However, data limitations and gaps in the understanding of how society values certain water quality changes prevent EPA from quantifying and/or monetizing some benefit categories.

TABLE XIV–1—BENEFIT CATEGORIES ASSOCIATED WITH PROPOSED ELGS

| Benefit category | Quantified and monetized | Quantified but not monetized | Neither quantified nor monetized |
|---|---|---|---|
| **1. Human Health Benefits from Surface Water Quality Improvements** | | | |
| Reduced incidence of cancer from arsenic exposure via fish consumption | X | | |
| Reduced non-cancer adverse health effects (e.g., reproductive, immunological, neurological, circulatory, or respiratory toxicity) due to exposure to arsenic from fish consumption | | X | |
| Reduced IQ loss in children from lead exposure via fish consumption | X | | |
| Reduced need for specialized education for children from lead exposure via fish consumption | X | | |
| Reduced adverse health effects in adults from exposure to lead from fish consumption | | | X |
| Reduced in-utero mercury exposure via maternal fish consumption | X | | |
| Reduced health hazards from exposure to pollutants in waters used recreationally (e.g., swimming) | | | X |
| **2. Ecological Conditions and Recreational Use Benefits from Surface Water Quality Improvements** | | | |
| Benefits from improvements in surface water quality, including: improved aquatic and wildlife habitat; enhanced water-based recreation, including fishing, swimming, boating, and near-water activities; increased aesthetic benefits, such as enhancement of adjoining site amenities (e.g., residing, working, traveling, and owning property near the water[a]; and non-use value (i.e., existence, option, and bequest value from improved ecosystem health)[a] | X | | |

TABLE XIV–1—BENEFIT CATEGORIES ASSOCIATED WITH PROPOSED ELGS—Continued

| Benefit category | Quantified and monetized | Quantified but not monetized | Neither quantified nor monetized |
|---|---|---|---|
| Benefits from improved protection of threatened and endangered species | X | | |
| Reduced sediment contamination | | | X |
| **3. Groundwater Quality Benefits** | | | |
| Reduced groundwater contamination | X | | |
| **4. Market and Productivity Benefits** | | | |
| Reduced impoundment failures (monetized benefits include avoided cleanup costs and environmental damages; non-quantified benefits include avoided injury) | X | | |
| Reduced water treatment costs for municipal drinking water, irrigation water, and industrial process | | | X |
| Improved commercial fisheries yields | | | X |
| Increased tourism and participation in water-based recreation | | | X |
| Increased property values from water quality improvements | | | X |
| **5. Air-Related Benefits** | | | |
| Reduced mortality from exposure to $NO_X$, $SO_2$ and particulate matter ($PM_{2.5}$) | X | | |
| Avoided climate change impacts from $CO_2$ emissions | X | | |
| **6. Benefits from Reduced Water Withdrawals** | | | |
| Increased availability of groundwater resources | X | | |

a. These values are implicit in the total willingness to pay (WTP) for water quality improvements.

The following section discusses EPA's analysis of the benefits that the Agency was able to quantify and monetize (identified in the second column of Table XIV–1). The proposed rule would also result in additional benefits that the Agency was not able to monetize. See the Benefits and Cost Analysis Document for information about these non-monetized benefits.

EPA estimated benefits for five of the eight regulatory options discussed in this preamble (Options 1, 2, 3, 4, and 5). EPA did not estimate the benefits of Options 3a, 3b and 4a. However, EPA used its understanding of the wastestreams and treatment technologies for these options, along with projections of pollutant reductions for all eight options, to estimate total monetized benefits for Options 3a, 3b, and 4a. However, EPA is less confident that this approach would yield reasonable estimates if applied to the individual categories of benefits (water quality, air emissions, avoided impoundment failure cleanup costs, etc) and so has not done so. For these more granular benefits categories, estimates are provided only for Options 1, 2, 3, 4, and 5. Again, these can serve as upper and lower bounds for the individual categories of benefits of Options 3a, 3b, and 4a. Specifically, monetized benefits for Options 3a and 3b are likely to be between those for Options 2 and 3. Similarly, monetized benefits for Option 4a are likely to be between those for Options 3 and 4.

*B. Quantification and Monetization of Benefits*

1. Human Health Benefits From Surface Water Quality Improvements

Reduced pollutant discharges from steam electric plants generate human health benefits in a number of ways. Pollutants commonly discharged in Steam Electric plant wastewater streams include conventional and toxic pollutants such as arsenic, cadmium, chromium, copper, lead, mercury, selenium, and zinc (steam electric pollutants). Exposure to these pollutants via consumption of fish from affected waterways can cause a wide variety of adverse health effects, including cancer, kidney damage, nervous system damage, fatigue, irritability, liver damage, circulatory damage, vomiting, diarrhea, brain damage, IQ loss, and many others. Because the proposed ELGs would reduce discharges of steam electric pollutants into receiving waterways and downstream areas, they are likely to result in decreased incidences of associated illnesses.

Due to data limitations and uncertainties, EPA is able to monetize only a small subset of the health benefits associated with decreased pollutant discharges from steam electric plants. EPA analyzed the following measures of human health-related benefits: reduced cancer risk due to arsenic exposure from fish consumption, reduced lead-related IQ loss in children from fish consumption, and reduced mercury-related IQ loss in children exposed in-utero due to maternal fish consumption. EPA monetized these human health benefits by estimating the change in the expected number of individuals experiencing adverse human health effects in the populations exposed to steam electric discharges under various regulatory options and valuing these changes using a variety of nonmarket approaches (e.g., cost of illness).

a. Monetized Human Health Benefits

EPA quantified and monetized the following four categories of human health benefits:

- *Benefits from Reduced Incidence of Cancer from Arsenic Exposure via Fish Consumption.* EPA assessed changes in the incidence of cancer cases from consumption of arsenic in the tissue of fish caught in waters affected by steam electric plant discharges. For the baseline and each regulatory option, EPA estimated cancer risk from the consumption of arsenic-contaminated fish for recreational and subsistence anglers and their families. EPA used data on the populations living within 100 miles of affected waterbodies, state-specific average fishing rates, presence of fish consumption advisories, the availability of substitute fishing

locations, and average household size to estimate the exposed population for each steam electric facility. To identify the change in number of cancer cases caused by arsenic in this population, EPA used a cancer slope factor (CSF) from EPA's Integrated Risk Information System (IRIS) of 1.5 per mg/kg-day and different fish consumption rates for recreational and subsistence anglers and age cohorts. The Agency valued changes in incidence of cancer cases using a value of a statistical life (VSL) of $8.0 million (2010$), with projections adjusted to account for income growth. This estimate does not include estimates of willingness to pay (WTP) to avoid illness prior to death.

• *Benefits from Reduced IQ Loss in Children from Lead Exposure via Fish Consumption.* Children's rapid rate of development makes them more susceptible to neurobehavioral effects from lead exposure. The neurobehavioral effects on children from lead exposure include hyperactivity, behavioral and attention difficulties, delayed mental development, and motor and perceptual skill deficits. EPA assessed benefits of reduced lead exposure from consumption of contaminated fish tissue and the associated IQ loss among children aged 0 to 7. EPA estimated blood-lead levels using EPA's Integrated Exposure, Uptake, and Biokinetic (IEUBK) Model based on daily lead ingestion rates among children from birth to the seventh birthday. Based on blood lead concentrations for children in recreational and subsistence anglers' families, EPA assessed neurobehavioral effects on children using an established dose response relationship between blood lead concentrations and IQ loss. Avoided neurological and cognitive damages are expressed as an increase in overall IQ points in the exposed population. EPA monetized the estimated changes in IQ scores based on the impact of additional IQ points on individuals' future earnings. EPA assumed that each IQ point is worth between $1,156 (following Schwarz (1994) and discounting future earnings at 7 percent) and $13,651 (following Salkever (1995) and discounting future earnings at 3 percent).

• *Benefits from Reduced Need for Specialized Education for Children from Lead Exposure via Fish Consumption.* EPA also quantified the reduced incidences of especially high blood-lead levels (above 20 mg/dL) and low IQ scores (<70, or two standard deviations below the mean), and monetized the avoided costs associated with compensatory education that an individual would otherwise need. For this analysis, EPA used the IEUBK model to estimate how many children in the exposed population would have blood lead concentrations above 20 mg/dL, and assumed that 20 percent of those children would have IQ scores below 70. Based on education cost data from the United States Department of Education, EPA assumed that the incremental cost of special education for these individuals and ages 7 through 18 would be approximately $157,000 per child at 3 percent discount rate, and $125,500 per child at 7 percent discount rate.

• *Benefits of Reduced In-utero Mercury Exposure via Maternal Fish Consumption.* Mercury is a highly toxic pollutant that presents serious health risks to adults and children, even in very small doses. Health effects can include damage to the brain, kidneys, heart, and especially nervous system. These impacts are particularly harmful for children, who can experience profound and permanent developmental and neurological delays as a result of exposure in-utero. EPA estimated the IQ-related benefits associated with reduced in-utero mercury exposure from maternal fish consumption in exposed populations. EPA used data on the populations living within 100 miles of affected waterbodies, state-specific average fishing rates, presence of fish consumption advisories, the availability of substitute fishing locations, average household size, the number of women of childbearing age, and state-specific birth rates to estimate the number of births in the exposed population. Based on a dose-response function developed by Axelrad et al. (2007), EPA assigned a 0.18 point IQ loss for each 1 ppm increase in maternal hair mercury. To translate the daily mercury ingestion rate by women of childbearing age in the exposed populations to hair mercury concentrations, EPA used a conversion rate derived by Swartout and Rice (2000). Including decreased lifetime earnings and avoided education costs, EPA assumed that the value of an IQ point is between $1,156 and $13,651 over the life of each individual.

Table XIV–2 summarizes monetized human health benefits associated with five of the eight regulatory options considered in this proposed rule using 3 percent and 7 percent discount rates. As mentioned above, EPA did not monetize the human health benefits associated with Options 3a, 3b and 4a. EPA expects the benefits of Option 4a to be between those of Options 3 and 4.

TABLE XIV–2—ANNUALIZED HUMAN HEALTH BENEFITS

[million 2010$] [c]

| Human health benefit category | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|---|---|---|---|---|---|
| **3% Discount Rate** | | | | | |
| Benefits from Reduced Incidence of Cancer from Arsenic Exposure via Fish Consumption. | <$0.1 | <$0.1 | $0.1 | $0.2 | $0.2 |
| Benefits from Reduced IQ Loss in Children from Lead Exposure via Fish Consumption [a]. | $0.1 ($0.1 to $0.1) | $0.1 ($0.1 to $0.1) | $2.7 ($2.2 to $3.2) | $6.7 ($5.6 to $7.9) | $6.7 ($6.5 to $7.9) |

TABLE XIV–2—ANNUALIZED HUMAN HEALTH BENEFITS—Continued

[million 2010$] [c]

| Human health benefit category | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|---|---|---|---|---|---|
| Benefits from Reduced Need for Specialized Education for Children from Lead Exposure via Fish Consumption. | <$0.1 (<$0.1 to <$0.1). | <$0.1 (<$0.1 to <$0.1). | <$0.1 (<$0.1 to <$0.1). | $0.1 ($0.1 to $0.1) ..... | $0.1 ($0.1 to $0.1) |
| Benefits of Reduced In-utero Mercury Exposure via Maternal Fish Consumption [a]. | $3.8 ($3.2 to $4.5) .... | $3.9 ($3.2 to $4.6) ..... | $5.0 ($4.1 to $5.8) .... | $10.2 ($8.4 to $12.1) | $10.2 ($8.4 to $12/1) |
| Total Human Health Benefits [b]. | $3.9 ($3.21 to $4.59) | $4.0 ($3.28 to $4.69) | $7.7 ($6.4 to $9.11) .. | $17. ($14.2 to $20.2) | $17. ($14.2 to $20.2) |
| **7% Discount Rate** | | | | | |
| Benefits from Reduced Incidence of Cancer from Arsenic Exposure via Fish Consumption. | <$0.1 ..... | <$0.1 ..... | $0.1 ..... | $0.1 ..... | $0.1 |
| Benefits from Reduced IQ Loss in Children from Lead Exposure via Fish Consumption [a]. | <$0.1 (<$0.1 to <$0.1). | <$0.1 (<$0.1 to <$0.1). | $0.2 ($0.2 to $0.3) ..... | $0.6 ($0.4 to $0.8) .... | $0.6 ($0.4 to $0.8) |
| Benefits from Reduced Need for Specialized Education for Children from Lead Exposure via Fish Consumption. | <$0.1 (<$0.1 to <$0.1). | <$0.1 (<$0.1 to <$0.1). | <$0.1 (<$0.1 to <$0.1). | <$0.1 (<$0.1 to <$0.1). | <$0.1 (<$0.1 to <$0.1) |
| Benefits of Reduced In-utero Mercury Exposure via Maternal Fish Consumption [a]. | $0.3 ($0.2 to $0.5) .... | $0.4 ($0.2 to $0.5) ..... | $0.4 ($0.3 to $0.6) .... | $0.9 ($0.6 to $1.2) .... | $0.9 ($0.6 to $1.2) |
| Total Human Health Benefits [b]. | $0.4 ($0.2 to $0.5) .... | $0.4 ($0.2 to $0.5) ..... | $0.7 ($0.5 to $1.0) .... | $1.6 ($1.1 to $2.1) .... | $1.6 ($1.1 to $2.1) |

[a] Low end assumes that the loss of one IQ point results in the loss of 1.76% of lifetime earnings (following Schwartz, 1994); high end assumes that the loss of one IQ point results in the loss of 2.38% of lifetime earnings (following Salkever, 1995).

[b] Totals may not add up due to independent rounding.

[c] EPA did not estimate the benefits of Options 3a, 3b and 4a. EPA expects the benefits of Option 4a to be between those of Options 3 and 4.

b. Reduced Exceedances of Health-Based AWQC

EPA expects that additional health benefits will arise from reduced discharges of steam electric pollutants; however, monetary valuation of these other health benefits is not currently possible due to lack of data on a dose-response relationship between pollutant ingestion rate and potential adverse health effects. To provide an additional measure of the potential health benefits of the proposed ELGs, EPA estimated the effect of steam electric plant discharges on the occurrence of pollutant concentrations in affected waterways that exceed human health-based ambient water quality criteria (AWQCs).[84] Pollutant concentrations in excess of these values indicate potential risks to human health. This analysis and its findings are not additive to the preceding analyses of change in cancer or lead-related health risks but are another way of quantitatively characterizing possible benefit categories.

EPA estimates that in-stream concentrations of steam electric pollutants (i.e., arsenic, cadmium, chromium, copper, lead, mercury, nickel, selenium, thallium, and zinc) exceed human health criteria for consumption of water and organisms for at least one pollutant in 146 receiving reaches nationwide in the baseline. Depending on the regulatory option, EPA expects that the proposed rule would eliminate the occurrence of concentrations in excess of human health criteria for consumption of water and organisms for 0 to 98 of the contaminated reaches, and reduce the number of exceedances in 9 to 27 reaches. Option 3 is estimated to

[84] Including AWQCs for the protection of human health through consumption of organisms and water.

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eliminate exceedances in 27 receiving reaches, out of the 146 receiving reaches with exceedances in the baseline, while Option 4 is estimated to reduce exceedances in 98 reaches and eliminate exceedances altogether in 24 of those reaches. EPA did not quantitatively analyze the change in exceedances for Options 3a, 3b and 4a. However, EPA expects the effects of Option 4a to be between those of Options 3 and 4 (i.e., reduce or eliminate exceedances in between 27 and 98 receiving reaches).

2. Improved Ecological Conditions and Recreational Use Benefits From Surface Water Quality Improvements

EPA expects the proposed ELGs to provide ecological benefits by improving ecosystems (aquatic and terrestrial) affected by the electric power industry's effluent discharges. Benefits associated with changes in aquatic life include restoration of sensitive species, recovery of diseased species, changes in taste-and odor-producing algae, changes in dissolved oxygen (DO), increased assimilative capacity of affected waterways, and improved related recreational activities. Activities such as fishing, swimming, wildlife viewing, camping, waterfowl hunting, and boating may be enhanced when risks to aquatic life and perceivable water quality effects associated with pollutants are reduced. The magnitude of these benefits depends on the regulatory option.

EPA was able to monetize several categories of ecological benefits associated with this proposed rule, including recreational use and nonuse (i.e., existence, bequest, and altruistic) benefits from improvements in the health of aquatic environments, and nonuse benefits from increased populations of threatened and endangered species. As shown in Table XIV–1, the Agency quantified and monetized two main benefit subcategories, discussed below: (1) Benefits from improvements in surface water quality, and (2) benefits from improved protection of threatened and endangered (T&E) species.

a. Improvements in Surface Water Quality

EPA expects these proposed ELGs to improve aquatic species habitats by reducing concentrations of toxic contaminants such as arsenic, cadmium, chromium, lead, mercury, nickel, selenium, and zinc in water. The rule is also expected to reduce nitrogen and phosphorus concentrations. These improvements would be expected to enhance the quality and value of water-based recreation. For example, some of the streams that were not usable for recreation under the baseline discharge conditions may become usable following implementation of the rule, thereby expanding options for recreational users. Streams that have been used for recreation under the baseline conditions can become more attractive for users by making recreational trips even more enjoyable. Individuals may also take trips more frequently if they enjoy their recreational activities more. These proposed ELGs are also expected to generate nonuse benefits from bequest, altruism, and existence motivations. Individuals may value the knowledge that water quality is being maintained, ecosystems are being protected, and species populations are healthy, independently of their use.

To calculate baseline and post-compliance water quality, EPA utilized a water quality index (WQI) that translates water quality measurements, gathered for multiple parameters that are indicative of various aspects of water quality, into a single numerical indicator that reflects achievement of quality consistent with certain uses. The WQI provides the link between specific pollutant levels, as reflected in individual parameters, and the presence of aquatic species and suitability for particular recreational uses. Traditionally, WQIs are based on conventional pollutants (e.g., TSS, BOD, and fecal coliform) and nutrients (nitrogen and phosphorus). To account for water quality improvements resulting from reductions in toxic pollutants, EPA expanded the set of WQI parameters to include metals. The metals sub-index follows an approach developed by the Canadian Council of Ministers of the Environment (CCME) and uses the number of AWQC exceedances for a given waterbody in the baseline and/or under a given regulatory option.[85] EPA assigned all parameters in the index an equal weight of 1/7th following other studies that use equal weights for all index parameters (Cude 2001, CCME 2001, and Carruthers and Wazniak 2003).

EPA calculated baseline and post compliance WQI values for reaches affected by steam electric plant discharges. Baseline and post compliance water quality data were taken from several sources including USGS's SPARROW model, EPA's Risk-Screening Environmental Indicators (RSEI) model, EPA's STORET data warehouse, and estimated in-stream concentrations of steam electric pollutants. These sources provide water quality for stream networks defined according to the medium-resolution NHD or RF1. EPA conducted the benefits analysis at the level of RF1 reaches and mapped NHD data to the appropriate RF1, as needed, depending on the data source. EPA estimates that 3,945 reach miles would improve under Option 1 for existing sources, 12,683 miles under Option 2, 15,682 miles under Option 3, 22,447 reach miles under Option 4, and 22,441 reach miles under Option 5. EPA did not estimate the number of reach miles that would improve under Option 4a but expects improvements to be between those of Options 3 and 4 (i.e., between 15,682 and 22,447 reach miles).

EPA estimated monetized benefit values using a meta-regression of surface water valuation studies originally developed for the Effluent Guidelines and Standards for the Construction and Development Point Source Category (U.S. EPA, 2009). EPA used two benefit functions for each reach; one for households within a 100-mile radius of the reach that may have user values and one for nonuser households, located in the same state as the reach, but outside the 100-mile radius. Each benefit function was estimated for the years between 2014 and 2040, although benefits start accruing in 2017 when certain plants would be expected to start installing control technologies under this proposal (i.e., no benefits are assumed for 2014–2016). EPA estimated total benefits for each group—users and nonusers—as follows:

- The Agency first estimated annual household WTP values for a given reach and year using the meta-analysis regression. WTP values are a function of (1) reach-specific baseline and change in water quality values in a given year and (2) median household income values estimated for a given state or buffer zone in that year. For this analysis, two benefit functions were used for each reach in a given year; one for households that may have user values (households located within 100 miles of the reach) and one for nonuser households (households located with the same state as the reach, but outside the 100-mile buffer).
- To estimate total WTP values, the Agency multiplied annual household WTP values by the percent of total reach miles within the state or buffer and the total number of households within the state or buffer for a given year.
- EPA then discounted total WTP values to 2014, the expected

[85] There may be between 0 and 8 exceedances per waterbody (freshwater chronic AWQC values are available for arsenic, cadmium, chromium, lead, mercury, nickel, selenium, and zinc).

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promulgation year of the rule, and annualized them using a 3 and 7 percent discount rate.

A challenge for meta-analysis is developing a framework that both controls for differences in studies and can be used for meaningfully predicting benefits associated with regulatory options. In earlier benefits estimation for effluent guidelines, EPA often relied on the Carson and Mitchell (1993) water quality values. These values come from a survey that was one of the first major stated preference efforts, fielded in the early 1980s. The study reported values for all of the nation's waters, using the same WQI that is used in the meta-analysis. When EPA used the Carson and Mitchell values, the Agency was able to tailor its benefits estimates to its regulations in two important dimensions: the level of water quality improvement, and the percent of the nation's waters being improved. EPA is basing this benefits analysis on the meta-analysis because stated preference methodology and practices have advanced considerably since the Carson and Mitchell study (although methodological issues continue to be debated in the stated preference literature), more studies have been conducted, and changes in individuals' preferences and income may well result in changing water quality values.

A trade-off, however, in using the meta-analysis is the difficulty in representing the percent of the nation's waters that are being improved, in addition to combining the results of studies encompassing a variety of water quality improvements, geographic scales, and resource characteristics that has led to both expected results and results that are counterintuitive. To provide perspective on these different approaches to measure water quality improvement benefits, EPA is also reporting the water quality values obtained by applying the Carson and Mitchell values. In 2011 dollars, using a 3 percent discount rate, these values are: for Option 1, $0.5 million; for Option 2, $2.9 million; for Option 3, $4.5 million; for Option 4, $12.9 million; and for Option 5, $12.7 million. EPA requests comment on its reliance on the meta-analysis values rather than the Carson and Mitchell values (or some other values) as the basis for estimating water quality benefits of the proposed rule. Commenters should address methodological strengths and weaknesses of any suggested approach, and explain the basis for their recommendation.

b. Benefits to Threatened and Endangered (T&E) Species

To assess the potential for impacts on threatened and endangered (T&E) species (both aquatic and terrestrial), EPA constructed a database of waterbodies currently exceeding wildlife-based AWQC but expected to have no wildlife AWQC exceedances as a result of the proposed ELGs. EPA then assessed the overlap between this geographic database and the known locations of approximately 530 T&E species. Once species overlapping waterbodies of interest were identified, EPA examined their life history traits to categorize species by the potential for population impacts likely to occur as a result of changes in water quality. T&E species with high probability of life-history effects were further screened to identify those species for which water quality was identified as a factor for listing under the Endangered Species Act (ESA) or as a limiting factor within species recovery plans. Because of this analysis, EPA identified seven fish species and one dragonfly species that may experience changes in population growth rates as a result of the proposed ELGs. EPA did not identify data sufficient to explicitly model the effects of changes in water quality on population growth rates for these species. Therefore, to estimate total population increases resulting from the proposed ELGs, EPA assumed minimal increases in population size of 0.5, 1, or 1.5 percent. To estimate monetary benefits to T&E species, EPA weighted these population growth estimates by the percent of reaches used by T&E species that are expected to meet wildlife-based AWQC because of the proposed ELGs.

The T&E species expected to benefit from the rule include two species of sturgeon and five species of small minnows. All of these species have nonuse values including existence, bequest, altruistic, and ecological service values apart from human uses or motives.

To estimate the potential economic values of increased T&E species populations affected by the proposed ELGs, EPA used a benefit function transfer approach based on a meta-analysis of 31 stated preference studies eliciting WTP for these changes (Richardson and Loomis 2009). This meta-analysis is based on studies conducted in the United States that valued threatened, rare, or endangered fish, bird, reptile, or mammal species. Because the underlying meta-data does not include insect valuation studies, EPA was unable to monetize any benefits for potential population increases of Hine's Emerald Dragonfly due to the proposed rule. For each state containing T&E species estimated to show population growth because of the proposed ELGs, EPA calculated benefits using the weighted population growth assumptions under each analytic scenario (regulatory option and population increase assumption). For states with more than one T&E species estimated to see population growth, EPA only monetized the value for the species projected to see the greatest proportional population increase. Because population growth was calculated at the state level, EPA was unable to calculate benefits based on when each steam electric plant is assumed to install control technologies to comply with the proposed ELGs. EPA therefore assumed that benefits begin accruing in 2019 for all states because this is the midpoint of the compliance period used in other cost and benefit analyses and thus provides a reasonable assumption.

There may be some overlap between WTP estimates for T&E species and the WTP estimates for improvements in water quality; however, the magnitude of this overlap is likely to be minimal because none of the studies in EPA's meta-analysis of WTP for water quality improvements specifically mentioned or otherwise prompted respondents to include benefits to T&E species populations.

Table XIV–3 summarizes the results of EPA's analysis of benefits from improved ecological conditions and recreational uses for five of the eight regulatory options. EPA did not estimate the benefits of Options 3a, 3b and 4a. As for the other benefit categories, however, the Agency expects the benefits of Option 4a to be between those of Options 3 and 4 (i.e., between $59.9 million and $116.1 million annually, at 3 percent discount rate).

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TABLE XIV–3—ANNUALIZED ECOLOGICAL CONDITIONS AND RECREATIONAL USES BENEFITS

[Million 2010$] [e]

| Benefit category | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|---|---|---|---|---|---|
| **3% Discount Rate** | | | | | |
| Improved Surface Water Quality [a] | $8.3 ($2.0 to $22.4) | $38.0 ($7.1 to $107.1). | $49.9 ($10.2 to $137.6). | $82.8 ($19.6 to $215.8). | $81.9 ($19.3 to $214.1) |
| Benefits to E&T Species [b] | $7.0 ($3.9 to $10.0) | $7.0 ($3.9 to $10.0) | $10.0 ($5.5 to $14.2) | $33.3 ($18.2 to $47.3). | $33.3 ($18.2 to $47.3) |
| Total Ecological and Recreational Uses Benefits [d] | $15.3 ($5.8 to $32.4) | $45.0 ($11.0 to $117.7). | $59.9 ($15.7 to $151.8). | $116.1 ($37.8 to $263.1). | $115.2 ($37.5 to $261.4) |
| **7% Discount Rate** | | | | | |
| Improved Surface Water Quality [a] | $6.9 ($1.6 to $18.7) | $31.7 ($6.0 to $48.3) | $41.7 ($8.5 to $115.0). | $69.2 ($16.4 to $180.3). | $68.5 ($16.1 to $178.9) |
| Benefits to E&T Species [b] | $5.9 ($3.2 to $8.4) | $5.9 ($3.2 to $8.4) | $8.4 ($4.6 to $11.9) | $27.8 ($15.2 to $39.5). | $27.8 ($15.2 to $39.5) |
| Total Ecological and Recreational Uses Benefits [d] | $12.8 ($4.8 to $27.0) | $37.6 ($9.1 to $56.6) | $50.1 ($13.1 to $126.9). | $97.0 ($31.6 to $219.8). | $96.2 ($31.3 to $218.4) |

[a] Values represent partial benefits only for reaches that receive direct discharges from steam electric plants. Range in parenthesis represents the 5th and 95th percentile of the WTP distribution.
[b] Range in parenthesis provides the low and high bound estimates.
[c] Range in parenthesis provides the 5th and 95th percentile of the WTP distribution incorporating minimum and maximum flow reduction assumptions.
[d] Totals may not add up due to independent rounding.
[e] EPA did not estimate the benefits of Options 3a, 3b and 4a. EPA expects the benefits of Option 4a to be between those of Options 3 and 4.

3. Groundwater Quality Benefits From Reduced Groundwater Contamination

EPA expects that some of the regulatory options will eliminate the future leaching of steam electric pollutants from steam electric impoundments to groundwater aquifers. The Agency monetized the associated benefits to households using private drinking wells in the vicinity of steam electric plants based on a benefits transfer from groundwater valuation studies. Specifically, EPA used existing groundwater valuation studies to derive household WTP estimates for two categorical improvements in groundwater quality: (1) "greatly improved" and (2) "improved."

EPA identified the exposed population as the number of households using private drinking water wells in the vicinity of steam electric impoundments. EPA then modeled pollutant concentrations in the affected aquifers and determined which aquifers exceed maximum contaminant levels (MCLs) for steam electric pollutants under the baseline. EPA assumed that if a plant ceases to use impoundments to handle combustion waste because of the proposed ELGs, these aquifers would improve, with an average household WTP of $450. For impoundments that continue to receive combustion wastes but in smaller amounts, EPA assumed that the plant-specific benefits would be proportional to the reduction in wastewater flows going to the impoundment, and scaled the benefits accordingly.

Table XIV–4 summarizes the results of EPA's analysis of the groundwater benefits. As for other benefit categories, EPA did not analyze the benefits of Options 3a, 3b and 4a. EPA expects the benefits of Option 4a to be between those of Options 3 and 4 (i.e., $1.6 million to $6.5 million annually, at 3 percent discount rate).

TABLE XIV–4—ANNUALIZED GROUNDWATER QUALITY BENEFITS

[Million 2010$]

| Discount rate | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|---|---|---|---|---|---|
| 3% Discount Rate | $0.7 | $0.7 | $1.6 | $6.5 | $6.5 |
| 7% Discount Rate | 0.6 | 0.6 | 1.4 | 5.5 | 5.5 |

4. Market and Productivity Benefits (Benefits From Reduced Impoundment Failures)

Operational changes prompted by compliance with the proposed ELGs may cause some plant owners to reduce their reliance on impoundments to handle their waste. EPA expects these changes to reduce future impacts from impoundment failures.

To assess the benefits associated with changes in impoundment use, EPA estimated the costs associated with expected failures for baseline conditions (assuming no change in operations) and for projected reductions in the amount of CCR waste managed by impoundments for five of the eight regulatory options (Options 1, 2, 3, 4, and 5). EPA performed the calculations for each of the 1,070 impoundments identified at steam electric plants, and for each year between 2014 and 2040. EPA then calculated benefits as the difference between expected failure costs for a regulatory option and expected failure costs under baseline conditions.

To estimate the number of structural failure events that may be avoided as a result of the proposed ELGs, EPA used data on historical impoundment failures collected by EPA's Office of Resource Conservation and Recovery (ORCR) for its Regulatory Impact Analysis for EPA's Proposed Regulation of Coal Combustion Residues Generated by the Electric Utility Industry (Proposed CCR Rule; U.S. EPA 2010). Based on historical data, EPA estimated an average failure rate of 0.58 percent per impoundment per year and used this average failure rate to calculate the expected number of failure events in the baseline and under each of the regulatory options.[86] EPA also used data on historical failure events to develop average cleanup, natural resource damages,[87] and litigation costs[88] per event. As detailed in Chapter 7 of the BCA, EPA used average total costs of $0.06 per gallon of impoundment capacity to estimate the expected costs of an impoundment failure.[89] EPA did not calculate benefits for years 2014 through 2018 because EPA conducted surface impoundment integrity site assessments in 2009 through 2012 and expects the assessments and the recommended "action plan" improvements to impoundment structures will prevent all failures for the first five years after improvement are completed (i.e., 2014 through 2018).

Table XIV–5 presents the analysis results. Depending on the regulatory option, annual benefits range from $62.1 million to $295.1 million (at 3 percent discount rate), with Option 3 having expected benefits of $114.8 million per year. EPA did not estimate the benefits of Options 3a, 3b and 4a; the Agency expects the benefits of Option 4a to be between those of Options 3 and 4 (i.e., $114.8 million to $295.1 million, at 3 percent discount rate). Note that these benefits do not include the effects of BMPs that may reduce the probability of failures and therefore would be expected to increase the benefits of the proposed ELGs. EPA will continue to seek ways to quantify and monetize BMP-related benefits in analyses for the final rule, should EPA ultimately include such BMPs as part of the final ELGs.

TABLE XIV–5—ANNUALIZED BENEFITS OF REDUCED IMPOUNDMENT FAILURES

[Million 2010$]

| Discount rate | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|---|---|---|---|---|---|
| 3% Discount Rate | $62.1 | $62.1 | $114.8 | $295.1 | $295.1 |
| 7% Discount Rate | 52.2 | 52.2 | 95.9 | 245.9 | 245.9 |

5. Air-Related Benefits (Reduced Mortality and Avoided Climate Change Impacts)

The proposed ELGs are expected to affect air pollution through three main mechanisms: 1) additional auxiliary electricity use by steam electric plants to operate wastewater treatment, ash handling, and other systems needed to comply with the new effluent limitations and standards; 2) additional transportation-related emissions due to the increased trucking of CCR waste to landfills; and 3) the change in the profile of electricity generation due to the relatively higher cost to generate electricity at plants incurring compliance costs for the proposed ELGs. Changes in the profile of generation can result in lower or higher air pollutant emissions because of variability in emission factors for different types of electricity generating units. For this analysis, the changes in air emissions are based on the change in dispatch of generation units projected by IPM as a result of overlaying the costs of the proposed ELGs onto steam electric units production costs.

In this analysis, EPA estimated the human health and other benefits resulting from net changes in air emissions of three pollutants: nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), and carbon dioxide ($CO_2$). $NO_X$ and $SO_X$ are known precursors to fine particles ($PM_{2.5}$), a criteria air pollutant that has been associated with a variety of adverse health effects—most notably, premature mortality. $CO_2$ is an important greenhouse gas that is linked to a wide range of climate change effects.

EPA used average benefit-per-ton (BPT) estimates to value benefits of changes in $NO_X$ and $SO_2$ emissions, and social cost of carbon (SCC) estimates to value benefits of changes in $CO_2$ emissions. Because the analysis relies in part on estimates of air emissions obtained from IPM, EPA estimated air-related benefits for Options 3 and 4 only, as these are the two options analyzed in IPM. Table XIV–6

[86] EPA also estimated benefits using a best-fit regression equation developed based on the historical data that relates the probability of impoundment failure to impoundment capacity. For details, see Appendix G of the BCA.

[87] Natural resource damages do not include cleanup costs (or legal costs) but include only the resource restoration and compensation values. For example, in one case, Israel (2006) found that "In total, the State's claim was $764 million, $342 million of which was restoration cost damages, $410 million of which was compensable value damages, and $12 million of which was assessment and legal costs." For this case, EPA used the sum of $342 million and $410 million (excluded legal costs) as the value of natural resource damages.

[88] For this analysis, litigation costs include the costs associated with negotiating NRD, determining responsibility among potentially responsible parties, and litigating details regarding settlements and remediation. These activities involve services, whether performed by the complying entity or other parties that EPA expects would be required in the absence of this regulation in the event of an impoundment failure. Note that the litigation costs do not include fines, cleanup costs, damages, or other costs that constitute transfers or are already accounted for in the other categories analyzed separately.

[89] This estimate assumes that each failure results in a spilled volume equal to 6.45 percent of the impoundment capacity, based on the average ratio of spill volume to impoundment capacity for 15 releases for which ORCR obtained both spill volume and capacity data.

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summarizes the annualized benefits associated with changes in air pollutant emissions. Chapter 8 in the BCA report provides the details of this analysis.

TABLE XIV–6—ANNUALIZED BENEFITS OF CHANGES IN $NO_X$, $SO_2$, AND $CO_2$ AIR EMISSIONS

[Million 2010$] [c]

| Discount rate | Option 3 | Option 4 |
|---|---|---|
| 3% Discount Rate (for $NO_X$, $SO_2$, and $CO_2$-related benefits) | $127.6 | $170.5 |
| 7% Discount Rate (for $NO_X$, $SO_2$, and $CO_2$-related benefits) [a b] | 82.3 | 74.6 |

[a] Because SCC values are not available for the 7 percent discount rate, EPA used the SCC based on a 5 percent discount rate to estimate values presented for the 7 percent discount rate. EPA uses 5 percent to discount $CO_2$-related benefits and 7 percent to discount benefits from changes in $NO_X$ and $SO_2$ emissions.

[b] Air benefits for Option 4 at the 7 percent discount rate are lower than benefits estimated for Option 3 due to (1) smaller $SO_2$ emissions reductions projected by IPM for Option 4 than Option 3 in early years and (2) differences in source- and discount-specific BPT and SCC values.

[c] EPA did not estimate the benefits of Options 3a, 1, 2, 3b, 4a and 5. EPA expects the benefits of Option 4a to be between those of Options 3 and 4.

6. Benefits From Reduced Water Withdrawals (Increased Availability of Groundwater Resources)

Steam electric plants use water for handling solid waste (e.g., fly ash, bottom ash) and for operating wet FGD scrubbers. By eliminating or reducing water used in sluicing operations or prompting the recycling of water in FGD wastewater treatment systems, the proposed ELGs are expected to reduce water withdrawals from surface waterbodies and reduce demand on aquifers, in the case of plants that rely on groundwater sources.

EPA estimated the benefits of reduced groundwater withdrawals based on avoided costs of groundwater supply. For each affected facility and regulatory option, EPA multiplied the reduction in groundwater withdrawal (in gallons per year) by water costs ranging between $150 and $500 per acre-foot.

Table XIV–7 summarizes the annualized benefits associated with changes in water use by steam electric plants for five of the eight options. Chapter 9 in the BCA report provides the details of this analysis. While EPA did not estimate benefits of Options 3a, 3b and 4a, the Agency expects the benefits of Option 4a to be between those of Options 3 and 4.

TABLE XIV–7—ANNUALIZED MONETIZED BENEFITS OF REDUCED WATER WITHDRAWALS BY STEAM ELECTRIC PLANTS

[Million 2010$] [a]

| Benefit category | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|---|---|---|---|---|---|
| **3% Discount Rate** | | | | | |
| Avoided groundwater withdrawals | $0.0 | $0.0 | <$0.1 | $0.1 | $0.1 |
| **7% Discount Rate** | | | | | |
| Avoided groundwater withdrawals | 0.0 | 0.0 | <0.1 | 0.1 | 0.1 |

[a] EPA did not estimate the benefits of Options 3a and 4a. EPA expects the benefits of Option 4a to be between those of Options 3 and 4.

*C. Total Monetized Benefits*

Using the analysis approach described above, EPA estimates annual total benefits for the six monetized categories at approximately $82 million to $605.5 million (at 3 percent discount rate), depending on the option and based on EPA's analysis of five of the eight regulatory options (Table XIV–8). BAT and PSES option 3 has annual total benefits estimated at $311.7 million (at 3 percent discount rate). While EPA did not quantify the benefits of the other three preferred BAT and PSES Options (Option 3a, Option 3b and Option 4a), EPA expects the annual total benefits of Option 4a to be between those of Option 3 and 4 (i.e., $311.7 million to $605.5 million at 3 percent discount rate).

The monetized benefits of this proposed rule do not account for all benefits because, as described above, EPA is unable to monetize some categories. Examples of benefit categories not reflected in these estimates include non-cancer health benefits (other than IQ benefits from reduced childhood exposure to lead and in-utero exposure to mercury) and reduced cost of drinking water treatment for the pollutants with drinking water criteria. In addition, EPA's analysis of human health benefits associated with water quality improvements includes only partial benefits for directly receiving reaches.

EPA will continue to seek ways to monetize benefit categories not monetized in this proposal in order to provide a more accurate representation of benefits of the proposed rule.

TABLE XIV–8—SUMMARY OF TOTAL ANNUALIZED MONETIZED BENEFITS OF PROPOSED ELGS

[Million 2010$] [f]

| Benefit category | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|---|---|---|---|---|---|
| **3 Percent Discount Rate** | | | | | |
| Human Health Benefits [a c] | $3.9 | $4.0 | $7.7 | $17.2 | $17.2 |

TABLE XIV–8—SUMMARY OF TOTAL ANNUALIZED MONETIZED BENEFITS OF PROPOSED ELGS—Continued

[Million 2010$] [f]

| Benefit category | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|---|---|---|---|---|---|
| Improved Ecological Conditions and Recreational Uses [a b] | 15.3 | 45.0 | 59.9 | 116.1 | 115.2 |
| Groundwater Quality Benefits | 0.7 | 0.7 | 1.6 | 6.5 | 6.5 |
| Market and Productivity Benefits | 62.1 | 62.1 | 114.8 | 295.1 | 295.1 |
| Air-Related Benefits [d] | NE | NE | 127.6 | 170.5 | NE |
| Reduced Water Withdrawals | 0.0 | 0.0 | ≤0.1 | 0.1 | 0.1 |
| Total benefits, Excluding Air-Related Benefits | 82.0 | 111.7 | 184.1 | 435.0 | 434.1 |
| Total Benefits (Including Air-related Benefits) [a] | ..... | ..... | 311.7 | 605.5 | ..... |
| **7 Percent Discount Rate** | | | | | |
| Human Health Benefits [a c] | 0.4 | 0.4 | 0.7 | 1.6 | 1.6 |
| Improved Ecological Conditions and Recreational Uses [a b] | 12.8 | 37.6 | 50.1 | 97.0 | 96.2 |
| Groundwater Quality Benefits | 0.6 | 0.6 | 1.4 | 5.5 | 5.5 |
| Market and Productivity Benefits | 52.2 | 52.2 | 95.9 | 245.9 | 245.9 |
| Air-Related Benefits [d e] | NE | NE | 82.3 | 74.5 | NE |
| Reduced Water Withdrawals | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 |
| Total benefits, Excluding Air-Related Benefits | 65.9 | 90.7 | 148.1 | 350.2 | 349.4 |
| Total Benefits (Including Air-related Benefits) [a] | ..... | ..... | 230.4 | 424.8 | ..... |

[a] Values represent mean benefit estimates. Totals may not add up due to independent rounding. Option 5 results in slightly lower benefits because, under Option 4, EPA assumes that plants with both leachate and FGD waste streams implement chemical precipitation and biological treatment for the combined streams. Under Option 5, EPA assumes that plants treat the two streams separately: FGD wastewater by evaporation and leachate using chemical precipitation (which removes less pollutant load than biological treatment).

[b] There may be some overlap between the willingness-to-pay (WTP) for surface water quality improvements and WTP for benefits to threatened and endangered species.

[c] Values represent partial human health benefits only for reaches that receive direct discharges from steam electric plants.

[d] EPA estimated air-related benefits for Options 3 and 4 only because these benefits were estimated as part of the Agency's analysis using IPM. Total benefits for Options 1, 2, and 5 are therefore understated. Air benefits for Option 4 at the 7 percent discount rate are lower than benefits estimated for Option 3 due to (1) smaller $SO_2$ emissions reductions projected by IPM for Option 4 than Option 3 in early years and (2) differences in source- and discount-specific BPT and SCC values.

[e] Because SCC values are not available for the 7 percent discount rate, EPA used the SCC based on a 5 percent discount rate and discounted $CO_2$-related benefits using a 5 percent discount rate, as compared to benefits in other categories, which are discounted using the 7 percent discount rate.

[f] EPA did not estimate benefits for Options 3a, 3b and 4a, but expects the benefits of Option 4a to be between those of Options 3 and 4.

Further, as noted earlier in this section, EPA calculated benefits for some of the options considered for this proposal. Benefits for these options, however, provide information relevant to understanding the potential magnitude of benefits under all proposed options, including Options 3a, 3b, and 4a. As explained earlier in this preamble, the facilities affected by Option 3a are a subset of Option 3 facilities; Option 3 benefit estimates therefore provide an upper bound estimate of benefits anticipated under Options 3a and 3b. In a similar way, EPA expects Option 4 to provide an upper bound estimate of benefits anticipated under Option 4a. As an illustrative analysis, EPA inferred the potential benefits associated with Options 3a and 3b by subtracting the benefits for Option 2 (scaled up to include a rough estimate of air emissions benefits) from the benefits for Option 3, because Option 3 includes a combination of the wastestreams and control technologies in Options 3a and 2. EPA inferred the potential benefits associated with Option 3b based on the pollutant loading reductions (pounds) projected for Option 3b relative to pollutant loading reductions projected for Option 2 (plus the fly ash dry handling benefits of Option 3a) because Option 3b includes both fly ash requirements and the Option 2 FGD wastewater treatment requirements for a subset of facilities. Specifically, EPA inferred the benefits of Options 3a and 3b by multiplying the FGD benefits estimated for Option 2 by the ratio of pollutant loads removed by 3b over Option 2, and then adding in the fly ash benefits that are also included in Option 3b. Similarly, EPA inferred the potential benefits associated with Option 4a based on the bottom ash pollutant loading reductions projected for this option, relative to bottom ash pollutant loading reductions projected for Option 4, plus the benefits of Option 3, because Option 4a includes all of the requirements of option 3 plus the bottom ash requirements of Option 4 for a subset of facilities.

Table XIV–9 summarizes total annualized benefits estimated (or inferred using the calculations described above) for the eight options discussed in this proposal. Note that there is significant uncertainty in values inferred because the methodology used does not account for differences in the pollutants, receiving waterbodies, and exposed populations between the options.

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TABLE XIV–9—TOTAL MONETIZED BENEFITS FOR THE PROPOSED RULE

[Millions; 2010]

| Regulatory option | Method | Total monetized benefits 3% | Total monetized benefits 7% |
|---|---|---|---|
| Option 1 | Estimate [a] | $82.0 | $65.9 |
| Option 3a | Inference [b] | 139.4 | 104.8 |
| Option 2 | Estimate [a] | 111.7 | 90.7 |
| Option 3b | Inference [b] | 205.5 | 153.0 |
| Option 3 | Estimate | 311.7 | 230.4 |
| Option 4a | Inference [b] | 482.5 | 343.4 |
| Option 4 | Estimate | 605.5 | 424.8 |
| Option 5 | Estimate [a] | 434.1 | 349.4 |

[a] Total benefits for Options 1, 2, and 5 do not include air-related benefits (see Table XIV–8).
[b] EPA did not estimate benefits for Options 3a, 3b and 4a. EPA inferred benefits for Options 3a, 3b, and 4a for illustrative purposes using elements of the more rigorous analysis done to estimate benefits for Options 3 and 4.

*D. Children's Environmental Health*

As described in Section XIV.B.1, EPA assessed whether these proposed ELGs will benefit children by reducing health risk from exposure to steam electric pollutants from consumption of contaminated fish tissue and improving recreational opportunities. The Agency was able to quantify two categories of benefits specific to children: (1) Avoided neurological damage to pre-school age children from reduced exposure to lead and (2) avoided neurological damages from in-utero exposure to mercury.

This analysis considered several measures of children's health benefits associated with lead exposure for children up to age six. Avoided neurological and cognitive damages were expressed as changes in three metrics: (1) Overall IQ levels; (2) the incidence of low IQ scores (<70); and (3) the incidence of blood-lead levels above 20 mg/dL. EPA's methodology for assessing lead-related benefits to children is presented in Chapter 3 of the BCA report. EPA analysis shows that benefits to children from reduced lead discharges range from $0.1 million to $6.8 million (at 3 percent discount), depending on the regulatory option; annual benefits for Option 3 are estimated at $2.7 million (at 3 percent discount rate). EPA did not quantify the benefits to children of Options 3a, 3b and 4a; however, the Agency expects the annual benefits of Option 4a to be between those of Options 3 and 4 (i.e., between $2.7 million and $6.8 million).

Children over the age of seven are also likely to benefit from reduced exposure to lead and the resultant neurological and cognitive damages, even though EPA did not quantify these benefits in its analysis of the proposed ELGs. Giedd et al. (1999) studied brain development among 10- to 18-year-old children and found substantial growth in brain development, mainly during early teenage years. This research suggests that older children may be hypersensitive to lead exposure, as are children aged 0 to 7.

Additional benefits to children from reduced exposure to lead not quantified in this analysis may include prevention of the following adverse health effects: slowed or delayed growth, delinquent and anti-social behavior, metabolic effects, impaired heme synthesis, anemia, impaired hearing, and cancer.

EPA also estimated the IQ-related benefits associated with reduced in-utero mercury exposure from maternal fish consumption in exposed populations. Chapter 3 of the BCA report presents EPA's methodology for assessing mercury-related benefits to children. Among approximately 1,932 babies born per year who are potentially exposed to discharges of mercury from steam electric plants, the proposed ELGs reduce total IQ point losses over the period of 2017 through 2040 by about 9,000 to 24,000 points, depending on the regulatory option. The monetary benefits associated with the avoided IQ point losses range from $3.8 million and $10.2 million per year (mean estimate, at 3 percent discount rate), across the five options EPA analyzed. Option 3 is estimated to avoid the loss of about 12,000 IQ points in exposed infants over the 24-year period. The benefits associated with these avoided IQ point losses are estimated at $5.0 million per year. EPA did not quantify the benefits to children of Options 3a, 3b and 4a; for Option 4a, however, EPA expects the annual benefits to be between those of Options 3 and 4 (i.e., $5.0 million to $10.2 million).

## XV. Non-Water Quality Environmental Impacts

The elimination or reduction of one form of pollution may create or aggravate other environmental problems. Therefore, Sections 304(b) and 306 of the Act require EPA to consider non-water quality environmental impacts (including energy impacts) associated with ELGs. Accordingly, EPA has considered the potential impact of the regulatory options on air emissions, solid waste generation, and energy consumption.

*A. Energy Requirements*

Steam electric power plants use energy when transporting ash and other solids on or off site, operating wastewater treatment systems (e.g., chemical precipitation, biological treatment), operating ash handling systems, or operating water trucks for dust suppression. For those facilities that it projected would incur costs to comply with these regulatory options, EPA considered whether or not there would be an associated incremental energy need. That need varies depending on the regulatory option evaluated and the current operations of the facility. Therefore, as applicable, EPA estimated the additional energy usage in megawatt hours (MWh) for equipment added to the plant systems or in consumed fuel (gallons) for transportation/operating equipment. Similarly, as applicable, EPA also estimated the decrease in energy requirements resulting from the reduction in wet sluicing operations and use of earth moving equipment. EPA scaled the facility-specific estimate to calculate the net increase in energy requirements for the regulatory options discussed in this rulemaking.

To determine potential increases in electrical energy use, EPA estimated the amount of energy needed to operate wastewater treatment systems and ash handling systems based on the horsepower rating of the pumps and other equipment. To determine potential decreases in electrical energy use, EPA estimated the amount of

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energy saved from reducing wet sluice pumping operations based on the horsepower rating of the pumps. See DCN SE01957 (*Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category*) for more information on the specific calculations used to estimate changes in energy use. Table XV–1 shows the net change in annual electrical energy usage associated with the proposed regulation.

Energy usage also includes the fuel consumption associated with transportation. EPA estimated the need for increased transportation of solid waste and combustion residuals (e.g., ash) at steam electric power plants to on-site or off-site landfills using open dump trucks. The frequency and distance of transport depends on a plant's operation and configuration. For example, the volume of waste generated per day determines the frequency with which trucks will be travelling to and from the storage sites. The availability of either an on-site or off-site non-hazardous landfill and its distance from the plant determines the length of travel time. EPA also estimated the energy usage associated with the dust suppression water trucks and earth moving equipment based on specific plant operations. For example, EPA calculated earth moving equipment energy usage only if the plant operates an impoundment. To determine the potential decrease in fuel consumption, EPA estimated the amount of fuel saved by reducing the number of backhoes needed to dredge solids from ash impoundments, due to the reduction of wet sluice operations. See DCN SE01957 (*Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category*) for more information on the specific calculations used to estimate transportation fuel usage. Table XV–1 shows the net change in annual fuel consumption associated with the preferred BAT and PSES regulatory options (Options 3a, 3b, 3, and 4a).

To provide some perspective on the potential increase in annual electric energy consumption associated with the preferred regulatory options, EPA compared the estimated increase in energy usage (MWh) to the net amount of electricity generated in a year by all electric power plants throughout the United States. According to EPA's Emissions & Generation Resource Integrated Database (eGRID), the power plant industry generated approximately 3,951 million MWh of energy in 2009. EPA estimates that energy increases associated with the preferred BAT and PSES regulatory options range from less than 0.003 percent (Option 3a) to 0.012 percent (Option 4a) of the total electricity generated by all electric power plants.

Similarly, EPA compared the additional fuel consumption (gallons) estimated for the preferred BAT and PSES regulatory options to national fuel consumption estimates for motor vehicles in the United States. According to the EIA, on-highway vehicles, which include automobiles, trucks, and buses, consumed approximately 34 billion gallons of distillate fuel oil in 2009. EPA estimates that the fuel consumption increase associated with the proposed Option 3a for BAT and PSES will be 0.008 percent of total fuel consumption by all motor vehicles. Fuel consumption is estimated to increase by less than 0.009 percent under Options 3b and Option 3, and less than 0.014 percent under Option 4a.

TABLE XV–1—ENERGY USE ASSOCIATED WITH ELG OPTIONS 3a, 3b, 3, AND 4a

| Non-water quality impact | Energy use associated with proposed rule | | | |
|---|---|---|---|---|
| | Option 3a | Option 3b | Option 3 | Option 4a |
| Electrical Energy Usage (MWh) | 112,000 | 160,753 | 303,300 | 472,369 |
| Fuel (Thousand Gallons) | 2,867 | 2,903 | 3,040 | 4,618 |

*B. Air Pollution*

The proposed ELGs are expected to affect air pollution through three main mechanisms: (1) Additional auxiliary electricity use by steam electric plants to operate wastewater treatment, ash handling, and other systems needed to comply with the new effluent limitations and standards; (2) additional transportation-related emissions due to the increased trucking of CCR waste to landfills; and (3) the change in the profile of electricity generation due to relatively higher cost to generate electricity at plants incurring compliance costs for the proposed ELGs. This section provides greater detail on air emission changes associated with the first two mechanisms and presents the estimated net change in air emissions that take all three mechanisms into account. See Section XIV for additional discussion of the third mechanism.

Air pollution is generated when fossil fuels are combusted. In addition, steam electric power plants generate air emissions from operating transport vehicles, such as dump and vacuum trucks, dust suppression water trucks, and earth-moving equipment, which release criteria air pollutants and greenhouse gases when operated. Similarly, a decrease in energy use or vehicle operation will result in decreased air pollution.

To estimate the net air emissions associated with increased electrical energy use, EPA combined the energy usage estimates with air emission factors associated with electricity production to calculate air emissions associated with the incremental energy requirements for each of the proposed regulatory options. EPA used emission factors projected by IPM (ton/MWh) for nitrogen oxides, sulfur dioxide, and carbon dioxide to generate estimates of increased air emissions associated with increased energy production.

To estimate net air emissions associated with increased operation of transport vehicles, EPA used the MOBILE6.2 model and the California Climate Action Registry, General Reporting Protocol, Version 2.2 to identify air emission factors (gram per mile) for the air pollutants of interest. EPA assumed the general input parameters such as the year of the vehicle and the annual mileage accumulation by vehicle class to develop these factors. EPA estimated the annual number of miles that dump or vacuum trucks moving ash or wastewater treatment solids to on- or offsite landfills would travel to comply with limits established by the proposed regulatory options. In addition to the trucks transporting the additional solid waste, EPA also estimated the annual number of miles that water trucks spraying water around landfills and ash unloading areas to control dust would travel. EPA used these estimates to calculate the net change in air emissions for this rulemaking.

EPA's analyses using IPM also predict changes in air emissions. The modeled

output from IPM predicts changes in electricity generation due to compliance costs attributable to the proposed regulatory options. These changes in electricity generation are, in turn, predicted to affect the air emissions from steam electric power plants.

The net change in air emissions associated with the preferred BAT/PSES regulatory options (Options 3a, 3b, 3, and 4a) are shown in Tables XV–2 through XV–5. To provide some perspective on the potential changes in annual air emissions, EPA compared the estimated change in air emissions to the net amount of air emissions generated in a year by all electric power plants throughout the United States. Tables XV–2 through XV–4 present the estimated changes in air emissions based on the regulatory options, the total emissions generated by the electric power industry in 2009, based on eGRID, and the percent change in emissions associated with Options 3a, 3b, 3, and 4a. See DCN SE02025 (*Steam Electric Effluent Guidelines Non-Water Quality Impacts*) in the record for this rulemaking for more information.

TABLE XV–2—AIR EMISSIONS ASSOCIATED WITH BAT/PSES OPTION 3a

| Non-water quality impact | Value associated with option 3a (million tons) | 2009 Emissions by electric power industry (million tons) | Increase in emissions (%) |
|---|---|---|---|
| $NO_X$ | [a] 0.000088–0.00109 | 1 | 0.0088–0.109 |
| $SO_X$ | [b] <0.000084 | 6 | <0.0014 |
| $CO_2$ | [b] <0.130 | 2,403 | <0.0054 |

[a] EPA quantified the air emissions associated with additional electricity and additional transportation for Option 3a. Based on the values quantified for Option 3 for changes to air emissions projected by IPM, EPA calculated the range of emissions for $NO_X$. The lower end of the range represents the emissions only associated with additional electricity and transportation. The upper end of the range also includes the changes to air emissions projected by IPM (based on Option 3), which are larger than would be expected for Option 3a.

[b] EPA quantified the air emissions associated with additional electricity and additional transportation for Option 3a. Based on the values quantified for Option 3 for changes to air emissions projected by IPM, which were negative, EPA decided not to include these IPM air emission changes in the calculated SOx and $CO_2$ emissions for Option 3a. These $SO_X$ and $CO_2$ emissions are considered maximum values because EPA expects that the air emission changes projected by IPM for Option 3a will also be negative (as they are for Options 3 and 4).

TABLE XV–3—AIR EMISSIONS ASSOCIATED WITH BAT/PSES OPTION 3b

| Non-water quality impact | Value associated with option 3b (million tons) | 2009 Emissions by electric power industry (million tons) | Increase in emissions (%) |
|---|---|---|---|
| $NO_X$ | [a] 0.00011–0.00111 | 1 | 0.011–0.111 |
| $SO_X$ | [b] <0.00013 | 6 | <0.0021 |
| $CO_2$ | [b] <0.149 | 2,403 | <0.0062 |

[a] EPA quantified the air emissions associated with additional electricity and additional transportation for Option 3b. Based on the values quantified for Option 3 for changes to air emissions projected by IPM, EPA calculated the range of emissions for $NO_X$. The lower end of the range represents the emissions only associated with additional electricity and transportation. The upper end of the range also includes the changes to air emissions projected by IPM (based on Option 3), which are larger than would be expected for Option 3b.

[b] EPA quantified the air emissions associated with additional electricity and additional transportation for Option 3b. Based on the values quantified for Option 3 for changes to air emissions projected IPM, which were negative, EPA decided not to include these IPM air emission changes in the calculated $SO_X$ and $CO_2$ emissions for Option 3b. These $SO_X$ and $CO_2$ emissions are considered maximum values because EPA expects that the air emission changes projected for IPM for Option 3b will also be negative (as they are for Options 3 and 4).

TABLE XV–4—AIR EMISSIONS ASSOCIATED WITH BAT/PSES OPTION 3

| Non-water quality impact | Value associated with option 3 (million tons) | 2009 Emissions by electric power industry (million tons) | Increase in emissions (%) |
|---|---|---|---|
| $NO_X$ | 0.00121 | 1 | 0.121 |
| $SO_X$ | −0.00273 | 6 | −0.045 |
| $CO_2$ | −1.282 | 2,403 | −0.053 |

TABLE XV–5—AIR EMISSIONS ASSOCIATED WITH BAT/PSES OPTION 4a

| Non-water quality impact | Value associated with option 4a (million tons) | 2009 Emissions by electric power industry (million tons) | Increase in emissions (%) |
|---|---|---|---|
| $NO_X$ | [a] 0.00132 | 1 | 0.132 |
| $SO_X$ | [a] < −0.00258 | 6 | < −0.043 |
| $CO_2$ | [a] < −1.106 | 2,403 | < −0.046 |

[a] EPA quantified the air emissions associated with additional electricity and additional transportation for Option 4a. To estimate the total emissions for Option 4a, EPA added the changes to air emissions projected by IPM for Options 3 because they are more conservative (i.e., they overestimate the emissions). The contribution of $NO_X$ is unchanged compared to Option 3 and 4; therefore, EPA assumed this would also be the contribution for Option 4a. For $SO_X$ and $CO_2$, the contribution associated with Option 4 are lower (i.e., more negative); therefore, because EPA used the Option 3 values, the values presented in the table are maximum values.

*C. Solid Waste Generation*

Steam electric power plants generate solid waste associated with sludge from wastewater treatment systems (e.g., chemical precipitation, biological treatment). The regulatory options evaluated would increase the amount of solid waste generated from FGD wastewater treatment, including sludge from chemical precipitation, biological treatment, and vapor compression evaporation technologies. EPA estimated the amount of solid waste generated from each technology for each plant and estimates that the preferred BAT/PSES regulatory options (Options 3a, 3b, 3, and 4a) would increase solids generated annually from treatment. Fly and bottom ash are also solid wastes generated at steam electric power plants. The preferred regulatory options for BAT and PSES are, however, not expected to alter the amount of ash or other combustion residuals generated. See DCN SE02025 (*Steam Electric Effluent Guidelines Non-Water Quality Impacts*) in the record for this rulemaking for more information.

To provide some perspective on the potential increase in annual solid waste generation associated with the preferred BAT/PSES regulatory options, EPA compared the estimated increase in solid waste generation for Options 3b, 3, and 4a [90] to the amount of solids generated in a year by electric power plants throughout the United States—approximately 134 billion tons. The increase in solid waste generation associated with Options 3b, 3 and 4a for BAT and PSES will be less than 0.001 percent of the total solid waste generated by all electric power plants.

*D. Reductions in Water Use*

Steam electric power plants generally use water for handling solid waste, including ash, and for operating wet FGD scrubbers. The technology options for fly and bottom ash will eliminate or reduce water use associated with current wet sluicing operating systems. EPA estimated the reductions in water use based on the amount of sluice water discharged by each plant, multiplied by the percentage of intake water identified as make-up in the survey. The memorandum entitled *Steam Electric Effluent Guidelines Non-Water Quality Impacts,* located in the record for this rulemaking, provides more information.

The technology basis for the preferred regulatory option with respect to FGD wastewater discharges (e.g., chemical precipitation, biological treatment) would not be expected to reduce the amount of water used unless plants recycle FGD wastewater as part of their treatment system. EPA estimated that five plants would be able to incorporate recycling within their FGD systems based on the maximum operating chlorides concentration compared to the design maximum chlorides concentration. Based on this comparison, EPA estimated the reduction in intake water at a plant level based on the amount of water that could be recycled by the FGD system and multiplying by the percentage of intake water identified as make-up water in the industry survey. EPA's report entitled *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category,* located in the record for this rulemaking, provides more information.

EPA estimates that power plants would reduce the use of water by 50 billion gallons per year (136 million gallons per day) under Option 3a, by 52 billion gallons per year (143 million gallons per day) under Option 3b, by 53 billion gallons per year (144 million gallons per day) under Option 3, and by 103 billion gallons per year (282 million gallons per day) under Option 4a.

## XVI. Regulatory Implementation

*A. Implementation of the Limitations and Standards*

Effluent guidelines limitations and standards act as a primary mechanism to control the discharge of pollutants to waters of the United States. This proposed rule would be applied to steam electric wastewater discharges through incorporation into NPDES permits issued by the EPA or states under Section 402 of the Act and through local pretreatment programs under Section 307 of the Act.

The Agency has developed the limitations and standards for this proposed rule to control the discharge of pollutants from the steam electric power generating point source category. Once promulgated, those permits or control mechanisms issued after this rule's effective date would be required to incorporate the effluent limitations guidelines and standards, as applicable. Also, under section 510 of the CWA, states may require effluent limitations under state law as long as they are no less stringent than the requirements of this rule. Finally, in addition to requiring application of the technology-based effluent limitations guidelines and standards in this rule, section 301(b)(1)(C) of CWA requires the permitting authority to impose more stringent effluent limitations on discharges as necessary to meet applicable water quality standards.

1. Timing

For the reasons explained in Section VIII, EPA proposes that certain limitations and standards based on any of the eight main regulatory options being proposed today for existing direct and indirect dischargers do not apply until July 1, 2017 (approximately three years from the effective date of this rule). EPA finds this is appropriate for any proposed BAT and PSES for FGD wastewater, gasification wastewater, fly ash transport water, flue gas mercury control wastewater, bottom ash transport water, or combustion residual leachate where EPA is not proposing to establish BAT limitations that are equal to BPT limitations. For those plants and wastestreams where EPA is proposing to establish BAT equal to the current BPT effluent limitations, the revised BAT requirements would be applicable on the effective date of the final rule. See Section VIII.B for additional discussion regarding the implementation timing for the proposed BAT and PSES requirements.

The proposed requirements for new direct and indirect dischargers (NSPS and PSNS) and the proposed requirements for existing sources where BAT is set equal to BPT would be applicable as of the effective date of the final rule.

2. Applicability of NSPS/PSNS

In 1982, EPA promulgated NSPS/PSNS for certain discharges from new units. Regardless of the outcome of the current rulemaking, those units that are currently subject to the 1982 NSPS/PSNS will continue to be subject to such standards. In addition, EPA is proposing to clarify in the text of the regulation that, assuming the Agency promulgates BAT/PSES requirements as part of the current rulemaking, units to which the 1982 NSPS/PSNS apply will also be subject to any newly promulgated BAT/PSES requirements because they will be existing sources with respect to such new requirements.

3. Legacy Wastes

For the reasons explained in Section VIII, EPA is proposing that certain BAT and PSES requirements for existing sources based on any of the eight main regulatory options would apply to discharges of FGD wastewater, fly ash

[90] As described previously, the preferred regulatory options for BAT and PSES for fly ash and bottom ash transport water are not expected to alter the amount of ash or other combustion residuals generated. Therefore, there is no increase for Option 3a and the increase for Option 4a is equal to the increase for Option 3.

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transport water, bottom ash transport water, FGMC wastewater, combustion residual leachate, and gasification wastewater generated on or after the date established by the permitting authority that is as soon as possible after July 1, 2017.[91] As proposed today, for direct dischargers such wastewater generated prior to that date (i.e., "legacy" wastewater) would remain subject to the existing BPT effluent limits. EPA is also considering establishing BAT effluent limitations for legacy wastewater (except gasification wastewater) that would be equal to the existing BPT effluent limits.

4. Compliance Monitoring

Working in conjunction with the effluent limitations guidelines and standards are the monitoring conditions set out in a NPDES discharge permit or POTW control mechanism. An integral part of the monitoring conditions is the monitoring point. The point at which a sample is collected can have a dramatic effect on the monitoring results for that facility. Therefore, it may be necessary to require internal monitoring points in order to assure compliance. Authority to address internal wastestreams is provided in 40 CFR 122.44(i)(1)(iii) and 122.45(h).

EPA is proposing that dischargers demonstrate compliance with the proposed effluent limitations and standards applicable to a particular wastestream prior to mixing the treated wastestream with other wastestreams, as described below. Therefore, with the exception of the cases where BAT limitations are equivalent to BPT limitations, any final limitations or standards (except pH) based on any of the eight main regulatory options in this proposed rule could require internal monitoring points. Section 14 of the TDD provides detailed discussion for various types of configurations. The following provides selected information from the TDD:

- FGD wastewater: Where an option proposes BAT/NSPS limitations for FGD wastewater that are not equal to existing BPT limitations,[92] EPA is also proposing to require monitoring for compliance with the proposed effluent limitations and standards prior to use of the FGD wastewater in any other non-FGD plant process or commingling of the FGD wastewater with any water or other process wastewater. This monitoring requirement would not, however, apply prior to commingling of FGD wastewater with combustion residual leachate (including legacy leachate) or legacy FGD wastewater that is treated to achieve pollutant removals equivalent to or greater than achieved by the BAT/NSPS technology that serves as the basis for the effluent limitations and standards proposed today.

For example, many plants currently treat their FGD wastewater and leachate in onsite surface impoundments. EPA envisions that, under this proposed Option 3 requirements, some of these plants may choose to install tank-based FGD wastewater treatment systems for their newly generated FGD wastewater. Such a plant may chose to discharge the effluent from its new treatment system directly or may wish to discharge it to the existing surface impoundment containing legacy wastewaters. In this case, the plant would be required to demonstrate compliance with the proposed effluent limitations and standards for the newly generated FGD wastewater at the effluent from the tank-based FGD wastewater treatment system, and compliance with the BPT requirements for the commingled new/legacy FGD wastewater at the point of discharge from the FGD wastewater impoundment. The same plant may also configure its system so that the impoundment (which also contains legacy FGD wastewater)is used for equalization, with the impoundment effluent sent to the tank-based treatment system. In this case, both the newly generated FGD wastewater and the legacy FGD wastewater would be treated by the tank-based treatment system and an appropriate compliance monitoring point would be the treatment system effluent. Under such a scenario, commingling of FGD wastewater generated at any date may occur as long as such combined wastewater meets the effluent limitations or standards prior to use of the treated commingled new/legacy FGD wastewater in any other plant process, or combining the FGD wastewater with any water or other process wastewater.

- Ash transport water and FGMC wastewater: EPA is proposing to specify that whenever ash transport water or flue gas mercury control wastewater generated from a generating unit that must comply with the "zero discharge" standard is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the proposed discharge prohibition for the pollutants in such wastewater.

For example, many plants currently treat their fly ash transport water in an onsite fly ash impoundment. In this case, under any proposed "no discharge" requirements, EPA envisions that such plants may convert their fly ash handling to a dry system, and no longer generate fly ash transport water. In such cases, the plant could demonstrate compliance with the proposed zero discharge requirement by showing that no fly ash transport water is generated after the date on which the new, proposed standards apply and by monitoring for compliance with the BPT requirements at the discharge from the legacy fly ash impoundment. Under EPA's proposal, the plant could not demonstrate compliance with the applicable discharge prohibition by simply using the fly ash transport water in another plant process that ultimately discharges because the prohibition on the discharge of pollutants in ash transport water and FGMC wastewater is also applicable to the discharge of wastewater from plant processes that use these wastewaters.

- Gasification wastewater: EPA is proposing to require monitoring for compliance prior to use of the gasification wastewater in any other plant process or commingling of the gasification wastewater with water or any other process wastewater. As an example, EPA envisions gasification plants would show compliance with the proposed BAT or PSES requirements directly following gasification wastewater treatment (however, there would be no need to demonstrate compliance if the gasification wastewater is completely reused within the gasification process). Combustion Residual Leachate: Under Option 4 and 5, EPA is proposing to require monitoring for compliance prior to use of leachate in any other plant process or commingling of the leachate with water or any other process wastewater. This monitoring requirement would not, however, apply prior to commingling of combustion residual leachate with FGD wastewater (including legacy FGD wastewater) or legacy combustion residual leachate that is treated to achieve pollutant removals equivalent to or greater than that achieved by the BAT/NSPS technology that serves as the basis for the effluent limitations and standards proposed today. For example, many plants currently treat their leachate in onsite surface impoundments. EPA envisions that, under the proposed requirements, some plants may choose to install a tank-based leachate treatment system so that the impoundment (which also contains legacy combustion residual leachate) is used for equalization, with the impoundment effluent ultimately sent to the tank-based treatment system. In this case, both the newly generated leachate and the legacy leachate would

[91] Except where BAT is equivalent to BPT.

[92] Similarly applies to PSES and PSNS.

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be treated by the tank-based treatment system and an appropriate compliance monitoring point would be the treatment system effluent. Under such a scenario, commingling of combustion residual leachate generated at any date may occur as long as such combined wastewater meets the effluent limitations or standards prior to use of the treated commingled new/legacy leachate in any other plant process, or combining the leachate with any water or other process wastewater. (If the combustion residual leachate is commingled with FGD wastewater, the facility will also have to demonstrate compliance with the applicable FGD wastewater effluent limitations and standards.) Conversely, under the proposed requirements, EPA envisions some plants may choose to install tank-based leachate treatment systems whose effluent is discharged to the impoundment containing the legacy leachate. In this case, the plant would be required to demonstrate compliance with the proposed effluent limitations and standards for the newly generated combustion residual leachate at the effluent from the tank-based leachate treatment system and compliance with the BPT requirements for the commingled new/legacy leachate at the discharge from the impoundment.

*B. Analytical Methods*

Section 304(h) of the CWA directs the EPA to promulgate guidelines establishing test procedures (methods) for the analysis of pollutants. These methods are used to determine the presence and concentration of pollutants in wastewater and for compliance monitoring. They are also used for filing applications for the National Pollutant Discharge Elimination System (NPDES) permit program under 40 CFR 122.41(j)(4) and 122.21(g)(7), and under 40 CFR 403.7(d) for the pretreatment program. The EPA has promulgated analytical methods for monitoring discharges to surface water at 40 CFR part 136 for the pollutants proposed for regulation in this notice. EPA is providing notice of standard operating procedures (SOPs) for the analysis of FGD wastewater using collision cell technology in conjunction with EPA Method 200.8. EPA Method 200.8 has been promulgated under 40 CFR part 136 and is an approved method for use in NPDES compliance monitoring. Also, the use of collision cell technology is an approved modification allowed under 40 CFR part 136.6. See DCN SE03835 and DCN SE03868 for the SOPs and information on EPA's development of the SOPs.

In addition, as explained in Section VIII, with the exception of the cases where BAT limitations are equivalent to BPT limitations, EPA is proposing that compliance with any final limitations or standards (except pH) based on any of the eight main regulatory options in this proposed rule reflects results obtained from sufficiently sensitive analytical methods. Where EPA has approved more than one analytical method for a pollutant, the Agency expects that permittees would select methods that are able to quantify the presence of pollutants in a given discharge at concentrations that are low enough to determine compliance with effluent limits. For purposes of the proposed anti-circumvention provisions, a method is "sufficiently sensitive" when the sample-specific quantitation level [93] for the wastewater matrix being analyzed is at or below the level of the effluent limit.

*C. Upset and Bypass Provisions*

A "bypass" is an intentional diversion of wastestreams from any portion of a treatment facility. An "upset" is an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. EPA's regulations concerning bypasses and upsets for direct dischargers are set forth at 40 CFR 122.41(m) and (n) and for indirect dischargers at 40 CFR 403.16 and 403.17.

*D. Variances and Modifications*

The CWA requires application of effluent limitations established pursuant to Section 301 or the pretreatment standards of Section 307 to all direct and indirect dischargers. However, the statute provides for the modification of these national requirements in a limited number of circumstances. The Agency has established administrative mechanisms to provide an opportunity for relief from the application of the national effluent limitations guidelines for categories of existing sources for toxic, conventional, and nonconventional pollutants.

*1. Fundamentally Different Factors (FDF) Variance*

As explained above, the CWA requires application of the effluent limitations established pursuant to Section 301 or the pretreatment standards of Section 307 to all direct and indirect dischargers. However, the statute provides for the modification of these national requirements in a limited number of circumstances. Moreover, the Agency has established administrative mechanisms to provide an opportunity for relief from the application of national effluent limitations guidelines and pretreatment standards for categories of existing sources for priority, conventional, and nonconventional pollutants.

EPA may develop, with the concurrence of the state, effluent limitations or standards different from the otherwise applicable requirements for an individual existing discharger if it is fundamentally different with respect to factors considered in establishing the effluent limitations or standards applicable to the individual discharger. Such a modification is known as an FDF variance.

EPA, in its initial implementation of the effluent guidelines program, provided for the FDF modifications in regulations, which were variances from the BPT effluent limitations, BAT limitations for toxic and nonconventional pollutants, and BCT limitations for conventional pollutants for direct dischargers. FDF variances for toxic pollutants were challenged judicially and ultimately sustained by the Supreme Court in *Chemical Manufacturers Association* v. *Natural Resources Defense Council,* 470 U.S. 116, 124 (1985).

Subsequently, in the Water Quality Act of 1987, Congress added a new section to the CWA—Section 301(n). This provision explicitly authorizes modifications of the otherwise applicable BAT effluent limitations, if a discharger is fundamentally different with respect to the factors specified in CWA Section 304 (other than costs) from those considered by EPA in establishing the effluent limitations. CWA Section 301(n) also defined the conditions under which EPA may establish alternative requirements. Under Section 301(n), an application for approval of a FDF variance must be based solely on (1) information submitted during rulemaking raising the factors that are fundamentally different or (2) information the applicant did not have an opportunity to submit. The alternate limitation must be no less stringent than justified by the difference and must not result in markedly more adverse non-water quality environmental impacts than the national limitation.

EPA regulations at 40 CFR part 125, subpart D, authorizing the regional administrators to establish alternative

[93] For the purposes of this rulemaking, EPA is considering the following terms related to analytical method sensitivity to be synonymous: "quantitation limit," "reporting limit," "level of quantitation," and "minimum level."

limitations, further detail the substantive criteria used to evaluate FDF variance requests for direct dischargers. Thus, 40 CFR 125.31(d) identifies six factors (e.g., volume of process wastewater, age and size of a discharger's facility) that may be considered in determining if a discharger is fundamentally different. The Agency must determine whether, based on one or more of these factors, the discharger in question is fundamentally different from the dischargers and factors considered by EPA in developing the nationally applicable effluent guidelines. The regulation also lists four other factors (e.g., inability to install equipment within the time allowed or a discharger's ability to pay) that may not provide a basis for an FDF variance. In addition, under 40 CFR 125.31(b)(3), a request for limitations less stringent than the national limitation may be approved only if compliance with the national limitations would result in either (a) a removal cost wholly out of proportion to the removal cost considered during development of the national limitations, or (b) a non-water quality environmental impact (including energy requirements) fundamentally more adverse than the impact considered during development of the national limits. The legislative history of Section 301(n) underscores the necessity for the FDF variance applicant to establish eligibility for the variance. EPA's regulations at 40 CFR 125.32(b)(1) impose this burden upon the applicant. The applicant must show that the factors relating to the discharge controlled by the applicant's permit that are claimed to be fundamentally different are, in fact, fundamentally different from those factors considered by EPA in establishing the applicable guidelines. In practice, very few FDF variances have been granted for past ELGs. An FDF variance is not available to a new source subject to NSPS. *DuPont* v. *Train,* 430 U.S. 112 (1977).

2. Economic Variances

Section 301(c) of the CWA authorizes a variance from the otherwise applicable BAT effluent guidelines for nonconventional pollutants due to economic factors. The request for a variance from effluent limitations developed from BAT guidelines must normally be filed by the discharger during the public notice period for the draft permit. Other filing periods may apply, as specified in 40 CFR 122.21(m)(2). Specific guidance for this type of variance is provided in "Draft Guidance for Application and Review of Section 301(c) Variance Requests," dated August 21, 1984, available on EPA's Web site at *http://www.epa.gov/npdes/pubs/OWM0469.pdf.*

*3. Water Quality Variances*

Section 301(g) of the CWA authorizes a variance from BAT effluent guidelines for certain nonconventional pollutants due to localized environmental factors. These pollutants include ammonia, chlorine, color, iron, and total phenols. As this proposed rule would not establish limitations or standards for any of these pollutants, this variance would not be applicable to this particular rule.

*4. Removal Credits*

Section 307(b)(1) of the CWA establishes a discretionary program for POTWs to grant "removal credits" to their indirect dischargers. Removal credits are a regulatory mechanism by which industrial users may discharge a pollutant in quantities that exceed what would otherwise be allowed under an applicable categorical pretreatment standard because it has been determined that the POTW to which the industrial user discharges consistently treats the pollutant. EPA has promulgated removal credit regulations as part of its pretreatment regulations. See 40 CFR 403.7. These regulations provide that a POTW may give removal credits if prescribed requirements are met. The POTW must apply to and receive authorization from the Approval Authority. To obtain authorization, the POTW must demonstrate consistent removal of the pollutant for which approval authority is sought. Furthermore, the POTW must have an approved pretreatment program. Finally, the POTW must demonstrate that granting removal credits will not cause the POTW to violate applicable federal, state, or local sewage sludge requirements. 40 CFR 403.7(a)(3).

The United States Court of Appeals for the Third Circuit interpreted the CWA as requiring EPA to promulgate the comprehensive sewage sludge regulations pursuant to CWA Section 405(d)(2)(A)(ii) before any removal credits could be authorized. *See NRDC* v. *EPA,* 790 F.2d 289, 292 (3d Cir., 1986); cert. denied., 479 U.S. 1084 (1987). Congress made this explicit in the Water Quality Act of 1987, which provided that EPA could not authorize any removal credits until it issued the sewage sludge use and disposal regulations. On February 19, 1993, EPA promulgated Standards for the Use or Disposal of Sewage Sludge, which are codified at 40 CFR part 503 (58 FR 9248). EPA interprets the Court's decision in *NRDC* v. *EPA* as only allowing removal credits for a pollutant if EPA has either regulated the pollutant in part 503 or established a concentration of the pollutant in sewage sludge below which public health and the environment are protected when sewage sludge is used or disposed.

The part 503 sewage sludge regulations allow four options for sewage sludge disposal: (1) Land application for beneficial use, (2) placement on a surface disposal unit, (3) firing in a sewage sludge incinerator, and (4) disposal in a landfill which complies with the municipal solid waste landfill criteria in 40 CFR part 258. Because pollutants in sewage sludge are regulated differently depending upon the use or disposal method selected, under EPA's pretreatment regulations the availability of a removal credit for a particular pollutant is linked to the POTW's method of using or disposing of its sewage sludge. The regulations provide that removal credits may be potentially available for the following pollutants:

(1) If POTW applies its sewage sludge to the land for beneficial uses, disposes of it in a surface disposal unit, or incinerates it in a sewage sludge incinerator, removal credits may be available for the pollutants for which EPA has established limits in 40 CFR part 503. EPA has set ceiling limitations for nine metals in sludge that is land applied, three metals in sludge that is placed on a surface disposal unit, and seven metals and 57 organic pollutants in sludge that is incinerated in a sewage sludge incinerator. 40 CFR 403.7(a)(3)(iv)(A).

(2) Additional removal credits may be available for sewage sludge that is land applied, placed in a surface disposal unit, or incinerated in a sewage sludge incinerator, so long as the concentration of these pollutants in sludge do not exceed concentration levels established in part 403, Appendix G, Table II. For sewage sludge that is land applied, removal credits may be available for an additional two metals and 14 organic pollutants. For sewage sludge that is placed on a surface disposal unit, removal credits may be available for an additional seven metals and 13 organic pollutants. For sewage sludge that is incinerated in a sewage sludge incinerator, removal credits may be available for three other metals 40 CFR 403.7(a)(3)(iv)(B).

(3) When a POTW disposes of its sewage sludge in a municipal solid waste landfill that meets the criteria of 40 CFR part 258, removal credits may be available for any pollutant in the POTW's sewage sludge. 40 CFR 403.7(a)(3)(iv)(C).

## XVII. 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 Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in Chapter 12 of the BCA report. A copy of the analysis is available in the docket for this action and the analysis is briefly summarized here.

Table XVII–1 (drawn from Table 12–1 of the BCA report) provides the results of the benefit-cost analysis with both costs and benefits annualized over 24 years and discounted using a 3 percent discount rate. The table lists the eight options in order of increasing total social costs.

TABLE XVII–1—TOTAL MONETIZED ANNUALIZED BENEFITS AND COSTS OF THE BAT AND PSES REGULATORY OPTIONS

[Millions 2010 $, 3 percent discount rate] [a]

| Regulatory option | Total social costs [b] | Total monetized benefits [c d e] |
|---|---|---|
| Option 3a | $185.2 | (e) |
| Option 1 | 268.3 | $82.0 |
| Option 3b | 281.4 | (e) |
| Option 2 | 386.8 | 111.7 |
| Option 3 | 572.0 | 311.7 |
| Option 4a | 954.1 | (e) |
| Option 4 | 1,381.2 | 605.5 |
| Option 5 | 2,328.8 | 434.1 |

[a] All costs and benefits were annualized over 24 years and using a 3 percent discount rate.

[b] Total social costs include compliance costs to facilities.

[c] Mean benefit estimates. Values include partial human health benefits only for reaches that receive direct discharges from steam electric plants. Values for Options 1, 2, and 5 do not include air-related benefits.

[d] EPA estimated certain benefits for Options 3 and 4 only. Total benefits for Options 1, 2, and 5 are therefore understated. See Section XIV and Table XIV–8.

[e] EPA did not estimate benefits for Options 3a, 3b and 4a. The benefits of Option 4a are expected to be between those of Options 3 and 4.

EPA also analyzed the employment effects of the proposed ELGs. The results of that analysis are summarized in Section XI.E.

*B. Paperwork Reduction Act*

This action does not impose any new information collection burden. However, the Office of Management and Budget (OMB) has previously approved the information collection requirements contained in the existing regulations 40 CFR part 423 under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control number 2040–0281. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

EPA estimated small changes in monitoring costs due to additional metals for which EPA is proposing limits and standards; the Agency accounted for these costs as part of its analysis of the economic impacts of the proposed ELGs. However, plants will also realize certain savings by no longer monitoring effluent that would cease to exist under the proposed ELGs. The net changes in monitoring and reporting are expected to be minimal, and EPA consequently did not revise its information collection burden estimate.

EPA does not believe that the proposed rule would lead to additional costs to permitting authorities. The proposed rule would not change permit application requirements or the associated review, it would not increase the number of permits issued to steam electric plants, and nor it increase the efforts involved in developing or reviewing such permits. In the absence of nationally applicable BAT requirements, as appropriate, permitting authorities are directed to establish technology-based effluent limitations using their use best professional judgment (BPJ) to establish site-specific requirements. EPA has data that demonstrates that permitting authorities that establish technology-based effluent limitations on a BPJ basis based on site-specific conditions can spend significant time effort and resources doing so. Establishing nationally applicable BAT requirements that eliminate the need to develop BPJ-based limitations would make permitting easier and less costly in this respect. As explained in Section XVI, under this rule, permitting authorities would be required to determine, for one permit cycle, on a facility-specific basis, what date is "as soon as possible." This one-time burden, however, would be no more excessive than the existing burden to develop technology-based effluent limitations on a BPJ basis; in fact, it would likely be less burdensome. Nevertheless, EPA conservatively estimated no net change (i.e., increase or decrease) in the cost burden to federal or state governments associated with this proposal.

*C. Regulatory Flexibility Act*

The Regulatory Flexibility Act (RFA) 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 These Proposed ELGs

For purposes of assessing the impacts of this proposed rule on small entities, small entity is defined as either a: (1) A small business as defined by the Small Business Administration's (SBA) 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 less than 50,000; or (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. In reaching entity size determinations, EPA assumed that all federal or state entities owning steam electric plants affected by this rulemaking are not small entities.

The SBA criteria for identifying small, non-government entities in the electric power industry are as follows:

- For non-government entities with electric power generation as a primary business, small entities are those with total annual electric output less than 4 million MWh;
- For non-federal or state jurisdictions, small entities are those with a population of less 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 Table XVII–2).

TABLE XVII–2—NAICS CODES AND SBA ENTITY SIZE STANDARDS FOR STEAM ELECTRIC GENERATORS WITH A PRIMARY BUSINESS OTHER THAN ELECTRIC POWER GENERATION [a]

| NAICS Code | NAICS description | SBA size standard [b] |
|---|---|---|
| 211111 | Crude Petroleum and Natural Gas Extraction | 500 Employees. |
| 212111 | Bituminous Coal and Lignite Surface Mining | 500 Employees. |
| 213112 | Support Activities for Oil and Gas Operations | $7 million in revenue. |
| 221210 | Natural Gas Distribution | 500 Employees. |
| 221310 | Water Supply and Irrigation Systems | $7 million in revenue. |
| 221330 | Steam and Air-Conditioning Supply | $12.5 million in revenue. |
| 237130 | Power and Communication Line and Related Structures Construction | $33.5 million in revenue. |
| 324110 | Petroleum Refineries | 1,500 Employees. |
| 332410 | Power Boiler and Heat Exchanger Manufacturing | 500 Employees. |
| 333611 | Turbine and Turbine Generator Set Unit Manufacturing | 1,000 Employees. |
| 423510 | Metal Service Centers and Other Metal Merchant Wholesalers | 100 Employees. |
| 486110 | Pipeline Transportation of Crude Oil | 1,500 Employees. |
| 522110 | Commercial Banking | $175 million in assets. |
| 523110 | Investment Banking and Securities Dealing | $7 million in revenue. |
| 523910 | Miscellaneous Intermediation | $7 million in revenue. |
| 523920 | Portfolio Management | $7 million in revenue. |
| 524113 | Direct Life Insurance Carriers | $7 million in revenue. |
| 524126 | Direct Property and Casualty Insurance Carriers | 1,500 employees. |
| 525910 | Open-End Investment Funds | $7 million in revenue. |
| 541614 | Process, Physical Distribution and Logistics Consulting Services | $14 million in revenue. |
| 541690 | Other Scientific and Technical Consulting Services | $14 million in revenue. |
| 551111 | Offices of Bank Holding Companies | $7 million in revenue. |
| 551112 | Offices of Other Holding Companies | $7 million in revenue. |
| 562219 | Other Nonhazardous Waste Treatment and Disposal | $12.5 million in revenue.[c] |

[a] Certain plants affected by this rulemaking are owned by non-government entities whose primary business is not electric power generation.
[b] Based on size standards effective at the time EPA conducted this analysis (SBA size standards, effective October 1, 2012).
[c] EPA is aware that SBA revised the size standard applicable to this sector, effective January 7, 2013 (from $12.5 million in revenue to $35.5 million in revenue); EPA used the size standards effective at the time the analyses were completed and will update the size standards as part of revisions to support final rulemaking.

EPA identified the domestic parent entity of each steam electric plant and obtained the entity's revenue from the Steam Electric industry survey or from publicly available data sources. In this analysis, the domestic parent entity associated with any given plant is defined as that entity that has the largest ownership share in the plant. To determine whether these entities are small entities based on the size criteria outlined above, EPA compared the relevant measure for the identified parent entities to the appropriate SBA size criterion.

EPA used alternative sample-weighting approaches, which provide a range of estimates of the numbers of small entities and affected plants owned by these small entities (see Chapter 8 in the RIA for details of methodology used to develop weighted estimates). The results of this analysis using both weighting approaches are summarized below.

EPA estimates that 243 to 507 entities own steam electric plants subject to this proposal. Applying the small entity identification criteria, EPA estimates that 97 to 170 of these entities are small (see Table XVII–3). Municipalities make up the largest number of small entities owning steam electric plants under the lower bound estimate (37 out of 97) and are also a significant fraction of small entities under the upper bound estimate (46 out of 170). Small entities owning steam electric plants as a percentage of total entities range, by ownership category, from 14 to 17 percent for other political subdivision, to 47 to 51 percent for nonutility and 45 to 57 percent for municipality.

EPA determined that 14 small entities own steam electric plants expected to incur compliance costs under at least one of the eight regulatory options, for either of the two bounding cases.

TABLE XVII–3—NUMBER OF ENTITIES OWNING STEAM ELECTRIC PLANTS BY SECTOR AND SIZE

[Assuming two different ownership cases] [a]

| Ownership type | Lower bound estimate of number of entities owning steam electric plants [b] | | | Upper bound estimate of number of entities owning steam electric plants [b] | | |
|---|---|---|---|---|---|---|
| | Total | Small [c] | % Small | Total | Small [c] | % Small |
| Investor-Owned Utilities | 97 | 27 | 27.8 | 244 | 64 | 26.3 |
| Nonutilities | 35 | 18 | 51.4 | 73 | 34 | 46.8 |
| Rural Electric Cooperatives | 30 | 13 | 43.3 | 52 | 21 | 40.7 |
| Municipality | 65 | 37 | 56.9 | 101 | 46 | 45.3 |
| Other Political Subdivision | 12 | 2 | 16.7 | 30 | 4 | 14.2 |
| Federal [a] | 2 | 0 | 0.0 | 4 | 0 | 0.0 |
| State [a] | 2 | 0 | 0.0 | 2 | 0 | 0.0% |
| Tribal | 0 | 0 | N/A | 0 | 0 | N/A |
| All Entity Types | 243 | 97 | 39.9 | 507 | 170 | 33.5 |

[a] In 19 instances, a plant is owned by a joint venture of two entities; in one instance, the plant is owned by a joint venture of three entities.

[b] Of these, 92 entities, 14 of which are small, own steam electric plants that are expected to incur compliance costs under at least one regulatory option under both Case 1 and Case 2.
[c] EPA was unable to determine size for 10 parent entities; for this analysis, these entities are assumed to be small.

In total, small entities own a total of 189 steam electric plants, or 18 percent of the total universe of 1,079 steam electric plants. Of these, EPA determined that 14 plants may incur compliance costs under at least one of the eight regulatory options.

EPA notes that its proposal (discussed in Section VIII) to set the BAT equal to BPT for existing generating units with a total nameplate generating capacity of 50 MW or less for all of the eight proposed regulatory options will reduce the potential impacts of the proposed rule on small entities and municipalities. The rulemaking record indicates that establishing a size threshold for the BAT would preferentially minimize some of the economic impacts expected on municipalities and small entities. This is the result, in particular, of the fact that 37 percent of small entities own a steam electric generating unit with a capacity of 50 MW or smaller. This stands in contrast to the 22 percent of all firms (both large and small entities) that own such a unit and the 18 percent of large entities that own one. Moreover, more than half (54 percent) of generating units owned by small entities are 50 MW or smaller. In contrast, only seven percent of generating units owned by large entities are 50 MW or smaller. Municipalities also tend to own smaller generating units, with 30 percent of municipalities and 42 percent of municipal-owned units being affected by the 50 MW size threshold.

EPA requests comment on the proposed 50 MW threshold applicable to discharges of the wastestreams described under each of the preferred options, and as well as other possible thresholds for small units.

2. Statement of Basis

As described above, EPA began its assessment of the impact of regulatory options on small entities by first estimating the number of small entities owning Steam Electric plants that would be subject to these proposed ELGs. EPA then assessed whether these small entities would be expected to incur costs that constitute a significant impact; and whether the number of those small entities estimated to incur a significant impact represent a substantial number of small entities.

To assess whether small entities' compliance costs might constitute a significant impact, EPA summed annualized compliance costs for the steam electric plants determined to be owned by a given small entity and calculated these costs as a percentage of entity revenue (cost-to-revenue test). EPA compared the resulting percentages to impact criteria of 1 percent and 3 percent of revenue. Small entities estimated to incur compliance costs exceeding one or more of the 1 percent and 3 percent impact thresholds were identified as potentially incurring a significant impact.

EPA used alternative sample-weighting approaches, which provide a range of estimates of the numbers of small entities and steam electric plants owned by these small entities. The results of this analysis using both weighting approaches are summarized below. Table XVII–4 presents the estimated numbers of small entities incurring costs exceeding 1 percent and 3 percent of revenue. For more information on this analysis in general and the weighting approaches in particular, see Chapter 7 in the RIA report.

TABLE XVII–4—ESTIMATED COST-TO-REVENUE IMPACT ON SMALL ENTITIES OWNING STEAM ELECTRIC PLANTS SUBJECT TO THIS PROPOSED RULE

[Excluding those below the size threshold]

| Regulatory option | Cost ≥1% of revenue | | Cost ≥3% of revenue | |
|---|---|---|---|---|
| | Number of small entities | % of small affected entities [b] | Number of small entities [a] | % of small affected entities [b] |
| **Lower bound estimate of number of entities owning steam electric plants** | | | | |
| Option 3a | 0 | 0.0 | 0 | 0.0 |
| Option 3b | 0 | 0.0 | 0 | 0.0 |
| Option 1 | 3 | 3.1 | 3 | 3.1 |
| Option 2 | 5 | 5.2 | 3 | 3.1 |
| Option 3 | 5 | 5.2 | 3 | 3.1 |
| Option 4a | 6 | 6.2 | 4 | 4.1 |
| Option 4 | 12 | 12.4 | 4 | 4.1 |
| Option 5 | 12 | 12.4 | 7 | 7.2 |
| **Upper bound estimate of number of entities owning steam electric plants** | | | | |
| Option 3a | 0 | 0.0 | 0 | 0.0 |
| Option 3b | 0 | 0.0 | 0 | 0.0 |
| Option 1 | 3 | 1.8 | 3 | 1.8 |
| Option 2 | 5 | 2.9 | 3 | 1.8 |
| Option 3 | 5 | 2.9 | 3 | 1.8 |
| Option 4a | 6 | 3.5 | 4 | 2.4 |
| Option 4 | 12 | 7.1 | 4 | 2.4 |
| Option 5 | 12 | 7.1 | 7 | 4.1 |

[a] The number of entities with cost-to-revenue ratios exceeding 3 percent is a subset of the number of entities with such ratios exceeding 1 percent.
[b] Percentage values were calculated relative to the total of 97 (Case 1) and 170 (Case 2) small entities owning steam electric plants.

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As reported in Table XVII–4, EPA estimates that between 0 and 12 small entities owning steam electric plants will incur costs exceeding 1 percent of revenue, and that between 0 and 7 small entities owning steam electric plants will incur costs exceeding 3 percent of revenue, depending on the regulatory option. This is out of an estimated total of 97 to 170 small entities owning steam electric plants. The impact findings in terms of *numbers* of entities affected at different levels, and the *percentage* of small entities by ownership category vary by regulatory option. Overall across entity types, no small entity is estimated to have costs exceeding 1 percent of revenue under Options 3a and 3b. Under Option 3, 5 small entities are estimated to have costs exceeding 1 percent of revenue, and 3 small entities have costs exceeding 3 percent of revenue. Under Option 4a, 6 small entities are estimated to have costs 1 percent of revenue or higher under Option 3, and 4 small entities have costs 3 percent of revenue or higher. Table XVII–5 presents the distribution of these entities by ownership type for Options 3 and 4a (Options 3a and 3b are not included in the table since no small entity has costs 1 percent of revenue or higher under these two options). As shown in the table, small entities with costs 1 percent of revenue or greater under Option 3 include 2 cooperatives and 3 municipalities. Under Option 4a, 2 cooperatives and 4 municipalities have costs 1 percent of revenue or greater. The cost-to-revenue test is one of several metrics EPA used to determine the impacts of the proposed ELGs. As discussed in Section XI.D, EPA also looked at impacts in the context of the electricity market-level effects to assess economic achievability.

TABLE XVII–5—ESTIMATED COST-TO-REVENUE IMPACT ON SMALL ENTITIES OWNING STEAM ELECTRIC PLANTS UNDER THE PREFERRED BAT AND PSES OPTIONS (OPTIONS 3 AND 4a), BY OWNERSHIP TYPE (EXCLUDING THOSE BELOW THE SIZE THRESHOLD) [a]

| Regulatory option | Lower bound estimate of number of entities owning steam electric plants | | | | Upper bound estimate of number of entities owning steam electric plants | | | |
|---|---|---|---|---|---|---|---|---|
| | Cost ≥1% of revenue | | Cost ≥3% of revenue | | Cost ≥1% of revenue | | Cost ≥3% of revenue | |
| | Number of small entities | % of small affected entities [c] | Number of small entities [b] | % of small affected entities [c] | Number of small entities | % of small affected entities [c] | Number of small entities [b] | % of small affected entities [c] |
| Option 3: | | | | | | | | |
| Cooperative | 2 | 15.4 | 2 | 15.4 | 2 | 9.4 | 2 | 9.4 |
| Investor-Owned | 0 | 0.0 | 0 | 0.00 | 0 | 0.0 | 0 | 0.0 |
| Municipality | 3 | 8.1 | 1 | 2.7 | 3 | 6.5 | 1 | 2.2 |
| Nonutility | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| Other Political Subdivision | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| Total | 5 | 5.2 | 3 | 3.1 | 5 | 2.9 | 3 | 1.8 |
| Option 4a: | | | | | | | | |
| Cooperative | 2 | 15.4 | 2 | 15.4 | 2 | 9.4 | 2 | 9.4 |
| Investor-Owned | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| Municipality | 4 | 10.8 | 2 | 5.4 | 4 | 8.7 | 2 | 4.4 |
| Nonutility | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| Other Political Subdivision | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| Total | 6 | 6.2 | 4 | 4.1 | 6 | 3.5 | 4 | 2.4 |

[a] Options 3a and 3b are not included in the table since no small entity has costs 1 percent of revenue or higher under these two preferred options.

[b] The number of entities with cost-to-revenue ratios exceeding 3 percent is a subset of the number of entities with such ratios exceeding 1 percent.

[c] Percentage values were calculated relative to the total of 97 (Case 1) and 170 (Case 2) small entities owning steam electric plants. EPA expects that Case 2 is a more likely ownership scenario for small entities (e.g., small municipalities) as small entities may be less likely to own multiple non-surveyed steam electric plants. See RIA Chapter 8 for details.

Based on this analysis, EPA determines that the small entity impact levels for the preferred BAT and PSES options (Options 3a, 3b, 3 and 4a) support a finding of no significant impact on a substantial number of small entities (No SISNOSE). Where not zero altogether, the numbers of small entities incurring costs exceeding either the 1 or 3 percent of revenue impact threshold are small in the absolute and represent small percentages of the total estimated number of small entities (see Table XVII–5). For more details on this

analysis, see Chapter 8 of the RIA report.

3. Certification Statement

After considering the economic impacts of these proposed ELGs on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. EPA bases its finding on the low number of small entities estimated to incur costs exceeding one and/or three percent of revenue, and the small percentage that these entities represent within the total of small entities owning steam electric plants. EPA continues to be interested in the potential impacts of the proposed rule on small entities and welcomes comments on issues related to potential impacts.

*D. Unfunded Mandates Reform Act (UMRA)*

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 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. This rule contains a federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, EPA has prepared under Section 202 of the UMRA a written statement, which is summarized below (see Chapter 9 in the RIA report for more details).

Consistent with the intergovernmental consultation provisions of Section 204 of the UMRA EPA has initiated consultations with governmental entities affected by this rule. As described in Sections XVII.E, EPA held consultation meetings with elected officials or their designated employees in October 2011 to ensure their meaningful and timely input into the proposed ELGs development. EPA also conducted outreach with several intergovernmental associations representing elected officials. As described in Section XVII.F, EPA also initiated consultation and coordination with federally-recognized tribal governments in August 2011 and continued this government-to-government dialogue in March 2012.

Consistent with Section 205, EPA has identified and considered a reasonable number of regulatory alternatives. EPA considered and analyzed several alternative regulatory options to determine BAT/BADCT. These regulatory options are discussed in Section VIII of this preamble. These options included a range of technology-based approaches. As discussed in detail in Section VIII, EPA is proposing Options 3a, 3b, 3 and 4a as the preferred BAT and PSES options because they are technologically available, economically achievable, and have acceptable non-water quality environmental impacts. EPA is proposing Option 4 as the preferred NSPS and PSNS option because it is technologically available and demonstrated, poses no barrier to entry, and has acceptable non-water quality environmental impacts.

This rule is not subject to the requirements of Section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. For its assessment of the impact of compliance requirements on small governments (i.e., governments with a population of less than 50,000), EPA compared total costs and costs per plant estimated to be incurred by small governments with the costs estimated to be incurred by large governments. EPA also compared costs for small government-owned plants with those of non-government-owned facilities. The Agency evaluated both the average and maximum annualized cost per plant. Chapter 9 of the RIA report provides details of these analyses. In all of these comparisons, both for the cost totals and, in particular, for the average and maximum cost per plant, the costs for small government-owned facilities were less than those for large government-owned facilities or for small non-government-owned facilities. On this basis, EPA concludes that the compliance cost requirements of the proposed Steam Electric ELGs would not significantly or uniquely affect small governments.

*E. Executive Order 13132: Federalism*

Under Executive Order 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, 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 proposed action.

EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs.

As discussed in Section XI, EPA anticipates that this proposed action will not impose incremental administrative burden on states from issuing, reviewing, and overseeing compliance with discharge requirements. However, EPA has identified 168 steam electric plants owned by state or local government entities, out of which less than 10 percent may incur costs under one of the preferred regulatory Options. Specifically, EPA projects that five government-owned plants incur compliance costs under BAT/PSES regulatory Option 3a, six plants incur compliance costs under Option 3b, 14 plants incur compliance costs under Option 3, and 15 plants incur compliance costs under Option 4a. EPA estimates that the maximum compliance cost in any one year to governments (excluding federal government) for the eight regulatory options ranges from $13.8 million under Option 3a to $406.2 million under Option 5. Options 3b, 3 and 4a have maximum compliance costs in any one year to governments of $31.9 million, $109.5 million and $141.8 million, respectively (see Chapter 9 of the RIA report for details). From these cost values, EPA determined that the proposed ELGs contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, in any one year. Based on this information, EPA finds that the action may impose substantial direct compliance costs on state or local governments. Accordingly, EPA provides the following federalism summary impact statement as required by Section 6(b) of Executive Order 13132.

EPA consulted with elected officials or their representative national organizations early in the process of developing the proposed action to permit them to have meaningful and timely input into its development.

EPA invited government officials to a consultation meeting held on October 11, 2011. EPA conducted outreach with several intergovernmental associations representing elected officials and encouraged their members to participate in the meeting, including the National Governors Association, the National Conference of State Legislatures, the Council of State Governments, the National Association of Counties, the National League of Cities, the U.S. Conference of Mayors, the County Executives of America and the National Associations of Towns and Townships.

Over 50 participants attended the consultation by phone and another 20 attended the meeting in person. EPA representatives were also present. Participants raised concerns during the meeting and in written comments

regarding the technology options, pollutant removal effectiveness, costs of specific technologies and overall costs, impacts on small generating units and on small governments, and generally requested more detailed information. They also expressed their concern with regulating the industry at this time given the difficult economic conditions.

As explained in Section VIII, under all eight proposed regulatory options, EPA is proposing differentiated requirements for oil-fired generating units and units 50 MW or less. EPA believes these differentiated requirements will alleviate some of the concerns raised above. Further, as explained in Section XI, EPA's analysis demonstrates that the proposed requirements are economically achievable for the steam electric industry as a whole and for plants owned by state or local government entities. EPA is including in the docket for this action a memorandum that provides a response to the comments it received through this consultation. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on the proposed ELGs from State and local officials.

*F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments*

This action does not have tribal implications, as specified in Executive Order 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 Indian tribes, or the distribution of power and responsibilities between the Federal government and Indian tribes as specified in Executive Order 13175. EPA's analyses show that no facility subject to these proposed ELGs is owned by tribal governments. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, EPA consulted with tribal officials in developing this action. EPA initiated consultation and coordination with federally recognized tribal governments in August 2011, sharing information about the steam electric effluent guidelines rulemaking with the National Tribal Caucus and the National Tribal Water Council. EPA continued this government-to-government dialogue and, in March 2012, invited tribal representatives to participate in further discussions about the rulemaking process and objectives, with a focus on identifying specific ways that the rulemaking may affect tribes. EPA mailed an invitation letter directly to those tribes that were preliminarily identified as potentially affected by the rulemaking, as well extended the invitation via email to all federally-recognized tribal governments encouraging their participation in the consultation process. The consultation process ended on April 17, 2012 and no comments were received from any tribal representative. For further information regarding the consultation process and supplemental materials provided to tribal representatives please go to the steam electric power generating effluent guidelines Web site at this link: *http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm#point8.* EPA specifically solicits additional comment on this proposed action from tribal officials.

*G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks*

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This proposed action's health and risk assessments are summarized in Section XIV.D.

*H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use*

This action is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

The Agency analyzed the potential energy effects of these proposed ELGs. The potentially significant effects of this rule on energy supply, distribution or use concern the electric power sector. EPA's analysis found that the proposed ELGs would not cause effects in the electric power sector that would constitute a significant adverse effect under Executive Order 13211. Namely, the Agency's analysis found that this rule would not reduce electricity production in excess of 1 billion kilowatt hours per year or in excess of 500 megawatts of installed capacity, and therefore would not constitute a significant regulatory action under Executive Order 13211.

For more detail on the potential energy effects of this proposal, see Chapter 10 in the RIA report.

*I. National Technology Transfer and Advancement Act*

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, 12(d) (15 U.S.C. 272 note), directs EPA to use voluntary consensus standards in its regulatory activities unless to do 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. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking does not involve technical standards, for example, in the measurement of pollutant loads. Nothing in this proposed rule would prevent the use of voluntary consensus standards for such measurement where available, and EPA encourages permitting authorities and regulated entities to do so. Therefore, EPA is not considering the use of any voluntary consensus standards.

*J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations*

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

To meet the objectives of Executive Order 12898, EPA examined whether these proposed ELGs will have potential environmental justice concerns in the areas affected by steam electric plant

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discharges. The Agency analyzed the demographic characteristics of the populations currently exposed to steam electric plant discharges through receiving reaches (i.e., populations located within 100 miles of the affected reaches, also referred to as the "benefit regions" in the rest of this discussion) to determine whether minority and or low-income populations are subject to disproportionally high environmental impacts. Chapter 10 of the RIA provides a detailed discussion of the environmental justice analysis.

EPA compared demographic data from the 2010 Census for benefit regions with corresponding characteristics at the state and national levels. This analysis focuses on the spatial distribution of minority and low-income groups to determine whether these groups are more or less represented in the populations expected to benefit from the proposed ELGs. The demographic characteristics that EPA analyzed include: percent African Americans, percent Native American, Eskimo, or Aleut, percent Asian or Pacific Islander, percent of the population below the poverty level, and median income. This analysis shows that approximately 14 percent of households in affected populations are below the poverty threshold, and 25 percent of them are minority, compared with national averages of 14 percent and 36 percent, respectively. Additionally, the median household income in affected populations is $48,579, while it is $51,914 nationally.

Of the 344 benefit regions defined in the analysis (within 100 miles of an affected plant), 28 regions (8 percent) may have Environmental Justice concerns under all three metrics, 79 regions (23 percent) under two metrics, and 194 regions (56 percent) under one metric. Forty-three regions (13 percent) would not be considered has having Environmental Justice concerns under any of the metrics.

This analysis indicates that minority and low-income communities are expected to benefit as much as anyone from the proposed ELGs.

## Appendix A: Definitions, Acronyms, and Abbreviations Used in This Notice

The following acronyms and abbreviations are used in this document.

*Administrator*—The Administrator of the U.S. Environmental Protection Agency.

*Agency*—U.S. Environmental Protection Agency.

*BAT*—Best available technology economically achievable, as defined by Sections 301(b)(2)(A) and 304(b)(2)(B) of the CWA.

*BCT*—The best control technology for conventional pollutants, applicable to discharges of conventional pollutants from existing industrial point sources, as defined by Sections 301(b)(2)(E) and 304(b)(4) of the CWA.

*BMP*—Best management practice.

*Bottom ash*—The ash, including boiler slag, that drops out of the furnace gas stream in the furnace and which settles in the furnace or are dislodged from furnace walls. Economizer ash is included when it is collected with bottom ash.

*BPT*—The best practicable control technology currently available, applicable to effluent limitations, for industrial discharges to surface waters, as defined by Sections 301(b)(1) and 304(b)(1) of the CWA.

*CBI*—Confidential Business Information.

*CCR*—Coal Combustion Residuals.

*Clean Water Act (CWA)*—The Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. Section 1251 *et seq.*), as amended *e.g.,* by the Clean Water Act of 1977 (Pub. L. 95–217), and the Water Quality Act of 1987 (Pub. L. 100–4).

*Combustion Residual Leachate*—Leachate from landfills or surface impoundments containing combustion residuals. Leachate includes liquid, including any suspended or dissolved constituents in the liquid that has percolated through or drained from waste or other materials emplaced in a landfill, or that pass through the containment structure (e.g., bottom, dikes, berms) of a surface impoundment. Leachate also includes the terms seepage, leak, and leakage, which are generally used in reference to leachate from an impoundment. Includes landfills and surface impoundments located on non-adjoining property when under the operational control of the permitted facility.

*Direct Discharger*—A facility that discharges or may discharge treated or untreated wastewaters into waters of the United States.

*DOE*—Department of Energy.

*Dry bottom ash handling system*—A system that does not use water to convey bottom ash away from the boiler. It includes systems that collect and convey the ash without any use of water, as well as systems in which bottom ash is mechanically or pneumatically conveyed away from the boiler.

*Dry fly ash handling system*—A system that does not use water as the transport medium to convey fly ash away from particulate collection equipment.

*EIA*—Energy Information Administration.

*EO*—Executive Order.

*EPA*—U.S. Environmental Protection Agency.

Facility — *All property owned, operated, leased, or under the control of the same person or entity.*

*Flue Gas Desulfurization (FGD) Wastewater*—Any process wastewater generated specifically from the wet flue gas desulfurization scrubber system, including any solids separation or solids dewatering processes.

*Flue Gas Mercury Control (FGMC) System*—An air pollution control system installed or operated for the purpose of removing mercury from flue gas.

*Flue Gas Mercury Control Wastewater*—Any process wastewater generated from an air pollution control system installed or operated for the purpose of removing mercury from flue gas. This includes fly ash collection systems when the particulate control system follows the injection of sorbents or implementation of other controls to remove mercury from flue gas. Flue gas desulfurization systems are not included in this definition.

*Fly Ash*—The ash that is carried out of the furnace by the gas stream and collected by mechanical precipitators, electrostatic precipitators, and/or fabric filters. Economizer ash is included when it is collected with fly ash. Ash collected in wet scrubber air pollution control systems whose primary purpose is particulate removal is not included.

*Gasification Wastewater*—Wastewater from all sources at an integrated gasification combined cycle operation except those for which specific limitations are otherwise established. Gasification wastewater includes, but is not limited to the following: slag handling wastewater; fly ash and water stream; sour/grey water (which consists of condensate generated for gas cooling, as well as other wastestreams); $CO_2$/steam stripper wastewater; air separation unit blowdown; and sulfur recover unit blowdown.

*IPM*—Integrated Planning Model.

*Landfill*—A disposal facility or part of a facility where solid waste, sludges, or other process residuals are placed in or on any natural or manmade formation in the earth for disposal and which is not a storage pile, a land treatment facility, a surface impoundment, an underground injection well, a salt dome or salt bed formation, an underground mine, a cave, or a corrective action management unit.

*Low Volume Waste Sources*—Wastewater from all sources including, but not limited to: ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, boiler blowdown, floor drains, cooling tower basin cleaning wastes, and recirculating house service water systems. Sanitary and air conditioning wastes and carbon capture wastewater are not included.

*NAICS*—North American Industry Classification System.

*NSPS, or New Source Performance Standards,* applicable to industrial facilities whose construction is begun after the effective date of the final regulations. See 40 CFR 122.2.

*ORCR*—Office of Resource Conservation and Recovery.

*PSES*—Pretreatment Standards for Existing Sources.

*PSNS*—Pretreatment Standards for New Sources.

*Publicly Owned Treatment Works (POTW)*—Any device or system, owned by a state or municipality, used in the treatment (including recycling and reclamation) of municipal sewage or industrial wastes of a liquid nature that is owned by a state or municipality. This includes sewers, pipes, or other conveyances only if they convey wastewater to a POTW providing treatment. See 40 CFR 122.2.

*RCRA*—The Resource Conservation and Recovery Act of 1976, 42 U.S.C. 6901 *et seq.*

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*RFA*—Regulatory Flexibility Act.

*SBA*—Small Business Administration.

*Surface Impoundments*—A facility or part of a facility which is a natural topographic depression, man-made excavation, or diked or dammed area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquid process wastes or process wastes containing free liquids, and which is not an injection well. Examples of surface impoundments are holding, storage, settling, and aeration pits, ponds, and lagoons.

*UMRA*—Unfunded Mandates Reform Act.

*Wet bottom ash handling system*—A system in which bottom ash is conveyed away from the boiler using water as a transport medium. Wet bottom ash systems typically send the ash slurry to dewatering bins or a surface impoundment.

*Wet FGD system*—Wet FGD systems capture sulfur dioxide from the flue gas using a sorbent that has mixed with water to form a wet slurry, and that generates a water stream that exits the FGD scrubber absorber.

*Wet fly ash handling system*—A system that conveys fly ash away from particulate removal equipment using water as a transport medium. Wet fly ash systems typically dispose of the ash slurry in a surface impoundment.

### List of Subjects 40 CFR Part 423

Environmental protection, Electric power generation, Power plants, Waste treatment and disposal, Water pollution control.

Dated: April 19, 2013.

**Bob Perciasepe,**

*Acting Administrator.*

Therefore, 40 CFR chapter I is proposed to be amended as follows:

## PART 423—STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

■ 1. The authority citation for part 423 is revised to read as follows:

**Authority:** Secs. 101; 301; 304(b), (c), (e), and (g); 306; 307; 308 and 501, Clean Water Act (Federal Water Pollution Control Act Amendments of 1972, as amended; 33 U.S.C. 1251; 1311; 1314(b), (c), (e), and (g); 1316; 1317; 1318 and 1361).

■ 2. Section 423.10 is revised as follows:

### § 423.10 Applicability.

The provisions of this part apply to discharges resulting from the operation of a generating unit by an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation, and which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (e.g., petroleum coke, synthesis gas), or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium. This part applies to discharges associated with both the combustion turbine and steam turbine portions of a combined cycle generating unit. Facilities defined as new sources under the 1982 new source performance standards specified in §§ 423.15(a) and 423.17(a) of this part continue to be subject to those standards. Units that qualify as 1982 new sources are also subject to revised BAT effluent limitations specified in § 423.13 of this part (for direct dischargers) or the revised pretreatment standards specified in § 423.16 of this part (for indirect dischargers). These revised limitations and standards constitute amendments to the new source performance standards applicable to 1982 new sources.

■ 3. Section 423.11 is amended by:

■ a. Revising paragraphs (b) and (e); and

■ b. Adding paragraphs (n) through (u).

The revised and added paragraphs read as follows:

### § 423.11 Specialized definitions.

* * * * *

(b) The term low volume waste sources means, taken collectively as if from one source, wastewater from all sources except those for which specific limitations are otherwise established in this part. Low volume waste sources include, but are not limited to, the following: wastewaters from ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, boiler blowdown, floor drains, cooling tower basin cleaning wastes, recirculating house service water systems, and wet scrubber air pollution control systems whose primary purpose is particulate removal. Sanitary wastes, air conditioning wastes, and wastewater from carbon capture or sequestration systems are not included in this definition.

* * * * *

(e) The term fly ash means the ash that is carried out of the furnace by a gas stream and collected by a capture device such as a mechanical precipitator, electrostatic precipitator, or fabric filter. Economizer ash is included in this definition when it is collected with fly ash. Ash is not included in this definition when it is collected in wet scrubber air pollution control systems whose primary purpose is particulate removal.

* * * * *

(n) The term flue gas desulfurization (FGD) wastewater means any process wastewater generated from a wet flue gas desulfurization scrubber system, including any solids separation or solids dewatering processes.

(o) The term flue gas mercury control wastewater means any process wastewater generated from an air pollution control system installed or operated for the purpose of removing mercury from flue gas. This includes fly ash collection systems when the particulate control system follows the injection of sorbents or implementation of other controls to remove mercury from flue gas. Flue gas desulfurization systems are not included in this definition.

(p) The term transport water means any process wastewater that is used to convey fly ash or bottom ash from the ash collection equipment and has direct contact with the ash.

(q) The term gasification wastewater means any process wastewater generated from a system used to create synthesis gas from fuels such as coal or petroleum coke. Gasification wastewater includes, but is not limited to, the following: slag handling wastewater, sour/grey water (which includes condensate generated for gas cooling, as well as other wastestreams), $CO_2$/steam stripper wastewater, air separation unit blowdown, and sulfur recovery unit blowdown.

(r) The term combustion residual leachate means leachate from landfills or surface impoundments containing residuals from the combustion of fossil or fossil-derived fuel. Leachate includes liquid, including any suspended or dissolved constituents in the liquid, that has percolated through or drained from waste or other materials placed in a landfill, or that pass through the containment structure (e.g., bottom, dikes, berms) of a surface impoundment. Leachate also includes the terms seepage, leak, and leakage, which are generally used in reference to leachate from an impoundment.

(s) The term oil-fired unit means a generating unit that uses oil as the primary or secondary fuel source and does not use a gasification process or any coal or petroleum coke as a fuel source. This definition does not include units that use oil only for start up or flame-stabilization purposes.

(t) The term sufficiently sensitive analytical method means a method that ensures the sample-specific quantitation level for the wastewater being analyzed is at or below the level of the effluent limitation.

(u) The term nonchemical metal cleaning waste means any wastewater resulting from the cleaning of any metal process equipment without chemical cleaning compounds, including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning.

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■ 4. Section 423.12 is amended by:

■ a. Revising paragraphs (b)(11) and (12); and

■ b. Adding paragraph (b)(13).

The revised and added paragraphs read as follows:

**§ 423.12 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available (BPT).**

* * * * *

(b) * * *

(11) The quantity of pollutants discharged in FGD wastewater, flue gas mercury control wastewater, combustion residual leachate, or gasification wastewater shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration listed in the following table:

| Pollutant or pollutant property | BPT effluent limitations | |
|---|---|---|
| | Maximum for any 1 day (mg/l) | Average of daily values for 30 consecutive days shall not exceed (mg/l) |
| TSS | 100.0 | 30.0 |
| Oil and grease | 20.0 | 15.0 |

(12) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of the any mass based limitations specified in paragraphs (b)(3) through (b)(11) of this section. Concentration limitations shall be those concentrations specified in this section.

(13) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (b)(1) through (b)(12) of this section attributable to each controlled waste source shall not exceed the specified limitations for that waste source.

■ 5. Section 423.13 is amended by:

■ a. Adding paragraph (f);

■ b. Revising paragraphs (g) and (h); and

■ c. Adding paragraphs (i) through (n).

**§ 423.13 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT).**

* * * * *

(f)(1) Except for those discharges to which paragraph (f)(2) of this section applies, the quantity of pollutants discharged in nonchemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of nonchemical metal cleaning wastes times the concentration listed in the following table:

| Pollutant or pollutant property | BAT effluent limitations | |
|---|---|---|
| | Maximum for any 1 day (mg/l) | Average of daily values for 30 consecutive days shall not exceed (mg/l) |
| Copper, total | 1.0 | 1.0 |
| Iron, total | 1.0 | 1.0 |

(2) For those discharges of nonchemical metal cleaning waste that are currently authorized pursuant to limitations based on requirements in § 423.12(b)(3) for low-volume waste, the quantity of pollutants discharged in nonchemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of nonchemical metal cleaning wastes times the concentration listed in § 423.12(b)(3).

(g)(1) Except for those discharges to which paragraph (g)(2) of this section applies, dischargers must meet the effluent limitations in this paragraph by a date determined by the permitting authority that is as soon as possible within the next permit cycle beginning July 1, 2017. These effluent limitations apply to pollutants in FGD wastewater generated on or after the date the permitting authority has determined is as soon as possible. Such effluent limitations shall not allow the quantity of pollutants in FGD wastewater to exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the following table:

| Pollutant or pollutant property | BAT effluent limitations | |
|---|---|---|
| | Maximum for any 1 day | Average of daily values for 30 consecutive days shall not exceed |
| Arsenic, total (ug/L) | 8 | 6 |
| Mercury, total (ng/L) | 242 | 119 |
| Selenium, total (ug/L) | 16 | 10 |
| Nitrate/nitrate as N (mg/L) | 0.17 | 0.13 |

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(2) For any electric generating unit with a total nameplate capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in § 423.12(b)(11).

(3) A discharger must demonstrate compliance with the effluent limitations in paragraph (g)(1) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the FGD wastewater in any other plant process or commingling of the FGD wastewater with any water or other process wastewater, except for any combustion residual leachate or any other FGD wastewater. Compliance with the effluent limitations must reflect results obtained from sufficiently sensitive analytical methods.

**Note to (g):** All proposed revisions to § 423.13(g) reflect proposed Option 4a, Option 3, and Option 3b (for units located at facilities with a total wet-scrubbed capacity of 2,000 MW or more), only. Under proposed Option 3a and Option 3b (for units located at facilities with a total wet-scrubbed capacity of less than 2,000 MW), BAT would continue to need to be determined on a site-specific basis using best professional judgment.

(h)(1) Except for those discharges to which paragraph (h)(2) of this section applies, dischargers must meet the discharge prohibition in this paragraph by a date determined by the permitting authority that is as soon as possible within the next permit cycle beginning July 1, 2017. There shall be no discharge of wastewater pollutants from fly ash transport water generated on or after the date the permitting authority determines is as soon as possible. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in fly ash transport water shall not exceed the quantity determined by multiplying the flow of fly ash transport water times the concentration listed in § 423.12(b)(4).

(i)(1) Except for those discharges to which paragraph (i)(2) of this section applies, dischargers must meet the discharge prohibition in this paragraph by a date determined by the permitting authority that is as soon as possible within the next permit cycle beginning July 1, 2017. There shall be no discharge of wastewater pollutants from flue gas mercury control wastewater generated on or after the date the permitting authority determines is as soon as possible. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in flue gas mercury control wastewater shall not exceed the quantity determined by multiplying the flow of flue gas mercury control wastewater times the concentration listed in § 423.12(b)(11).

(j)(1) Except for those discharges to which paragraph (j)(2) of this section applies, dischargers must meet the effluent limitations in this paragraph by a date determined by the permitting authority that is as soon as possible within the next permit cycle beginning July 1, 2017. Such effluent limitations shall not allow the quantity of pollutants in gasification wastewater to exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the following table:

| Pollutant or pollutant property | BAT effluent limitations | |
|---|---|---|
| | Maximum for any 1 day | Average of daily values for 30 consecutive days shall not exceed |
| Arsenic, total (ug/L) | 4 | (1) |
| Mercury, total (ng/L) | 1.76 | 1.29 |
| Selenium, total (ug/L) | 453 | 227 |
| Total dissolved solids (mg/L) | 38 | 22 |

[1] This regulation does not specify this type of limitation for this pollutant; however, permitting authorities may do so as appropriate.

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in § 423.12(b)(11).

(3) A discharger must demonstrate compliance with the effluent limitations in paragraph (j)(1) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the gasification wastewater in any other plant process or commingling of the gasification wastewater with water or any other process wastewater. Compliance with the effluent limitations must reflect results obtained from sufficiently sensitive analytical methods.

(k)(1) Except for those discharges to which paragraph (k)(2) of this section applies, dischargers must meet the discharge prohibition in this paragraph by a date determined by the permitting authority that is as soon as possible within the next permit cycle beginning July 1, 2017. There shall be no discharge of wastewater pollutants from bottom ash transport water generated on or after the date the permitting authority determines is as soon as possible. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 400 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration in § 423.12(b)(4).

**Note to (k):** All proposed revisions to § 423.13(k) reflect proposed Option 4a, only. Under proposed Option 3, Option 3a, and Option 3b, § 423.13(k) would be revised to specify that the quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration in § 423.12(b)(4).

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(l) The quantity of pollutants discharged in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of leachate times the concentration listed in § 423.12(b)(11).

(m) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of any mass based limitations specified in paragraphs (b) through (l) of this section. Concentration limitations shall be those concentrations specified in this section.

(n) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a) through (m) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

■ 6. Section 423.15 is amended by revising paragraphs (a) and (b) to read as follows:

**§ 423.15 New source performance standards (NSPS).**

(a) 1982 New source performance standards. Any new source as of November 19, 1982, subject to this subpart, must achieve the following new source performance standards and the revised requirements of § 423.13 of this part, published on [insert date of publication of final rule]:

(1) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

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

(3) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

| NSPS | Pollutant or pollutant property | |
|---|---|---|
| | Maximum for any 1 day (mg/l) | Average of daily values for 30 consecutive days shall not exceed (mg/l) |
| TSS | 100.0 | 30.0 |
| Oil and grease | 20.0 | 15.0 |

(4) The quantity of pollutants discharged in chemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of chemical metal cleaning wastes times the concentration listed in the following table:

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum for any 1 day (mg/l) | Average of daily values for 30 consecutive days shall not exceed (mg/l) |
| TSS | 100.0 | 30.0 |
| Oil and grease | 20.0 | 15.0 |
| Copper, total | 1.0 | 1.0 |
| Iron, total | 1.0 | 1.0 |

(5) [Reserved].

(6) The quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the bottom ash transport water times the concentration listed in the following table:

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum for any1 day (mg/l) | Average of daily values for 30 consecutive days shall not exceed (mg/l) |
| TSS | 100.0 | 30.0 |
| Oil and grease | 20.0 | 15.0 |

(7) There shall be no discharge of wastewater pollutants from fly ash transport water. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(8)(i) For any plant with a total rated electric generating capacity of 25 or more megawatts, the quantity of pollutants discharged in once through cooling water from each discharge point shall not exceed the quantity determined by multiplying the flow of once through cooling water from each discharge point times the concentration listed in the following table:

| Pollutant or pollutant property | NSPS |
|---|---|
| | Maximum concentrations (mg/l) |
| Total residual chlorine ..... | 0.20 |

(ii) Total residual chlorine may not be discharged from any single generating unit for more than two hours per day unless the discharger demonstrates to the permitting authority that discharge for more than two hours is required for macroinvertebrate control. Simultaneous multi-unit chlorination is permitted.

(9)(i) For any plant with a total rated generating capacity of less than 25 megawatts, the quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water sources times the concentration listed in the following table:

| Pollutant or pollutant property | Maximum concentration (mg/l) | Average concentration (mg/l) |
|---|---|---|
| Free available chlorine ..... | 0.5 | 0.2 |

(ii) Neither free available chlorine nor total residual chlorine 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 Regional Administrator or State, if the State has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(10)(i) The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown times the concentration listed below:

| Pollutant or pollutant property | Maximum concentration (mg/l) | Average concentration (mg/l) |
|---|---|---|
| Free available chlorine ..... | 0.5 | 0.2 |

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum for any 1 day concentration (mg/l) | Average of daily values for 30 consecutive days shall not exceed (mg/l) |
| The 126 priority pollutants (Appendix A) contained in chemicals added for cooling tower maintenance, except: ..... | [1] | [1] |
| Chromium, total ..... | 0.2 | 0.2 |
| Zinc, total ..... | 1.0 | 1.0 |

[1] No detectable amount.

(ii) Neither free available chlorine nor total residual chlorine 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 Regional Administrator or State, if the State has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(iii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the limitations for the 126 priority pollutants in paragraph (a)(10)(i) of this section may be determined by engineering calculations which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136.

(11) Subject to the provisions of § 423.15(a)(12), the quantity or quality of pollutants or pollutant parameters discharged in coal pile runoff shall not exceed the limitations specified below:

| Pollutant or pollutant property | NSPS |
|---|---|
| | For any time |
| TSS ..... | not to exceed 50 mg/l. |

(12) Any untreated overflow from facilities designed, constructed, and operated to treat the coal pile runoff which results from a 10 year, 24 hour rainfall event shall not be subject to the limitations in § 423.15(a)(11).

(13) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of any mass based limitations specified in paragraphs (a)(3) through (a)(10) of this section. Concentration limits shall be based on the concentrations specified in this section.

(14) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a)(1) through (a)(13) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

(The information collection requirements contained in paragraphs (a)(8)(ii), (a)(9)(ii), and (a)(10)(ii) were approved by the Office of Management and Budget under control number 2040–0040. The information collection requirements contained in paragraph (a)(10)(iii) were approved under control number 2040–0033.)

(b) 2014 New source performance standards. Any new source as of [insert date of publication of final rule], subject

to this subpart, must achieve the following new source performance standards:

(1) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

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

(3) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum for any 1 day (mg/l) | Average of daily values for 30 consecutive days shall not exceed (mg/l) |
| TSS | 100.0 | 30.0 |
| Oil and grease | 20.0 | 15.0 |

(4) The quantity of pollutants discharged in chemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of chemical metal cleaning wastes times the concentration listed in the following table:

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum for any 1 day (mg/l) | Average of daily values for 30 consecutive days shall not exceed (mg/l) |
| TSS | 100.0 | 30.0 |
| Oil and grease | 20.0 | 15.0 |
| Copper, total | 1.0 | 1.0 |
| Iron, total | 1.0 | 1.0 |

(5) The quantity of pollutants discharged in nonchemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of nonchemical metal cleaning wastes times the concentration listed in the following table:

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum for any 1 day (mg/l) | Average of daily values for 30 consecutive days shall not exceed (mg/l) |
| TSS | 100.0 | 30.0 |
| Oil and grease | 20.0 | 15.0 |
| Copper, total | 1.0 | 1.0 |
| Iron, total | 1.0 | 1.0 |

(6) There shall be no discharge of wastewater pollutants from bottom ash transport water. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(7) There shall be no discharge of wastewater pollutants from fly ash transport water. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(8)(i) For any plant with a total rated electric generating capacity of 25 or more megawatts, the quantity of pollutants discharged in once through cooling water from each discharge point shall not exceed the quantity determined by multiplying the flow of once through cooling water from each discharge point times the concentration listed in the following table:

| Pollutant or pollutant property | NSPS |
|---|---|
| | Maximum concentration (mg/l) |
| Total residual chlorine | 0.20 |

(ii) Total residual chlorine may not be discharged from any single generating

unit for more than two hours per day unless the discharger demonstrates to the permitting authority that discharge for more than two hours is required for macroinvertebrate control.

Simultaneous multi-unit chlorination is permitted.

(9)(i) For any plant with a total rated generating capacity of less than 25 megawatts, the quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water sources times the concentration listed in the following table:

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum concentration (mg/l) | Average concentration (mg/l) |
| Free available chlorine | 0.5 | 0.2 |

(ii) Neither free available chlorine nor total residual chlorine 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 Regional Administrator or State, if the State has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(10)(i) The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown times the concentration listed below:

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum concentration (mg/l) | Average concentration (mg/l) |
| Free available chlorine | 0.5 | 0.2 |

| Pollutant or pollutant property | Maximum for any 1 day (mg/l) | Average of daily values for 30 consecutive days shall not exceed (mg/l) |
|---|---|---|
| The 126 priority pollutants (Appendix A) contained in chemicals added for cooling tower maintenance, except: | [1] | [1] |
| Chromium, total | 0.2 | 0.2 |
| Zinc, total | 1.0 | 1.0 |

[1] No detectable amount.

(ii) Neither free available chlorine nor total residual chlorine 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 Regional Administrator or State, if the State has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(iii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the limitations for the 126 priority pollutants in paragraph (b)(10)(i) of this section may be determined by engineering calculations which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136.

(11) Subject to the provisions of § 423.15(b)(12), the quantity or quality of pollutants or pollutant parameters discharged in coal pile runoff shall not exceed the limitations specified below:

| Pollutant or pollutant property | NSPS |
|---|---|
| | For any time |
| TSS | not to exceed 50 mg/l. |

(12) Any untreated overflow from facilities designed, constructed, and operated to treat the coal pile runoff which results from a 10 year, 24 hour rainfall event shall not be subject to the limitations in § 423.15(b)(11).

(13)(i) The quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the following table:

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum for any1 day (mg/l) | Average of daily values for 30 consecutive days shall not exceed |
| Arsenic, total (ug/L) | 8 | 6 |

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum for any1 day (mg/l) | Average of daily values for 30 consecutive days shall not exceed |
| Mercury, total (ng/L) | 242 | 119 |
| Selenium, tota (ug/L) | 16 | 10 |
| Nitrate/nitrite as N (mg/L) | 0.17 | 0.13 |

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(13)(i) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the FGD wastewater in any other plant process or commingling of the FGD wastewater with any water or other process wastewater, except for any combustion residual leachate or any other FGD wastewater. Compliance with the standards must reflect results obtained from sufficiently sensitive analytical methods.

(14) There shall be no discharge of wastewater pollutants from flue gas mercury control wastewater. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(15)(i) The quantity of pollutants discharged in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the following table:

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum for any 1 day | Average ff daily values for 30 consecutive days shall not exceed |
| Arsenic, total (ug/L) | 4 | (1) |
| Mercury, total (ng/L) | 1.76 | 1.29 |
| Selenium, total (ug/L) | 453 | 227 |
| Total dissolved solids (mg/L) | 38 | 22 |

[1] This regulation does not specify this type of limitation for this pollutant; however, permitting authorities may do so as appropriate.

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(15)(i) of this section, as applicable, by monitoring for all pollutants (except pH) prior to use of the gasification wastewater in any other plant process or commingling of the gasification wastewater with any water or other process wastewater. Compliance with the standards must reflect results obtained from sufficiently sensitive analytical methods.

(16)(i) The quantity of pollutants discharged in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of combustion residual leachate times the concentration listed in the following table:

| Pollutant or pollutant property | NSPS | |
|---|---|---|
| | Maximum for any 1 day | Average of daily values for 30 consecutive days shall not exceed |
| Arsenic, total (ug/L) | 8 | 6 |
| Mercury, total (ng/L) | 242 | 119 |

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(16)(i) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the combustion residual leachate in any other plant process or commingling of the combustion residual leachate with any water or other process wastewater, except for any FGD wastewater or any other combustion residual leachate. Compliance with the effluent limitations must reflect results obtained from sufficiently sensitive analytical methods.

(17) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of any mass based limitations specified in paragraphs (b)(3) through (b)(16) of this section. Concentration limits shall be based on the concentrations specified in this section.

(18) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (b)(1) through (b)(16) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

■ 7. Section 423.16 is amended by adding paragraphs (c) and (e) through (i) to read as follows:

**§ 423.16 Pretreatment standards for existing sources (PSES).**

* * * * *

(c) Except for those discharges of nonchemical metal cleaning waste that are currently authorized without meeting standards for copper, the pollutants discharged in nonchemical metal cleaning wastes shall not exceed

the concentration listed in the following table:

| Pollutant or pollutant property | PSES pretreatment standards |
|---|---|
| | Maximum for 1 day (mg/l) |
| Copper, total | 1.0 |

* * * * *

(e)(1) For any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, dischargers must meet the standards in this paragraph by a date determined by the control authority that is as soon as possible beginning July 1, 2017. These standards apply to pollutants in FGD wastewater generated on or after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Such effluent limitations shall not allow the quantity of pollutants in FGD wastewater to exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the following table:

| Pollutant or pollutant property | PSES | |
|---|---|---|
| | Maximum for any 1 day | Average of daily values for 30 consecutive days shall not exceed |
| Arsenic, total (ug/L) | 8 | 6 |
| Mercury, total (ng/L) | 242 | 119 |
| Selenium, total (ug/L) | 16 | 10 |
| Nitrate/nitrite as N (mg/L) | 0.17 | 0.13 |

(2) A discharger must demonstrate compliance with the standards in paragraph (e)(1) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the FGD wastewater in any other plant process or commingling of the FGD wastewater with any water or other process wastewater, except for any combustion residual leachate or FGD wastewater. Compliance with the effluent limitations must reflect results obtained from sufficiently sensitive analytical methods.

**Note to (e):** All proposed revisions to section 423.16(e) reflect proposed Option 4a, Option 3, and Option 3b (for units located a facilities with a total wet-scrubbed capacity of 2,000 MW or more), only. Under proposed Option 3a and Option 3b (for units located at facilities with a total wet-scrubbed capacity of less than 2,000 MW), POTWS would need to develop local limits to address the introduction of pollutants found in FGD wastewater by steam electric plants to the POTWs that cause pass through or interference, as specified in 40 CFR 403.5(c)(2).

(f) For any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, there shall be no discharge of wastewater pollutants from fly ash transport water generated on or after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(g) For any electric generating unit with a total nameplate generating capacity of more than 400 megawatts and that is not an oil-fired unit, there shall be no discharge of wastewater pollutants from bottom ash transport water generated on or after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

**Note to (g):** All proposed revisions to section 423.16(g) reflect proposed Option 4a, only. For proposed Option 3, Option 3a, and Option 3b, the regulations would not specify a PSES for bottom ash transport water.

(h) For any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, there shall be no discharge of wastewater pollutants from flue gas mercury control wastewater generated on or after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(i)(1) For any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, dischargers must meet the standards in this paragraph by a date determined by the control authority that is as soon as possible beginning July 1, 2017. These standards apply to pollutants in gasification wastewater generated on or after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Such effluent limitations shall not allow the quantity of pollutants in gasification wastewater to exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the following table:

| Pollutant or pollutant property | PSES | |
|---|---|---|
| | Maximum for any 1 day | Average of daily values for 30 consecutive days shall not exceed |
| Arsenic, total (ug/L) | 4 | (1) |
| Mercury, total (ng/L) | 1.76 | 1.29 |
| Selenium, total (ug/L) | 453 | 227 |
| Total dissolved solids (mg/L) | 38 | 22 |

[1] This regulation does not specify this type of limitation for this pollutant; however, permitting authorities may do so as appropriate.

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(2) A discharger must demonstrate compliance with the standards in paragraph (i)(1) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the gasification wastewater in any other plant process or commingling of the gasification wastewater with any water or other process wastewater. Compliance with the standards must reflect results obtained from sufficiently sensitive analytical methods.

■ 8. Section 423.17 is amended by revising paragraphs (a) and (b) to read as follows:

**§ 423.17 Pretreatment standards for new sources (PSNS).**

(a) 1982 Pretreatment standards for new sources. Except as provided in 40 CFR 403.7, any new source as of November 19, 1982, subject to this subpart, which introduces pollutants into a publicly owned treatment works must comply with 40 CFR part 403 and the following pretreatment standards for new sources (PSNS), and the revised requirements of § 423.16 of this part, published on [insert date of publication of final rule]:

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

(2) The pollutants discharged in chemical metal cleaning wastes shall not exceed the concentration listed in the following table:

| Pollutant or pollutant property | PSNS |
|---|---|
| | Maximum for any 1 day |
| Copper, total | 1.0 |

(3) [Reserved].

(4)(i) The pollutants discharged in cooling tower blowdown shall not exceed the concentration listed in the following table:

| Pollutant or pollutant property | PSNS |
|---|---|
| | Maximum for any time (mg/l) |
| The 126 priority pollutants (Appendix A) contained in chemicals added for cooling tower maintenance, except: | (1) |
| Chromium, total | 0.2 |
| Zinc, total | 1.0 |

[1] No detectable amount.

(ii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the limitations for the 126 priority pollutants in paragraph (a)(4)(i) of this section may be determined by engineering calculations which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136.

(5) There shall be no discharge of wastewater pollutants from fly ash transport water. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(b) 2014 Pretreatment standards for new sources. Except as provided in 40 CFR 403.7, any new source as of [insert date of publication of final rule], subject to this subpart, which introduces pollutants into a publicly owned treatment works must comply with 40 CFR part 403 and the following pretreatment standards for new sources (PSNS):

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

(2) The pollutants discharged in chemical metal cleaning wastes shall not exceed the concentration listed in the following table:

| Pollutant or pollutant property | PSNS |
|---|---|
| | Maximum for 1 day (mg/l) |
| Copper, total | 1.0 |

(3) The pollutants discharged in nonchemical metal cleaning wastes shall not exceed the concentration listed in the following table:

| Pollutant or pollutant property | PSNS |
|---|---|
| | Maximum for 1 day (mg/l) |
| Copper, total | 1.0 |

(4)(i) The pollutants discharged in cooling tower blowdown shall not exceed the concentration listed in the following table:

| Pollutant or pollutant property | PSNS |
|---|---|
| | Maximum for any time (mg/l) |
| The 126 priority pollutants (Appendix A) contained in chemicals added for cooling tower maintenance, except: | (1) |
| Chromium, total | 0.2 |
| Zinc, total | 1.0 |

[1] No detectable amount.

(ii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the limitations for the 126 priority pollutants in paragraph (b)(4)(i) of this section may be determined by engineering calculations which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136.

(5) There shall be no discharge of wastewater pollutants from fly ash transport water. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(6)(i) The quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the following table:

| | Pollutant or pollutant property | PSNS |
|---|---|---|
| | | Maximum for any 1 day |
| Arsenic, total (ug/L) | 8 | 6 |
| Mercury, total (ng/L) | 242 | 119 |
| Selenium, total (ug/L) | 16 | 10 |
| Nitrate/nitrite as N (mg/L) | 0.17 | 0.13 |

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(6)(i) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the FGD wastewater in any other plant process or commingling of the FGD wastewater with any water or other process wastewater, except for any combustion residual leachate or any other FGD wastewater. Compliance with the standards must reflect results obtained from sufficiently sensitive analytical methods.

(7) There shall be no discharge of wastewater pollutants from flue gas mercury control wastewater. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(8) There shall be no discharge of wastewater pollutants from bottom ash transport water. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(9)(i) The quantity of pollutants discharged in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the following table:

| Pollutant or pollutant property | PSNS |
|---|---|
| | Maximum for any 1 day |
| Arsenic, total (ug/L) | 4 |
| Mercury, total (ng/L) | 1.76 |
| Selenium, total (ug/L) | 453 |
| Total dissolved solids (mg/L) | 38 |

| | |
|---|---|
| | (1) |
| | 1.29 |
| | 227 |
| | 22 |

[1] This regulation does not specify this type of limitation for this pollutant; however, permitting authorities may do so as appropriate.

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(9)(i) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the gasification wastewater in any other plant process or commingling of the gasification wastewater with any water or other process wastewater. Compliance with the standards must reflect results obtained from sufficiently sensitive analytical methods.

(10)(i) The quantity of pollutants discharged in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of combustion residual leachate times the concentration listed in the following table:

| Pollutant or pollutant property | PSNS |
|---|---|
| | Maximum for any 1 day |
| Arsenic, total (ug/L) | 8 |
| Mercury, total (ng/L) | 242 |

| |
|---|
| 6 |
| 119 |

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(10)(i) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the combustion residual leachate in any other plant process or commingling of the combustion residual leachate with any water or other process wastewater, except for any FGD wastewater or any other combustion residual leachate. Compliance with the effluent limitations must reflect results obtained from sufficiently sensitive analytical methods.

* * * * *

[FR Doc. 2013–10191 Filed 6–6–13; 8:45 am]

BILLING CODE 6560–50–P

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**Schedule 1A**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**

| Line | | Period Amount ($) |
|---|---|---|
| 1 | End of Period Actual Total True-Up for the Period January 2014 - December 2014 (Schedule 2A, Line 5 + 6 + 9) | (3,142,723) |
| 2 | Estimated/Actual True-Up Amount approved for the period January 2014 - December 2014 (FPSC Order No. PSC-14-0643-FOF-EI) | (2,229,940) |
| 3 | Current Period True-Up Amount to be refunded/(recovered) in the projection period January 2016 - December 2016 (Lines 1 + 2) | (912,783) |

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 25
PARTY: GULF POWER COMPANY (GULF) –
(DIRECT)
DESCRIPTION: C. S. Boyett CSB-1

Schedule 2A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**

**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) | 14,427,037 | 9,814,540 | 10,171,868 | 9,839,795 | 12,280,824 | 14,558,539 | 15,631,370 | 16,134,629 | 13,508,428 | 11,125,702 | 10,398,403 | 10,527,797 | 148,418,933 |
| 2 | True-Up Provision (Order No. PSC-13-0606-FOF-EI) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,075) | (7,788,878) |
| 3 | **ECRC Revenues Applicable to Period (Lines 1 + 2)** | 13,777,964 | 9,165,467 | 9,522,795 | 9,190,722 | 11,631,751 | 13,909,466 | 14,982,297 | 15,485,556 | 12,859,355 | 10,476,629 | 9,749,330 | 9,878,722 | 140,630,055 |
| 4 | Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| | a O & M Activities (Schedule 5A, Line 9) | 3,086,570 | 2,747,697 | 2,239,814 | 1,774,143 | 2,347,923 | 1,714,073 | 3,271,590 | 2,532,730 | 1,867,003 | 2,439,332 | 1,692,133 | 2,679,685 | 28,392,693 |
| | b Capital Investment Projects (Schedule 7A, Line 9) | 9,693,176 | 9,677,372 | 9,658,895 | 9,645,777 | 9,629,014 | 9,601,653 | 9,565,150 | 9,551,708 | 9,538,634 | 9,528,466 | 9,748,775 | 9,532,429 | 115,371,046 |
| | c **Total Jurisdictional ECRC Costs** | 12,779,746 | 12,425,069 | 11,898,709 | 11,419,920 | 11,976,937 | 11,315,726 | 12,836,740 | 12,084,438 | 11,405,637 | 11,967,798 | 11,440,908 | 12,212,114 | 143,763,739 |
| 5 | **Over/(Under) Recovery (Line 3 - Line 4c)** | 998,218 | (3,259,602) | (2,375,914) | (2,229,198) | (345,185) | 2,593,740 | 2,145,558 | 3,401,118 | 1,453,719 | (1,491,168) | (1,691,578) | (2,333,392) | (3,133,684) |
| 6 | Interest Provision (Schedule 3A, Line 10) | (858) | (817) | (943) | (1,129) | (1,169) | (906) | (688) | (600) | (422) | (359) | (478) | (671) | (9,040) |
| 7 | Beginning Balance True-Up & Interest Provision | | | | | | | | | | | | | |
| | a Actual Total for True-Up Period 2013 | (10,730,771) | (9,084,337) | (11,695,683) | (13,423,467) | (15,004,721) | (14,702,002) | (11,460,095) | (8,666,153) | (4,616,561) | (2,514,191) | (3,356,645) | (4,399,628) | (10,730,771) |
| | b Final True-Up from January 2012 - December 2012 (Order No. PSC-13-0606-FOF-EI) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) |
| 8 | True-Up Collected/(Refunded) (see Line 2) | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,075 | 7,788,878 |
| 9 | Adjustments | | | | | | | | | | | | | |
| 10 | End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8 + 9) | (12,788,359) | (15,399,705) | (17,127,489) | (18,708,743) | (18,406,024) | (15,164,117) | (12,370,175) | (8,320,583) | (6,218,213) | (7,060,667) | (8,103,650) | (9,788,638) | (9,788,638) |

Schedule 3A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**

**Interest Provision**
(in Dollars)

| Line | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Beg. True-Up Amount (Schedule 2A, Lines 7a + 7b) | (14,434,792) | (12,788,359) | (15,399,705) | (17,127,489) | (18,708,743) | (18,406,024) | (15,164,117) | (12,370,175) | (8,320,583) | (6,218,213) | (7,060,667) | (8,103,650) | |
| 2 | Ending True-Up Amount Before Interest (Line 1 + Schedule 2A, Lines 5 + 8) | (12,787,501) | (15,398,888) | (17,126,546) | (18,707,614) | (18,404,855) | (15,163,211) | (12,369,486) | (8,319,983) | (6,217,792) | (7,060,309) | (8,103,172) | (9,787,967) | |
| 3 | Total of Beginning & Ending True-up (Lines 1 + 2) | (27,222,293) | (28,187,246) | (32,526,251) | (35,835,103) | (37,113,598) | (33,569,235) | (27,533,603) | (20,690,158) | (14,538,375) | (13,278,522) | (15,163,840) | (17,891,617) | |
| 4 | Average True-Up Amount (Line 3 x 1/2) | (13,611,147) | (14,093,623) | (16,263,126) | (17,917,552) | (18,556,799) | (16,784,617) | (13,766,802) | (10,345,079) | (7,269,188) | (6,639,261) | (7,581,920) | (8,945,808) | |
| 5 | Interest Rate (First Day of Reporting Business Month) | 0.000800 | 0.000700 | 0.000700 | 0.000700 | 0.000800 | 0.000700 | 0.000600 | 0.000600 | 0.000800 | 0.000600 | 0.000700 | 0.000800 | |
| 6 | Interest Rate (First Day of Subsequent Business Month) | 0.000700 | 0.000700 | 0.000700 | 0.000800 | 0.000700 | 0.000600 | 0.000600 | 0.000800 | 0.000600 | 0.000700 | 0.000800 | 0.001000 | |
| 7 | Total of Beginning and Ending Interest Rates (Line 5 + Line 6) | 0.001500 | 0.001400 | 0.001400 | 0.001500 | 0.001500 | 0.001300 | 0.001200 | 0.001400 | 0.001400 | 0.001300 | 0.001500 | 0.001800 | |
| 8 | Average Interest Rate (Line 7 x 1/2) | 0.000750 | 0.000700 | 0.000700 | 0.000750 | 0.000750 | 0.000650 | 0.000600 | 0.000700 | 0.000700 | 0.000650 | 0.000750 | 0.000900 | |
| 9 | Monthly Average Interest Rate (Line 8 x 1/12) | 0.000063 | 0.000058 | 0.000058 | 0.000063 | 0.000063 | 0.000054 | 0.000050 | 0.000058 | 0.000058 | 0.000054 | 0.000063 | 0.000075 | |
| 10 | Interest Provision for the Month (Line 4 x Line 9) | (858) | (817) | (943) | (1,129) | (1,169) | (906) | (688) | (600) | (422) | (359) | (478) | (671) | (9,040) |

**Schedule 4A**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**

**Variance Report of O & M Activities**
(in Dollars)

| Line | | (1) Final True-up | (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 | 469,310 | 474,019 | (4,709) | (1.0) | % |
| .3 | Title V | 152,482 | 152,274 | 208 | 0.1 | % |
| .4 | Asbestos Fees | (654) | 1,500 | (2,154) | (143.6) | % |
| .5 | Emission Monitoring | 639,774 | 647,122 | (7,348) | (1.1) | % |
| .6 | General Water Quality | 2,467,836 | 2,970,289 | (502,453) | (16.9) | % |
| .7 | Groundwater Contamination Investigation | 5,112,946 | 4,357,836 | 755,110 | 17.3 | % |
| .8 | State NPDES Administration | 35,194 | 49,595 | (14,401) | (29.0) | % |
| .9 | Lead and Copper Rule | 7,733 | 14,391 | (6,658) | (46.3) | % |
| .10 | Env Auditing/Assessment | 2,851 | 7,000 | (4,149) | (59.3) | % |
| .11 | General Solid & Hazardous Waste | 778,476 | 651,980 | 126,496 | 19.4 | % |
| .12 | Above Ground Storage Tanks | 98,023 | 145,928 | (47,905) | (32.8) | % |
| .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 | 20,720 | 40,094 | (19,374) | (48.3) | % |
| .17 | Gulf Coast Ozone Study | 0 | 0 | 0 | 0.0 | % |
| .18 | SPCC Substation Project | 0 | 0 | 0 | 0.0 | % |
| .19 | FDEP NOx Reduction Agreement | 1,501,938 | 2,645,183 | (1,143,245) | (43.2) | % |
| .20 | Air Quality Compliance Program | 16,295,435 | 17,026,539 | (731,104) | (4.3) | % |
| .21 | MACT ICR* | 112,491 | 0 | 112,491 | 0.0 | % |
| .22 | Crist Water Conservation | 208,910 | 218,576 | (9,666) | (4.4) | % |
| .23 | Mercury Allowances | 0 | 0 | 0 | 0.0 | % |
| .24 | Annual NOx Allowances | 632,455 | 232,319 | 400,136 | 172.2 | % |
| .25 | Seasonal NOx Allowances | 3 | 1 | 2 | 200.0 | % |
| .26 | SO2 Allowances | 656,553 | 612,359 | 44,194 | 7.2 | % |
| 2 | Total O & M Activities | 29,192,476 | 30,247,005 | (1,054,529) | (3.5) | % |
| 3 | Recoverable Costs Allocated to Energy | 20,481,161 | 21,829,910 | (1,348,749) | (6.2) | % |
| 4 | Recoverable Costs Allocated to Demand | 8,711,315 | 8,417,095 | 294,220 | 3.5 | % |

Notes:
* Line 1.21 - O&M amounts presented on Line 1.21 are related to the Air Quality Compliance Program. A 2015 entry was made to transfer the O&M amounts to the proper account.
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-14-0643-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 2014 - December 2014**

**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 | 0 | 0 | 315,444 | 0 | 0 | 1,775 | 0 | 0 | 0 | 151,339 | 0 | 751 | 469,310 | 0 | 469,310 |
| . 3 | Title V | 9,941 | 9,174 | 14,846 | 12,375 | 10,957 | 12,476 | 9,948 | 11,135 | 27,154 | 13,274 | 9,835 | 11,368 | 152,482 | 0 | 152,482 |
| . 4 | Asbestos Fees | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,035 | (2,689) | (654) | (654) | 0 |
| . 5 | Emission Monitoring | 50,359 | 60,203 | 22,298 | 51,174 | 48,912 | 53,307 | 55,104 | 59,449 | 64,760 | 57,508 | 60,269 | 56,429 | 639,774 | 0 | 639,774 |
| . 6 | General Water Quality | 92,329 | 340,463 | 304,706 | 328,337 | 238,423 | 199,683 | 327,507 | 332,535 | (33,805) | 159,224 | 112,866 | 65,568 | 2,467,836 | 2,467,836 | 0 |
| . 7 | Groundwater Contamination Investigation | 1,378,706 | 1,254,463 | 224,571 | 73,176 | 113,513 | 112,031 | 1,189,613 | 241,657 | 244,273 | 194,924 | 113,654 | (27,635) | 5,112,946 | 5,112,946 | 0 |
| . 8 | State NPDES Administration | 34,500 | 0 | 0 | 0 | 95 | 0 | 0 | 0 | 599 | 0 | 0 | 0 | 35,194 | 35,194 | 0 |
| . 9 | Lead and Copper Rule | 691 | 0 | 0 | 0 | 0 | 3,200 | 438 | 0 | 3,200 | 0 | 204 | 0 | 7,733 | 7,733 | 0 |
| . 10 | Env Auditing/Assessment | 0 | 0 | 2,000 | 0 | 241 | 0 | (2,000) | 15 | 1,334 | 926 | (49) | 383 | 2,851 | 2,851 | 0 |
| . 11 | General Solid & Hazardous Waste | 32,926 | 65,218 | 29,837 | 60,502 | 58,768 | 97,421 | 49,502 | 68,307 | 61,419 | 122,701 | 65,764 | 66,112 | 778,476 | 778,476 | 0 |
| . 12 | Above Ground Storage Tanks | (1,721) | 2,038 | (182) | (26) | 3,633 | 14,106 | 10,175 | 6,695 | 2,434 | 3,377 | 16,365 | 41,129 | 98,023 | 98,023 | 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 | 9,184 | 1,147 | 9,762 | 0 | 0 | 626 | 0 | 0 | 0 | 0 | 0 | 20,720 | 0 | 20,720 |
| . 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 | 118,618 | 117,424 | 142,828 | 81,583 | 104,644 | 106,775 | 92,083 | 109,427 | 147,367 | 168,028 | 92,613 | 220,549 | 1,501,938 | 0 | 1,501,938 |
| . 20 | Air Quality Compliance Program | 1,354,992 | 904,143 | 1,158,729 | 1,125,377 | 1,796,923 | 1,051,813 | 1,561,987 | 1,629,369 | 1,285,877 | 1,473,833 | 1,153,184 | 1,799,207 | 16,295,435 | 0 | 16,295,435 |
| . 21 | MACT ICR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5,975 | 106,516 | 112,491 | 0 | 112,491 |
| . 22 | Crist Water Conservation | (1,093) | 15,986 | 17,999 | 57,745 | (30,009) | 16,413 | (8,235) | 40,167 | 33,379 | 39,479 | 16,510 | 10,570 | 208,910 | 208,910 | 0 |
| . 23 | Mercury Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 24 | Annual NOx Allowances | 31,941 | 21,269 | 21,273 | 10,341 | 18,080 | 23,672 | 18,941 | 22,572 | 20,989 | 17,197 | 19,053 | 407,127 | 632,455 | 0 | 632,455 |
| . 25 | Seasonal NOx Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 | 0 | 3 |
| . 26 | SO2 Allowances | 76,921 | 29,620 | 49,735 | 9,024 | 46,536 | 66,982 | 55,642 | 78,740 | 57,513 | 98,620 | 74,787 | 12,434 | 656,553 | 0 | 656,553 |
| 2 | Total of O & M Activities | 3,179,108 | 2,829,186 | 2,305,231 | 1,819,371 | 2,410,716 | 1,759,653 | 3,361,332 | 2,600,068 | 1,916,494 | 2,500,430 | 1,743,068 | 2,767,819 | 29,192,476 | 8,711,315 | 20,481,161 |
| 3 | Recoverable Costs Allocated to Energy | 1,642,771 | 1,151,017 | 1,726,300 | 1,299,636 | 2,026,052 | 1,316,800 | 1,794,331 | 1,910,693 | 1,603,661 | 1,979,799 | 1,415,717 | 2,614,382 | 20,481,161 | | |
| 4 | Recoverable Costs Allocated to Demand | 1,536,336 | 1,678,168 | 578,931 | 519,735 | 384,664 | 442,853 | 1,567,001 | 689,375 | 312,833 | 520,631 | 327,351 | 153,437 | 8,711,315 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | 1,595,226 | 1,118,674 | 1,677,837 | 1,269,629 | 1,974,524 | 1,284,188 | 1,750,479 | 1,863,544 | 1,563,332 | 1,933,948 | 1,374,369 | 2,530,742 | 19,936,492 | | |
| 8 | Jurisdictional Demand Recoverable Costs (B) | 1,491,344 | 1,629,023 | 561,977 | 504,514 | 373,399 | 429,884 | 1,521,111 | 669,186 | 303,671 | 505,384 | 317,764 | 148,943 | 8,456,201 | | |
| 9 | Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8) | 3,086,570 | 2,747,697 | 2,239,814 | 1,774,143 | 2,347,923 | 1,714,073 | 3,271,590 | 2,532,730 | 1,867,003 | 2,439,332 | 1,692,133 | 2,679,685 | 28,392,693 | | |

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

**Schedule 6A**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**

**Variance Report of Capital Investment Projects - Recoverable Costs**
(in Dollars)

| Line | | (1) Final True-up | (2) Estimated/ Actual | (3) Variance Amount | (4) Variance Percent | |
|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects | | | | | |
| .1 | Air Quality Assurance Testing | 33,743 | 33,743 | 0 | 0.0 | % |
| .2 | Crist 5, 6 & 7 Precipitator Projects | 4,512,479 | 4,512,323 | 157 | 0.0 | % |
| .3 | Crist 7 Flue Gas Conditioning | 123,929 | 123,929 | 0 | 0.0 | % |
| .4 | Low NOx Burners, Crist 6 & 7 | 1,494,791 | 1,510,209 | (15,417) | (1.0) | % |
| .5 | CEMS - Plants Crist, Scholz, Smith, & Daniel | 1,053,664 | 1,053,190 | 473 | 0.0 | % |
| .6 | Sub. Contam. Mobile Groundwater Treat. Sys. | 231,405 | 231,405 | 0 | 0.0 | % |
| .7 | Raw Water Well Flowmeters - Plants Crist & Smith | 19,570 | 19,570 | 0 | 0.0 | % |
| .8 | Crist Cooling Tower Cell | 43,392 | 43,392 | 0 | 0.0 | % |
| .9 | Crist Dechlorination System | 29,716 | 29,718 | (2) | (0.0) | % |
| .10 | Crist Diesel Fuel Oil Remediation | 4,854 | 4,854 | 0 | 0.0 | % |
| .11 | Crist Bulk Tanker Unload Sec Contain Struc | 6,379 | 6,379 | 0 | 0.0 | % |
| .12 | Crist IWW Sampling System | 3,716 | 3,716 | 0 | 0.0 | % |
| .13 | Sodium Injection System | 35,084 | 35,084 | 0 | 0.0 | % |
| .14 | Smith Stormwater Collection System | 188,436 | 188,436 | 0 | 0.0 | % |
| .15 | Smith Waste Water Treatment Facility | 26,610 | 26,610 | 0 | 0.0 | % |
| .16 | Daniel Ash Management Project | 1,541,089 | 1,530,846 | 10,244 | 0.7 | % |
| .17 | Smith Water Conservation | 911,518 | 950,077 | (38,558) | (4.1) | % |
| .18 | Underground Fuel Tank Replacement | 0 | 0 | 0 | 0.0 | % |
| .19 | Crist FDEP Agreement for Ozone Attainment | 12,546,144 | 12,512,867 | 33,277 | 0.3 | % |
| .20 | SPCC Compliance | 91,028 | 91,028 | 0 | 0.0 | % |
| .21 | Crist Common FTIR Monitor | 5,629 | 5,629 | 0 | 0.0 | % |
| .22 | Precipitator Upgrades for CAM Compliance | 2,933,337 | 2,933,337 | 0 | 0.0 | % |
| .23 | Plant Groundwater Contamination | 0 | 0 | 0 | 0.0 | % |
| .24 | Crist Water Conservation | 2,128,467 | 2,127,671 | 796 | 0.0 | % |
| .25 | Plant NPDES Permit Compliance Projects | 591,845 | 591,845 | 0 | 0.0 | % |
| .26 | Air Quality Compliance Program | 89,654,317 | 89,444,055 | 210,262 | 0.2 | % |
| .27 | General Water Quality | (0) | (0) | 0 | 0.0 | % |
| .28 | Mercury Allowances | 0 | 0 | 0 | 0.0 | % |
| .29 | Annual NOx Allowances | 40,833 | 42,140 | (1,307) | (3.1) | % |
| .30 | Seasonal NOx Allowances | 0 | 0 | (0) | (5.6) | % |
| .31 | SO2 Allowances | 572,763 | 573,370 | (607) | (0.1) | % |
| 2 | Total Investment Projects - Recoverable Costs | 118,824,740 | 118,625,423 | 199,318 | 0.2 | % |
| 3 | Recoverable Costs Allocated to Energy | 9,140,364 | 9,125,033 | 15,331 | 0.2 | % |
| 4 | Recoverable Costs Allocated to Demand | 109,684,376 | 109,500,390 | 183,986 | 0.2 | % |

Notes:
Column (1) is the End of Period Totals on Schedule 7A
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-14-0643-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 2014 - December 2014**

**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 | 4,391 | 4,362 | 4,333 | 4,303 | 4,274 | 4,245 | 4,216 | 3,619 | (0) | (0) | (0) | (0) | 33,743 | 31,148 | 2,596 |
| . 2 | Crist 5, 6 & 7 Precipitator Projects | 380,720 | 379,967 | 379,213 | 378,460 | 377,707 | 376,953 | 375,174 | 374,495 | 373,517 | 372,774 | 372,082 | 371,417 | 4,512,479 | 4,165,366 | 347,114 |
| . 3 | Crist 7 Flue Gas Conditioning | 10,361 | 10,360 | 10,358 | 10,357 | 10,355 | 10,354 | 10,301 | 10,300 | 10,298 | 10,297 | 10,295 | 10,294 | 123,929 | 114,396 | 9,533 |
| . 4 | Low NOx Burners, Crist 6 & 7 | 123,049 | 122,863 | 122,678 | 122,493 | 122,308 | 122,123 | 121,459 | 123,653 | 126,012 | 126,227 | 128,458 | 133,468 | 1,494,791 | 1,379,807 | 114,984 |
| . 5 | CEMS - Plants Crist, Scholz, Smith, & Daniel | 88,740 | 88,593 | 88,445 | 88,298 | 88,151 | 88,003 | 87,527 | 87,380 | 87,233 | 87,087 | 87,374 | 86,833 | 1,053,664 | 972,613 | 81,051 |
| . 6 | Substation Contamination Remediation | 19,004 | 19,071 | 19,134 | 19,319 | 19,455 | 19,524 | 19,394 | 19,363 | 19,332 | 19,301 | 19,269 | 19,238 | 231,405 | 213,605 | 17,800 |
| . 7 | Raw Water Well Flowmeters - Plants Crist & Smith | 1,660 | 1,655 | 1,650 | 1,645 | 1,640 | 1,636 | 1,626 | 1,621 | 1,616 | 1,612 | 1,607 | 1,602 | 19,570 | 18,065 | 1,505 |
| . 8 | Crist Cooling Tower Cell | 3,631 | 3,630 | 3,629 | 3,628 | 3,626 | 3,625 | 3,607 | 3,606 | 3,604 | 3,603 | 3,602 | 3,601 | 43,392 | 40,054 | 3,338 |
| . 9 | Crist Dechlorination System | 2,501 | 2,493 | 2,485 | 2,477 | 2,470 | 2,471 | 2,477 | 2,490 | 2,479 | 2,471 | 2,455 | 2,447 | 29,716 | 27,430 | 2,286 |
| . 10 | Crist Diesel Fuel Oil Remediation | 413 | 411 | 410 | 409 | 407 | 406 | 403 | 402 | 401 | 399 | 398 | 396 | 4,854 | 4,481 | 373 |
| . 11 | Crist Bulk Tanker Unload Sec Contain Struc | 544 | 541 | 539 | 537 | 535 | 533 | 530 | 528 | 526 | 524 | 522 | 520 | 6,379 | 5,888 | 491 |
| . 12 | Crist IWW Sampling System | 317 | 315 | 314 | 313 | 312 | 311 | 309 | 307 | 306 | 305 | 304 | 303 | 3,716 | 3,430 | 286 |
| . 13 | Sodium Injection System | 2,971 | 2,963 | 2,956 | 2,948 | 2,940 | 2,932 | 2,915 | 2,907 | 2,900 | 2,892 | 2,884 | 2,876 | 35,084 | 32,385 | 2,699 |
| . 14 | Smith Stormwater Collection System | 16,017 | 15,963 | 15,910 | 15,856 | 15,803 | 15,750 | 15,656 | 15,603 | 15,550 | 15,496 | 15,443 | 15,390 | 188,436 | 173,941 | 14,495 |
| . 15 | Smith Waste Water Treatment Facility | 2,241 | 2,237 | 2,234 | 2,230 | 2,227 | 2,224 | 2,211 | 2,208 | 2,205 | 2,201 | 2,198 | 2,194 | 26,610 | 24,564 | 2,047 |
| . 16 | Daniel Ash Management Project | 129,400 | 129,094 | 128,788 | 128,482 | 128,175 | 127,869 | 127,268 | 126,963 | 126,659 | 126,354 | 135,439 | 126,598 | 1,541,089 | 1,422,544 | 118,545 |
| . 17 | Smith Water Conservation | 51,785 | 52,961 | 56,539 | 61,766 | 68,926 | 76,909 | 82,784 | 87,738 | 90,412 | 92,131 | 94,039 | 95,529 | 911,518 | 841,402 | 70,117 |
| . 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 | 1,056,956 | 1,057,028 | 1,054,574 | 1,051,946 | 1,049,235 | 1,032,751 | 1,038,379 | 1,036,822 | 1,037,342 | 1,040,558 | 1,042,703 | 1,047,847 | 12,546,144 | 11,581,056 | 965,088 |
| . 20 | SPCC Compliance | 7,702 | 7,683 | 7,664 | 7,645 | 7,626 | 7,607 | 7,564 | 7,545 | 7,526 | 7,507 | 7,488 | 7,469 | 91,028 | 84,026 | 7,002 |
| . 21 | Crist Common FTIR Monitor | 477 | 476 | 474 | 473 | 472 | 470 | 468 | 466 | 465 | 464 | 463 | 461 | 5,629 | 5,196 | 433 |
| . 22 | Precipitator Upgrades for CAM Compliance | 248,084 | 247,495 | 246,906 | 246,316 | 245,727 | 245,137 | 243,745 | 243,158 | 242,572 | 241,985 | 241,399 | 240,813 | 2,933,337 | 2,707,696 | 225,641 |
| . 23 | Plant Groundwater Investigation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 24 | Crist Water Conservation | 179,853 | 179,445 | 179,038 | 178,630 | 178,223 | 177,815 | 176,869 | 176,523 | 176,163 | 175,705 | 175,299 | 174,904 | 2,128,467 | 1,964,739 | 163,728 |
| . 25 | NPDES Permit Compliance Projects | 50,087 | 49,962 | 49,837 | 49,711 | 49,586 | 49,461 | 49,178 | 49,054 | 48,929 | 48,804 | 48,680 | 48,555 | 591,845 | 546,319 | 45,527 |
| . 26 | Air Quality Compliance Program | 7,550,367 | 7,535,312 | 7,518,148 | 7,500,894 | 7,483,831 | 7,466,744 | 7,424,781 | 7,409,040 | 7,397,274 | 7,383,281 | 7,601,962 | 7,382,683 | 89,654,317 | 82,757,831 | 6,896,486 |
| . 27 | General Water Quality | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | 0 | (0) |
| . 28 | Mercury Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 29 | Annual NOx Allowances | 4,301 | 4,116 | 3,967 | 3,857 | 3,758 | 3,612 | 3,446 | 3,302 | 3,151 | 3,018 | 2,892 | 1,413 | 40,833 | 37,692 | 3,141 |
| . 30 | Seasonal NOx Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 31 | SO2 Allowances | 49,766 | 49,394 | 49,115 | 48,908 | 48,715 | 48,318 | 47,650 | 47,184 | 46,711 | 46,169 | 45,567 | 45,265 | 572,763 | 528,704 | 44,059 |
| 2 | Total Investment Projects - Recoverable Costs | 9,985,337 | 9,968,391 | 9,949,338 | 9,931,903 | 9,916,483 | 9,887,783 | 9,849,938 | 9,836,278 | 9,823,183 | 9,811,167 | 10,042,822 | 9,822,118 | 118,824,740 | 109,684,376 | 9,140,365 |
| 3 | Recoverable Costs Allocated to Energy | 768,103 | 766,799 | 765,334 | 763,993 | 762,806 | 760,599 | 757,687 | 756,637 | 755,629 | 754,705 | 772,525 | 755,548 | 9,140,364 | | |
| 4 | Recoverable Costs Allocated to Demand | 9,217,234 | 9,201,591.36 | 9,184,004 | 9,167,910 | 9,153,677 | 9,127,184 | 9,092,250 | 9,079,641 | 9,067,554 | 9,056,461 | 9,270,298 | 9,066,570 | 109,684,376 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | 745,872 | 745,252.65 | 743,848 | 746,353 | 743,406 | 741,762 | 739,169 | 737,966 | 736,627 | 737,227 | 749,962 | 731,376 | 8,898,820 | | |
| 8 | Jurisdictional Demand Recoverable Costs (C) | 8,947,304 | 8,932,119.07 | 8,915,047 | 8,899,424 | 8,885,608 | 8,859,891 | 8,825,980 | 8,813,741 | 8,802,007 | 8,791,239 | 8,998,813 | 8,801,053 | 106,472,225 | | |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | 9,693,176 | 9,677,372 | 9,658,895 | 9,645,777 | 9,629,014 | 9,601,653 | 9,565,150 | 9,551,706 | 9,538,634 | 9,528,466 | 9,748,775 | 9,532,429 | 115,371,045 | | |

Notes:

(A) Pages 1-27 of Schedule 8E, Line 9, Pages 28-31 of Schedule 8E, Line 6
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 350,812 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 350,812 | 350,812 | 350,812 | 350,812 | 350,812 | 350,812 | 350,812 | 350,812 | 350,812 | 350,812 | 350,812 | 350,812 | 0 | |
| 3 | Less: Accumulated Depreciation (C) | (317,971) | (322,147) | (326,324) | (330,500) | (334,676) | (338,853) | (343,029) | (347,205) | (350,812) | (350,812) | (350,812) | (350,812) | (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) | 32,841 | 28,665 | 24,488 | 20,312 | 16,136 | 11,959 | 7,783 | 3,607 | (0) | (0) | (0) | (0) | (0) | |
| 6 | Average Net Investment | | 30,753 | 26,576 | 22,400 | 18,224 | 14,047 | 9,871 | 5,695 | 1,803 | (0) | (0) | (0) | (0) | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 166 | 143 | 121 | 98 | 76 | 53 | 31 | 10 | (0) | (0) | (0) | (0) | 699 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 49 | 42 | 35 | 29 | 22 | 16 | 8 | 3 | (0) | (0) | (0) | (0) | 203 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b Amortization (F) | | 4,176 | 4,176 | 4,176 | 4,176 | 4,176 | 4,176 | 4,176 | 3,607 | 0 | 0 | 0 | 0 | 32,841 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | | 4,391 | 4,362 | 4,333 | 4,303 | 4,274 | 4,245 | 4,216 | 3,619 | (0) | (0) | (0) | (0) | 33,743 |
| | a Recoverable Costs Allocated to Energy | | 338 | 336 | 333 | 331 | 329 | 327 | 324 | 278 | (0) | (0) | (0) | (0) | 2,596 |
| | b Recoverable Costs Allocated to Demand | | 4,053 | 4,026 | 3,999 | 3,972 | 3,946 | 3,919 | 3,892 | 3,341 | (0) | (0) | (0) | (0) | 31,148 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 328 | 326 | 324 | 323 | 320 | 318 | 316 | 272 | (0) | (0) | (0) | (0) | 2,528 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 3,934 | 3,908 | 3,882 | 3,856 | 3,830 | 3,804 | 3,778 | 3,243 | (0) | (0) | (0) | (0) | 30,236 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 4,262 | 4,234 | 4,206 | 4,179 | 4,150 | 4,122 | 4,094 | 3,514 | (0) | (0) | (0) | (0) | 32,764 |

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 1006 & PE 1244 are fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | | 0 | 0 | 0 | 0 | 0 | 8 | 92,148 | (71,759) | 5,849 | (3,893) | 20,302 | 4,242 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 33,557,253 | 33,557,253 | 33,557,253 | 33,557,253 | 33,557,253 | 33,557,253 | 33,557,261 | 33,557,261 | 33,557,261 | 33,557,261 | 33,557,261 | 33,557,261 | 33,557,261 | |
| 3 | Less: Accumulated Depreciation (C) | 5,588,665 | 5,480,690 | 5,372,714 | 5,264,739 | 5,156,763 | 5,048,788 | 4,940,812 | 4,832,837 | 4,724,861 | 4,616,886 | 4,508,910 | 4,400,935 | 4,292,959 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 92,148 | 20,389 | 26,238 | 22,345 | 42,647 | 46,889 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 39,145,919 | 39,037,943 | 38,929,968 | 38,821,992 | 38,714,017 | 38,606,041 | 38,498,074 | 38,482,246 | 38,302,511 | 38,200,385 | 38,088,517 | 38,000,843 | 37,897,109 | |
| 6 | Average Net Investment | | 39,091,931 | 38,983,955 | 38,875,980 | 38,768,004 | 38,660,029 | 38,552,057 | 38,490,160 | 38,392,379 | 38,251,448 | 38,144,451 | 38,044,680 | 37,948,976 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 210,940 | 210,357 | 209,775 | 209,192 | 208,610 | 208,027 | 211,773 | 211,235 | 210,459 | 209,871 | 209,322 | 208,795 | 2,518,356 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 61,804 | 61,634 | 61,463 | 61,292 | 61,122 | 60,951 | 55,426 | 55,285 | 55,082 | 54,928 | 54,784 | 54,647 | 698,417 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 97,887 | 97,887 | 97,887 | 97,887 | 97,887 | 97,887 | 97,887 | 97,887 | 97,887 | 97,887 | 97,887 | 97,887 | 1,174,638 |
| | 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 | 10,089 | 10,089 | 10,089 | 10,089 | 10,089 | 10,089 | 121,068 |
| | 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) | | 380,720 | 379,967 | 379,213 | 378,460 | 377,707 | 376,953 | 375,174 | 374,495 | 373,517 | 372,774 | 372,082 | 371,417 | 4,512,479 |
| | a Recoverable Costs Allocated to Energy | | 29,286 | 29,228 | 29,170 | 29,112 | 29,054 | 28,996 | 28,860 | 28,807 | 28,732 | 28,675 | 28,622 | 28,571 | 347,114 |
| | b Recoverable Costs Allocated to Demand | | 351,434 | 350,738 | 350,043 | 349,348 | 348,652 | 347,957 | 346,315 | 345,688 | 344,785 | 344,099 | 343,460 | 342,847 | 4,165,366 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 28,439 | 28,407 | 28,351 | 28,440 | 28,315 | 28,278 | 28,154 | 28,096 | 28,010 | 28,011 | 27,786 | 27,657 | 337,944 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 341,142 | 340,467 | 339,792 | 339,117 | 338,442 | 337,767 | 336,173 | 335,564 | 334,688 | 334,022 | 333,402 | 332,806 | 4,043,381 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 369,580 | 368,874 | 368,143 | 367,557 | 366,757 | 366,045 | 364,327 | 363,661 | 362,697 | 362,033 | 361,187 | 360,463 | 4,381,325 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | 1,454,602 | 1,454,389 | 1,454,176 | 1,453,963 | 1,453,750 | 1,453,537 | 1,453,324 | 1,453,111 | 1,452,898 | 1,452,685 | 1,452,472 | 1,452,259 | 1,452,046 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 1,454,602 | 1,454,389 | 1,454,176 | 1,453,963 | 1,453,750 | 1,453,537 | 1,453,324 | 1,453,111 | 1,452,898 | 1,452,685 | 1,452,472 | 1,452,259 | 1,452,046 | |
| 6 | Average Net Investment | | 1,454,496 | 1,454,283 | 1,454,070 | 1,453,857 | 1,453,644 | 1,453,431 | 1,453,218 | 1,453,005 | 1,452,792 | 1,452,579 | 1,452,366 | 1,452,153 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 7,848 | 7,847 | 7,846 | 7,845 | 7,844 | 7,843 | 7,996 | 7,994 | 7,993 | 7,992 | 7,991 | 7,990 | 95,030 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 2,300 | 2,299 | 2,299 | 2,299 | 2,298 | 2,298 | 2,093 | 2,092 | 2,092 | 2,092 | 2,091 | 2,091 | 26,344 |
| 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 | 213 | 213 | 213 | 213 | 213 | 213 | 2,556 |
| | 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) | | 10,361 | 10,360 | 10,358 | 10,357 | 10,355 | 10,354 | 10,301 | 10,300 | 10,298 | 10,297 | 10,295 | 10,294 | 123,929 |
| | a Recoverable Costs Allocated to Energy | | 797 | 797 | 797 | 797 | 797 | 796 | 792 | 792 | 792 | 792 | 792 | 792 | 9,533 |
| | b Recoverable Costs Allocated to Demand | | 9,564 | 9,563 | 9,561 | 9,560 | 9,559 | 9,557 | 9,509 | 9,507 | 9,506 | 9,505 | 9,503 | 9,502 | 114,396 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 774 | 774 | 774 | 778 | 776 | 777 | 773 | 773 | 772 | 774 | 769 | 767 | 9,281 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 9,284 | 9,283 | 9,281 | 9,280 | 9,279 | 9,277 | 9,230 | 9,229 | 9,228 | 9,226 | 9,225 | 9,224 | 111,046 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 10,058 | 10,057 | 10,056 | 10,058 | 10,055 | 10,054 | 10,003 | 10,002 | 10,000 | 10,000 | 9,994 | 9,990 | 120,327 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 685,059 | 47,899 | 67,126 | 628,634 | (78,832) | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,092,023 | 82,030 | |
| | c Retirements | | 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 | 34,514 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,500 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 9,097,924 | 9,097,924 | 9,097,924 | 9,097,924 | 9,097,924 | 9,097,924 | 9,097,924 | 9,097,924 | 9,097,924 | 9,097,924 | 9,097,924 | 10,189,946 | 10,271,976 | |
| 3 | Less: Accumulated Depreciation (C) | 4,747,920 | 4,721,381 | 4,694,842 | 4,668,304 | 4,641,765 | 4,615,227 | 4,588,688 | 4,562,149 | 4,535,611 | 4,509,072 | 4,482,533 | 4,455,995 | 4,458,285 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 685,059 | 732,958 | 800,084 | 336,695 | 175,834 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 13,845,843 | 13,819,305 | 13,792,766 | 13,766,227 | 13,739,689 | 13,713,150 | 13,686,611 | 13,660,073 | 14,318,593 | 14,339,954 | 14,380,541 | 14,982,636 | 14,906,094 | |
| 6 | Average Net Investment | | 13,832,574 | 13,806,035 | 13,779,497 | 13,752,958 | 13,726,419 | 13,699,881 | 13,673,342 | 13,989,333 | 14,329,273 | 14,360,247 | 14,681,588 | 14,944,365 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 74,641 | 74,497 | 74,354 | 74,211 | 74,068 | 73,925 | 75,231 | 76,969 | 78,840 | 79,010 | 80,778 | 82,224 | 918,747 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 21,869 | 21,827 | 21,785 | 21,743 | 21,701 | 21,660 | 19,690 | 20,145 | 20,634 | 20,679 | 21,141 | 21,520 | 254,395 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 26,539 | 26,539 | 26,539 | 26,539 | 26,539 | 26,539 | 26,539 | 26,539 | 26,539 | 26,539 | 26,539 | 29,724 | 321,649 |
| | 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) | | 123,049 | 122,863 | 122,678 | 122,493 | 122,308 | 122,123 | 121,459 | 123,653 | 126,012 | 126,227 | 128,458 | 133,468 | 1,494,791 |
| | a Recoverable Costs Allocated to Energy | | 9,465 | 9,451 | 9,437 | 9,423 | 9,408 | 9,394 | 9,343 | 9,512 | 9,693 | 9,710 | 9,881 | 10,267 | 114,984 |
| | b Recoverable Costs Allocated to Demand | | 113,583 | 113,412 | 113,241 | 113,070 | 112,900 | 112,729 | 112,116 | 114,141 | 116,319 | 116,518 | 118,577 | 123,201 | 1,379,807 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 9,191 | 9,185 | 9,172 | 9,205 | 9,169 | 9,161 | 9,115 | 9,277 | 9,449 | 9,485 | 9,593 | 9,938 | 111,941 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 110,257 | 110,091 | 109,925 | 109,759 | 109,593 | 109,427 | 108,833 | 110,798 | 112,913 | 113,105 | 115,104 | 119,593 | 1,339,399 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 119,448 | 119,276 | 119,097 | 118,964 | 118,762 | 118,589 | 117,947 | 120,075 | 122,362 | 122,590 | 124,697 | 129,531 | 1,451,340 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, & 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, 1440, 1441, 1442, 1444, 1445, 1454, 1459, 1460, 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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | |
| 3 | Less: Accumulated Depreciation (C) | 2,258,867 | 2,237,739 | 2,216,610 | 2,195,482 | 2,174,353 | 2,153,225 | 2,132,097 | 2,110,968 | 2,089,840 | 2,068,712 | 2,047,583 | 2,026,455 | 2,005,326 | |
| 4 | 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) | 9,537,077 | 9,515,949 | 9,494,821 | 9,473,692 | 9,452,564 | 9,431,435 | 9,410,307 | 9,389,179 | 9,368,050 | 9,346,922 | 9,325,794 | 9,304,665 | 9,283,537 | |
| 6 | Average Net Investment | | 9,526,513 | 9,505,385 | 9,484,256 | 9,463,128 | 9,442,000 | 9,420,871 | 9,399,743 | 9,378,615 | 9,357,486 | 9,336,358 | 9,315,229 | 9,294,101 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 51,405 | 51,291 | 51,177 | 51,063 | 50,949 | 50,835 | 51,717 | 51,601 | 51,485 | 51,369 | 51,252 | 51,136 | 615,281 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 15,061 | 15,028 | 14,995 | 14,961 | 14,928 | 14,894 | 13,536 | 13,505 | 13,475 | 13,444 | 13,414 | 13,384 | 170,625 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 252,392 |
| | b Amortization (F) | | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 1,149 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 1,145 | 1,145 | 1,145 | 1,145 | 1,145 | 1,145 | 1,145 | 1,145 | 1,145 | 1,145 | 1,579 | 1,185 | 14,218 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 88,740 | 88,593 | 88,445 | 88,298 | 88,151 | 88,003 | 87,527 | 87,380 | 87,233 | 87,087 | 87,374 | 86,833 | 1,053,664 |
| | a Recoverable Costs Allocated to Energy | | 6,826 | 6,815 | 6,803 | 6,792 | 6,781 | 6,769 | 6,733 | 6,722 | 6,710 | 6,699 | 6,721 | 6,679 | 81,051 |
| | b Recoverable Costs Allocated to Demand | | 81,914 | 81,778 | 81,642 | 81,506 | 81,370 | 81,234 | 80,794 | 80,659 | 80,523 | 80,388 | 80,653 | 80,153 | 972,613 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 6,629 | 6,623 | 6,612 | 6,635 | 6,608 | 6,602 | 6,568 | 6,556 | 6,542 | 6,544 | 6,525 | 6,466 | 78,910 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 79,515 | 79,383 | 79,251 | 79,119 | 78,987 | 78,855 | 78,428 | 78,296 | 78,165 | 78,034 | 78,291 | 77,806 | 944,129 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 86,144 | 86,006 | 85,863 | 85,754 | 85,595 | 85,457 | 84,996 | 84,852 | 84,706 | 84,577 | 84,816 | 84,272 | 1,023,039 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist $4,053,254; Smith $1,729,329; Daniel $584,373, Scholz $911,255.
(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) Part of PE 1283 has a 7 year amortization period. PEs 1364 & 1658 are fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | | 591 | 27,030 | (446) | 62,201 | (14,622) | (4,361) | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 591 | (20) | 0 | 0 | 90,817 | (4,361) | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 2,397,609 | 2,398,200 | 2,398,180 | 2,398,180 | 2,398,180 | 2,488,997 | 2,484,636 | 2,484,636 | 2,484,636 | 2,484,636 | 2,484,636 | 2,484,636 | 2,484,636 | |
| 3 | Less: Accumulated Depreciation (C) | (310,357) | (314,696) | (319,035) | (323,375) | (327,714) | (332,054) | (336,560) | (341,058) | (345,556) | (350,054) | (354,552) | (359,050) | (363,548) | |
| 4 | CWIP - Non Interest Bearing | 16,635 | 16,635 | 43,685 | 43,238 | 105,439 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 2,103,886 | 2,100,139 | 2,122,830 | 2,118,044 | 2,175,905 | 2,156,943 | 2,148,076 | 2,143,578 | 2,139,080 | 2,134,582 | 2,130,084 | 2,125,586 | 2,121,088 | |
| 6 | Average Net Investment | | 2,102,013 | 2,111,484 | 2,120,437 | 2,146,974 | 2,166,424 | 2,152,510 | 2,145,827 | 2,141,329 | 2,136,831 | 2,132,333 | 2,127,835 | 2,123,337 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 11,342 | 11,394 | 11,442 | 11,585 | 11,690 | 11,615 | 11,806 | 11,782 | 11,757 | 11,732 | 11,707 | 11,683 | 139,535 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 3,323 | 3,338 | 3,352 | 3,394 | 3,425 | 3,403 | 3,090 | 3,084 | 3,077 | 3,071 | 3,064 | 3,058 | 38,679 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 4,339 | 4,340 | 4,340 | 4,340 | 4,340 | 4,506 | 4,498 | 4,498 | 4,498 | 4,498 | 4,498 | 4,498 | 53,191 |
| | 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) | | 19,004 | 19,071 | 19,134 | 19,319 | 19,455 | 19,524 | 19,394 | 19,363 | 19,332 | 19,301 | 19,269 | 19,238 | 231,405 |
| | a Recoverable Costs Allocated to Energy | | 1,462 | 1,467 | 1,472 | 1,486 | 1,497 | 1,502 | 1,492 | 1,489 | 1,487 | 1,485 | 1,482 | 1,480 | 17,800 |
| | b Recoverable Costs Allocated to Demand | | 17,542 | 17,604 | 17,662 | 17,833 | 17,958 | 18,022 | 17,902 | 17,874 | 17,845 | 17,816 | 17,787 | 17,758 | 213,605 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,420 | 1,426 | 1,431 | 1,452 | 1,458 | 1,465 | 1,455 | 1,453 | 1,450 | 1,450 | 1,439 | 1,433 | 17,330 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 17,029 | 17,089 | 17,145 | 17,311 | 17,432 | 17,494 | 17,378 | 17,350 | 17,322 | 17,294 | 17,266 | 17,238 | 207,349 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 18,448 | 18,515 | 18,575 | 18,762 | 18,891 | 18,959 | 18,834 | 18,803 | 18,772 | 18,745 | 18,705 | 18,671 | 224,679 |

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) The amortizable portion of 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | 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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | |
| 3 | Less: Accumulated Depreciation (C) | (104,094) | (104,787) | (105,481) | (106,174) | (106,867) | (107,560) | (108,253) | (108,947) | (109,640) | (110,333) | (111,026) | (111,719) | (112,413) | |
| 4 | 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) | 138,878 | 138,185 | 137,492 | 136,799 | 136,106 | 135,412 | 134,719 | 134,026 | 133,333 | 132,640 | 131,946 | 131,253 | 130,560 | |
| 6 | Average Net Investment | | 138,532 | 137,839 | 137,145 | 136,452 | 135,759 | 135,066 | 134,373 | 133,679 | 132,986 | 132,293 | 131,600 | 130,906 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 748 | 744 | 740 | 736 | 733 | 729 | 739 | 736 | 732 | 728 | 724 | 720 | 8,808 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 219 | 218 | 217 | 216 | 215 | 214 | 193 | 192 | 192 | 191 | 190 | 189 | 2,444 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 8,319 |
| | 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) | | 1,660 | 1,655 | 1,650 | 1,645 | 1,640 | 1,636 | 1,626 | 1,621 | 1,616 | 1,612 | 1,607 | 1,602 | 19,570 |
| | a Recoverable Costs Allocated to Energy | | 128 | 127 | 127 | 127 | 126 | 126 | 125 | 125 | 124 | 124 | 124 | 123 | 1,505 |
| | b Recoverable Costs Allocated to Demand | | 1,532 | 1,528 | 1,523 | 1,519 | 1,514 | 1,510 | 1,501 | 1,497 | 1,492 | 1,488 | 1,483 | 1,479 | 18,065 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 124 | 124 | 123 | 124 | 123 | 123 | 122 | 122 | 121 | 121 | 120 | 119 | 1,466 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 1,487 | 1,483 | 1,479 | 1,474 | 1,470 | 1,466 | 1,457 | 1,453 | 1,448 | 1,444 | 1,440 | 1,435 | 17,535 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,611 | 1,607 | 1,602 | 1,598 | 1,593 | 1,588 | 1,579 | 1,574 | 1,570 | 1,565 | 1,560 | 1,555 | 19,001 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist $149,950; Smith $93,023.
(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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | 496,311 | 496,142 | 495,973 | 495,804 | 495,635 | 495,466 | 495,297 | 495,128 | 494,959 | 494,790 | 494,621 | 494,452 | 494,283 | |
| 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) | 496,311 | 496,142 | 495,973 | 495,804 | 495,635 | 495,466 | 495,297 | 495,128 | 494,959 | 494,790 | 494,621 | 494,452 | 494,283 | |
| 6 | Average Net Investment | | 496,227 | 496,058 | 495,889 | 495,720 | 495,551 | 495,382 | 495,213 | 495,044 | 494,875 | 494,706 | 494,537 | 494,368 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 2,678 | 2,677 | 2,676 | 2,675 | 2,674 | 2,673 | 2,725 | 2,724 | 2,723 | 2,722 | 2,721 | 2,720 | 32,386 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 785 | 784 | 784 | 784 | 783 | 783 | 713 | 713 | 713 | 712 | 712 | 712 | 8,978 |
| 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 | 169 | 169 | 169 | 169 | 169 | 169 | 2,028 |
| | 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) | | 3,631 | 3,630 | 3,629 | 3,628 | 3,626 | 3,625 | 3,607 | 3,606 | 3,604 | 3,603 | 3,602 | 3,601 | 43,392 |
| | a Recoverable Costs Allocated to Energy | | 279 | 279 | 279 | 279 | 279 | 279 | 277 | 277 | 277 | 277 | 277 | 277 | 3,338 |
| | b Recoverable Costs Allocated to Demand | | 3,352 | 3,351 | 3,350 | 3,349 | 3,348 | 3,346 | 3,329 | 3,328 | 3,327 | 3,326 | 3,325 | 3,324 | 40,054 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 271 | 271 | 271 | 273 | 272 | 272 | 271 | 271 | 270 | 271 | 269 | 268 | 3,250 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 3,254 | 3,253 | 3,252 | 3,251 | 3,249 | 3,248 | 3,232 | 3,231 | 3,230 | 3,229 | 3,228 | 3,227 | 38,881 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 3,525 | 3,524 | 3,523 | 3,523 | 3,521 | 3,520 | 3,502 | 3,501 | 3,500 | 3,499 | 3,497 | 3,495 | 42,131 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | 2,585 | 3,270 | (203) | 26 | (29) | (2) | (2) | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 2,920 | 2,731 | 26 | (29) | (2) | (2) | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4,075 | 0 | 2,757 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 227 | 176 | 2 | (2) | 0 | (0) | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 381,885 | 381,885 | 381,885 | 381,885 | 381,885 | 381,885 | 381,885 | 384,805 | 383,461 | 383,487 | 380,701 | 380,699 | 380,697 | |
| 3 | Less: Accumulated Depreciation (C) | (182,570) | (183,684) | (184,798) | (185,912) | (187,025) | (188,139) | (189,253) | (190,140) | (187,012) | (188,129) | (186,493) | (187,603) | (188,714) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 2,585 | 2,935 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 199,315 | 198,201 | 197,087 | 195,973 | 194,859 | 193,746 | 195,217 | 197,600 | 196,450 | 195,358 | 194,208 | 193,096 | 191,983 | |
| 6 | Average Net Investment | | 198,758 | 197,644 | 196,530 | 195,416 | 194,303 | 194,481 | 196,408 | 197,025 | 195,904 | 194,783 | 193,652 | 192,539 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 1,073 | 1,066 | 1,060 | 1,054 | 1,048 | 1,049 | 1,081 | 1,084 | 1,078 | 1,072 | 1,065 | 1,059 | 12,791 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 314 | 312 | 311 | 309 | 307 | 307 | 283 | 284 | 282 | 280 | 279 | 277 | 3,546 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 1,114 | 1,114 | 1,114 | 1,114 | 1,114 | 1,114 | 1,114 | 1,122 | 1,119 | 1,119 | 1,111 | 1,111 | 13,378 |
| | 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) | | 2,501 | 2,493 | 2,485 | 2,477 | 2,470 | 2,471 | 2,477 | 2,490 | 2,479 | 2,471 | 2,455 | 2,447 | 29,716 |
| | a Recoverable Costs Allocated to Energy | | 192 | 192 | 191 | 191 | 190 | 190 | 191 | 192 | 191 | 190 | 189 | 188 | 2,286 |
| | b Recoverable Costs Allocated to Demand | | 2,308 | 2,301 | 2,294 | 2,287 | 2,280 | 2,281 | 2,287 | 2,299 | 2,288 | 2,281 | 2,266 | 2,259 | 27,430 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 187 | 186 | 186 | 186 | 185 | 185 | 186 | 187 | 186 | 186 | 183 | 182 | 2,225 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,241 | 2,234 | 2,227 | 2,220 | 2,213 | 2,214 | 2,220 | 2,231 | 2,221 | 2,214 | 2,200 | 2,193 | 26,626 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,428 | 2,420 | 2,413 | 2,406 | 2,398 | 2,399 | 2,406 | 2,418 | 2,407 | 2,400 | 2,383 | 2,375 | 28,852 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (38,480) | (38,681) | (38,882) | (39,084) | (39,285) | (39,486) | (39,687) | (39,888) | (40,089) | (40,290) | (40,491) | (40,692) | (40,893) | |
| 4 | 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) | 30,443 | 30,242 | 30,041 | 29,840 | 29,638 | 29,437 | 29,236 | 29,035 | 28,834 | 28,633 | 28,432 | 28,231 | 28,030 | |
| 6 | Average Net Investment | | 30,342 | 30,141 | 29,940 | 29,739 | 29,538 | 29,337 | 29,136 | 28,935 | 28,734 | 28,533 | 28,332 | 28,131 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 164 | 163 | 162 | 160 | 159 | 158 | 160 | 159 | 158 | 157 | 156 | 155 | 1,911 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 48 | 48 | 47 | 47 | 47 | 46 | 42 | 42 | 41 | 41 | 41 | 41 | 530 |
| 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) | | 413 | 411 | 410 | 409 | 407 | 406 | 403 | 402 | 401 | 399 | 398 | 396 | 4,854 |
| | a Recoverable Costs Allocated to Energy | | 32 | 32 | 32 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 30 | 373 |
| | b Recoverable Costs Allocated to Demand | | 381 | 380 | 378 | 377 | 376 | 375 | 372 | 371 | 370 | 368 | 367 | 366 | 4,481 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 31 | 31 | 31 | 31 | 31 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 364 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 370 | 369 | 367 | 366 | 365 | 364 | 361 | 360 | 359 | 358 | 356 | 355 | 4,350 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 401 | 399 | 398 | 397 | 395 | 394 | 392 | 390 | 389 | 388 | 386 | 385 | 4,713 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (65,878) | (66,175) | (66,471) | (66,767) | (67,063) | (67,359) | (67,655) | (67,951) | (68,247) | (68,543) | (68,839) | (69,135) | (69,431) | |
| 4 | 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) | 35,617 | 35,321 | 35,024 | 34,728 | 34,432 | 34,136 | 33,840 | 33,544 | 33,248 | 32,952 | 32,656 | 32,360 | 32,064 | |
| 6 | Average Net Investment | | 35,469 | 35,173 | 34,876 | 34,580 | 34,284 | 33,988 | 33,692 | 33,396 | 33,100 | 32,804 | 32,508 | 32,212 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 191 | 190 | 188 | 187 | 185 | 183 | 185 | 184 | 182 | 180 | 179 | 177 | 2,212 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 56 | 56 | 55 | 55 | 54 | 54 | 49 | 48 | 48 | 47 | 47 | 46 | 614 |
| 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) | | 544 | 541 | 539 | 537 | 535 | 533 | 530 | 528 | 526 | 524 | 522 | 520 | 6,379 |
| | a Recoverable Costs Allocated to Energy | | 42 | 42 | 41 | 41 | 41 | 41 | 41 | 41 | 40 | 40 | 40 | 40 | 491 |
| | b Recoverable Costs Allocated to Demand | | 502 | 500 | 498 | 496 | 494 | 492 | 489 | 487 | 485 | 483 | 482 | 480 | 5,888 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 41 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 39 | 39 | 39 | 39 | 478 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 487 | 485 | 483 | 481 | 480 | 478 | 475 | 473 | 471 | 469 | 467 | 466 | 5,716 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 528 | 526 | 524 | 522 | 520 | 518 | 515 | 513 | 511 | 509 | 506 | 504 | 6,194 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (38,966) | (39,140) | (39,314) | (39,487) | (39,661) | (39,835) | (40,008) | (40,182) | (40,356) | (40,529) | (40,703) | (40,877) | (41,051) | |
| 4 | 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) | 20,577 | 20,403 | 20,229 | 20,055 | 19,882 | 19,708 | 19,534 | 19,361 | 19,187 | 19,013 | 18,840 | 18,666 | 18,492 | |
| 6 | Average Net Investment | | 20,490 | 20,316 | 20,142 | 19,969 | 19,795 | 19,621 | 19,448 | 19,274 | 19,100 | 18,926 | 18,753 | 18,579 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 111 | 110 | 109 | 108 | 107 | 106 | 107 | 106 | 105 | 104 | 103 | 102 | 1,277 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 32 | 32 | 32 | 32 | 31 | 31 | 28 | 28 | 28 | 27 | 27 | 27 | 355 |
| 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) | | 317 | 315 | 314 | 313 | 312 | 311 | 309 | 307 | 306 | 305 | 304 | 303 | 3,716 |
| | a Recoverable Costs Allocated to Energy | | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 23 | 23 | 23 | 286 |
| | b Recoverable Costs Allocated to Demand | | 292 | 291 | 290 | 289 | 288 | 287 | 285 | 284 | 283 | 282 | 281 | 279 | 3,430 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 24 | 24 | 23 | 24 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 278 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 284 | 283 | 282 | 280 | 279 | 278 | 277 | 276 | 274 | 273 | 272 | 271 | 3,330 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 307 | 306 | 305 | 304 | 303 | 302 | 300 | 299 | 297 | 296 | 295 | 294 | 3,608 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E.s 1214 & 1413
(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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | |
| 3 | Less: Accumulated Depreciation (C) | (125,671) | (126,794) | (127,918) | (129,041) | (130,164) | (131,287) | (132,410) | (133,533) | (134,656) | (135,779) | (136,902) | (138,026) | (139,149) | |
| 4 | 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) | 265,448 | 264,325 | 263,201 | 262,078 | 260,955 | 259,832 | 258,709 | 257,586 | 256,463 | 255,340 | 254,217 | 253,093 | 251,970 | |
| 6 | Average Net Investment | | 264,886 | 263,763 | 262,640 | 261,517 | 260,394 | 259,271 | 258,147 | 257,024 | 255,901 | 254,778 | 253,655 | 252,532 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 1,429 | 1,423 | 1,417 | 1,411 | 1,405 | 1,399 | 1,420 | 1,414 | 1,408 | 1,402 | 1,396 | 1,389 | 16,914 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 419 | 417 | 415 | 413 | 412 | 410 | 372 | 370 | 368 | 367 | 365 | 364 | 4,692 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 13,477 |
| | 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) | | 2,971 | 2,963 | 2,956 | 2,948 | 2,940 | 2,932 | 2,915 | 2,907 | 2,900 | 2,892 | 2,884 | 2,876 | 35,084 |
| | a Recoverable Costs Allocated to Energy | | 229 | 228 | 227 | 227 | 226 | 226 | 224 | 224 | 223 | 222 | 222 | 221 | 2,699 |
| | b Recoverable Costs Allocated to Demand | | 2,743 | 2,735 | 2,728 | 2,721 | 2,714 | 2,706 | 2,691 | 2,684 | 2,677 | 2,669 | 2,662 | 2,655 | 32,385 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 222 | 222 | 221 | 222 | 220 | 220 | 219 | 218 | 217 | 217 | 215 | 214 | 2,627 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,662 | 2,655 | 2,648 | 2,641 | 2,634 | 2,627 | 2,612 | 2,605 | 2,598 | 2,591 | 2,584 | 2,577 | 31,437 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,884 | 2,877 | 2,869 | 2,863 | 2,855 | 2,847 | 2,831 | 2,823 | 2,816 | 2,808 | 2,800 | 2,791 | 34,064 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist $284,622; Smith $106,497.
(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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | |
| 3 | Less: Accumulated Depreciation (C) | (1,579,928) | (1,587,580) | (1,595,232) | (1,602,884) | (1,610,536) | (1,618,189) | (1,625,841) | (1,633,493) | (1,641,145) | (1,648,797) | (1,656,449) | (1,664,102) | (1,671,754) | |
| 4 | 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) | 1,202,672 | 1,195,020 | 1,187,368 | 1,179,716 | 1,172,064 | 1,164,412 | 1,156,759 | 1,149,107 | 1,141,455 | 1,133,803 | 1,126,151 | 1,118,499 | 1,110,847 | |
| 6 | Average Net Investment | | 1,198,846 | 1,191,194 | 1,183,542 | 1,175,890 | 1,168,238 | 1,160,586 | 1,152,933 | 1,145,281 | 1,137,629 | 1,129,977 | 1,122,325 | 1,114,673 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 6,469 | 6,428 | 6,386 | 6,345 | 6,304 | 6,263 | 6,343 | 6,301 | 6,259 | 6,217 | 6,175 | 6,133 | 75,624 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,895 | 1,883 | 1,871 | 1,859 | 1,847 | 1,835 | 1,660 | 1,649 | 1,638 | 1,627 | 1,616 | 1,605 | 20,987 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 91,826 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 16,017 | 15,963 | 15,910 | 15,856 | 15,803 | 15,750 | 15,656 | 15,603 | 15,550 | 15,496 | 15,443 | 15,390 | 188,436 |
| | a Recoverable Costs Allocated to Energy | | 1,232 | 1,228 | 1,224 | 1,220 | 1,216 | 1,212 | 1,204 | 1,200 | 1,196 | 1,192 | 1,188 | 1,184 | 14,495 |
| | b Recoverable Costs Allocated to Demand | | 14,784 | 14,735 | 14,686 | 14,637 | 14,587 | 14,538 | 14,452 | 14,402 | 14,353 | 14,304 | 14,255 | 14,206 | 173,941 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,196 | 1,193 | 1,189 | 1,192 | 1,185 | 1,182 | 1,175 | 1,171 | 1,166 | 1,164 | 1,153 | 1,146 | 14,112 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 14,351 | 14,304 | 14,256 | 14,208 | 14,160 | 14,112 | 14,028 | 13,981 | 13,933 | 13,886 | 13,838 | 13,790 | 168,847 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 15,548 | 15,497 | 15,445 | 15,400 | 15,345 | 15,294 | 15,203 | 15,151 | 15,099 | 15,050 | 14,991 | 14,936 | 182,959 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | 71,906 | 71,414 | 70,922 | 70,430 | 69,938 | 69,445 | 68,953 | 68,461 | 67,969 | 67,477 | 66,985 | 66,492 | 66,000 | |
| 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) (A) | 250,868 | 250,376 | 249,884 | 249,392 | 248,899 | 248,407 | 247,915 | 247,423 | 246,931 | 246,439 | 245,947 | 245,454 | 244,962 | |
| 6 | Average Net Investment | | 250,622 | 250,130 | 249,638 | 249,146 | 248,653 | 248,161 | 247,669 | 247,177 | 246,685 | 246,193 | 245,700 | 245,208 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 1,352 | 1,350 | 1,347 | 1,344 | 1,342 | 1,339 | 1,363 | 1,360 | 1,357 | 1,355 | 1,352 | 1,349 | 16,210 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 396 | 395 | 395 | 394 | 393 | 392 | 357 | 356 | 355 | 355 | 354 | 353 | 4,495 |
| 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) | | 2,241 | 2,237 | 2,234 | 2,230 | 2,227 | 2,224 | 2,211 | 2,208 | 2,205 | 2,201 | 2,198 | 2,194 | 26,610 |
| | a Recoverable Costs Allocated to Energy | | 172 | 172 | 172 | 172 | 171 | 171 | 170 | 170 | 170 | 169 | 169 | 169 | 2,047 |
| | b Recoverable Costs Allocated to Demand | | 2,068 | 2,065 | 2,062 | 2,059 | 2,056 | 2,053 | 2,041 | 2,038 | 2,035 | 2,032 | 2,029 | 2,026 | 24,564 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 167 | 167 | 167 | 168 | 167 | 167 | 166 | 166 | 165 | 165 | 164 | 163 | 1,993 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,008 | 2,005 | 2,002 | 1,999 | 1,995 | 1,992 | 1,982 | 1,979 | 1,975 | 1,972 | 1,969 | 1,966 | 23,844 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,175 | 2,172 | 2,169 | 2,166 | 2,162 | 2,159 | 2,148 | 2,144 | 2,141 | 2,138 | 2,133 | 2,130 | 25,837 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (6,221,798) | (6,265,673) | (6,309,548) | (6,353,422) | (6,397,297) | (6,441,171) | (6,485,046) | (6,528,921) | (6,572,795) | (6,616,670) | (6,660,545) | (6,704,419) | (6,748,294) | |
| 4 | 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) | 8,728,326 | 8,684,451 | 8,640,576 | 8,596,702 | 8,552,827 | 8,508,953 | 8,465,078 | 8,421,203 | 8,377,329 | 8,333,454 | 8,289,579 | 8,245,705 | 8,201,830 | |
| 6 | Average Net Investment | | 8,706,388 | 8,662,514 | 8,618,639 | 8,574,765 | 8,530,890 | 8,487,015 | 8,443,141 | 8,399,266 | 8,355,391 | 8,311,517 | 8,267,642 | 8,223,767 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 46,980 | 46,743 | 46,506 | 46,269 | 46,033 | 45,796 | 46,454 | 46,213 | 45,971 | 45,730 | 45,489 | 45,247 | 553,431 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 13,765 | 13,695 | 13,626 | 13,557 | 13,487 | 13,418 | 12,158 | 12,095 | 12,032 | 11,969 | 11,905 | 11,842 | 153,549 |
| 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 | 8,996 | 8,996 | 8,996 | 8,996 | 8,996 | 8,996 | 107,952 |
| | d Property Taxes | | 24,781 | 24,781 | 24,781 | 24,781 | 24,781 | 24,781 | 24,781 | 24,781 | 24,781 | 24,781 | 34,171 | 25,634 | 307,613 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 129,400 | 129,094 | 128,788 | 128,482 | 128,175 | 127,869 | 127,268 | 126,963 | 126,659 | 126,354 | 135,439 | 126,598 | 1,541,089 |
| | a Recoverable Costs Allocated to Energy | | 9,954 | 9,930 | 9,907 | 9,883 | 9,860 | 9,836 | 9,790 | 9,766 | 9,743 | 9,720 | 10,418 | 9,738 | 118,545 |
| | b Recoverable Costs Allocated to Demand | | 119,446 | 119,164 | 118,881 | 118,598 | 118,316 | 118,033 | 117,478 | 117,197 | 116,916 | 116,634 | 125,021 | 116,860 | 1,422,544 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 9,666 | 9,651 | 9,629 | 9,655 | 9,609 | 9,593 | 9,551 | 9,525 | 9,498 | 9,494 | 10,114 | 9,427 | 115,411 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 115,948 | 115,674 | 115,399 | 115,125 | 114,851 | 114,577 | 114,038 | 113,765 | 113,492 | 113,219 | 121,360 | 113,438 | 1,380,884 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 125,614 | 125,325 | 125,028 | 124,780 | 124,460 | 124,169 | 123,588 | 123,290 | 122,990 | 122,713 | 131,474 | 122,865 | 1,496,295 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E.s 1601, 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 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 57,653 | 279,930 | 746,587 | 752,503 | 1,300,631 | 988,478 | 815,472 | 612,723 | 158,373 | 337,438 | 212,988 | 217,131 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | |
| 3 | Less: Accumulated Depreciation (C) | (39,626) | (39,995) | (40,364) | (40,733) | (41,101) | (41,470) | (41,839) | (42,208) | (42,577) | (42,946) | (43,315) | (43,683) | (44,052) | |
| 4 | CWIP - Non Interest Bearing | 7,246,289 | 7,303,942 | 7,583,872 | 8,330,459 | 9,082,962 | 10,383,593 | 11,372,071 | 12,187,543 | 12,800,266 | 12,958,639 | 13,296,077 | 13,509,065 | 13,726,196 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 7,340,798 | 7,398,082 | 7,677,643 | 8,423,861 | 9,175,995 | 10,476,257 | 11,464,367 | 12,279,469 | 12,891,823 | 13,049,827 | 13,386,897 | 13,599,516 | 13,816,278 | |
| 6 | Average Net Investment | | 7,369,440 | 7,537,862 | 8,050,752 | 8,799,928 | 9,826,126 | 10,970,312 | 11,871,918 | 12,585,646 | 12,970,825 | 13,218,362 | 13,493,206 | 13,707,897 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 39,765 | 40,674 | 43,442 | 47,484 | 53,022 | 59,196 | 65,319 | 69,246 | 71,365 | 72,727 | 74,240 | 75,421 | 711,903 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 11,651 | 11,917 | 12,728 | 13,913 | 15,535 | 17,344 | 17,096 | 18,123 | 18,678 | 19,034 | 19,430 | 19,739 | 195,189 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 4,426 |
| | 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) | | 51,785 | 52,961 | 56,539 | 61,766 | 68,926 | 76,909 | 82,784 | 87,738 | 90,412 | 92,131 | 94,039 | 95,529 | 911,518 |
| | a Recoverable Costs Allocated to Energy | | 3,983 | 4,074 | 4,349 | 4,751 | 5,302 | 5,916 | 6,368 | 6,749 | 6,955 | 7,087 | 7,234 | 7,348 | 70,117 |
| | b Recoverable Costs Allocated to Demand | | 47,802 | 48,887 | 52,190 | 57,015 | 63,624 | 70,993 | 76,416 | 80,989 | 83,458 | 85,044 | 86,805 | 88,181 | 841,402 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 3,868 | 3,959 | 4,227 | 4,642 | 5,167 | 5,770 | 6,212 | 6,583 | 6,780 | 6,923 | 7,022 | 7,113 | 68,266 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 46,402 | 47,455 | 50,661 | 55,345 | 61,761 | 68,914 | 74,178 | 78,618 | 81,013 | 82,553 | 84,263 | 85,598 | 816,761 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 50,270 | 51,414 | 54,888 | 59,987 | 66,928 | 74,683 | 80,390 | 85,200 | 87,793 | 89,476 | 91,285 | 92,712 | 885,027 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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 | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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
(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 | | 736,784 | 41,723 | 12,632 | (7,983) | (11,232) | (1) | (1,719) | 306,515 | 434,566 | 1,054,340 | 288,355 | 139,041 | |
| | b Clearings to Plant | | 0 | 433 | 7,176 | 5,977 | 561 | (6,142) | (1) | (2) | 1 | 2 | 2,785,806 | 194,441 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 192,506 | 0 | 0 | 0 | 0 | 0 | 1,552,008 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 169,174 | 1,664 | (161) | 17,344 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 7,203 | (27,257) | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 117,949,228 | 117,949,228 | 117,949,661 | 117,956,837 | 117,962,814 | 117,963,375 | 117,764,727 | 117,764,726 | 117,764,724 | 117,764,725 | 117,764,727 | 120,550,533 | 119,192,966 | |
| 3 | Less: Accumulated Depreciation (C) | (20,950,179) | (21,329,125) | (21,708,070) | (22,087,016) | (22,465,962) | (22,844,908) | (23,017,498) | (23,394,152) | (23,770,806) | (23,985,490) | (24,333,223) | (24,710,038) | (23,523,577) | |
| 4 | CWIP - Non Interest Bearing | (0) | 736,784 | 778,073 | 783,529 | 769,569 | 757,776 | 763,917 | 762,199 | 1,068,717 | 1,503,281 | 2,557,619 | 60,169 | 4,769 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 96,999,049 | 97,356,887 | 97,019,664 | 96,653,350 | 96,266,421 | 95,876,244 | 95,511,146 | 95,132,773 | 95,062,634 | 95,282,516 | 95,989,123 | 95,900,664 | 95,674,158 | |
| 6 | Average Net Investment | | 97,177,968 | 97,188,275 | 96,836,507 | 96,459,885 | 96,071,332 | 95,693,695 | 95,321,959 | 95,097,704 | 95,172,575 | 95,635,819 | 95,944,893 | 95,787,411 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 524,372 | 524,428 | 522,530 | 520,498 | 518,401 | 516,363 | 524,461 | 523,228 | 523,640 | 526,188 | 527,889 | 527,022 | 6,279,020 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 153,638 | 153,655 | 153,099 | 152,503 | 151,889 | 151,292 | 137,264 | 136,941 | 137,049 | 137,716 | 138,161 | 137,934 | 1,741,138 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 343,338 | 343,338 | 343,338 | 343,338 | 343,338 | 343,338 | 343,338 | 343,338 | 343,338 | 343,338 | 343,338 | 349,575 | 4,126,295 |
| | b Amortization (F) | | 2,938 | 2,938 | 2,938 | 2,938 | 2,938 | (10,912) | 646 | 646 | 646 | 646 | 646 | 646 | 7,651 |
| | c Dismantlement | | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 392,040 |
| | 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) | | 1,056,956 | 1,057,028 | 1,054,574 | 1,051,946 | 1,049,235 | 1,032,751 | 1,038,379 | 1,036,822 | 1,037,342 | 1,040,558 | 1,042,703 | 1,047,847 | 12,546,144 |
| | a Recoverable Costs Allocated to Energy | | 81,304 | 81,310 | 81,121 | 80,919 | 80,710 | 79,442 | 79,875 | 79,756 | 79,796 | 80,043 | 80,208 | 80,604 | 965,088 |
| | b Recoverable Costs Allocated to Demand | | 975,652 | 975,719 | 973,453 | 971,027 | 968,525 | 953,309 | 958,504 | 957,067 | 957,547 | 960,515 | 962,496 | 967,243 | 11,581,056 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 78,951 | 79,025 | 78,844 | 79,051 | 78,658 | 77,475 | 77,923 | 77,787 | 77,789 | 78,189 | 77,865 | 78,025 | 939,582 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 947,080 | 947,144 | 944,945 | 942,591 | 940,161 | 925,391 | 930,434 | 929,039 | 929,504 | 932,386 | 934,308 | 938,917 | 11,241,900 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,026,031 | 1,026,169 | 1,023,789 | 1,021,641 | 1,018,819 | 1,002,866 | 1,008,357 | 1,006,826 | 1,007,293 | 1,010,575 | 1,012,174 | 1,016,942 | 12,181,482 |

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 1158 have a 7-year amortization period. The amortizable portion of 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.s 1272, 1404, & 1628
(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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | |
| 3 | Less: Accumulated Depreciation (C) | (219,862) | (222,586) | (225,311) | (228,035) | (230,759) | (233,483) | (236,207) | (238,931) | (241,655) | (244,379) | (247,103) | (249,828) | (252,552) | |
| 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) (A) | 714,868 | 712,144 | 709,420 | 706,696 | 703,971 | 701,247 | 698,523 | 695,799 | 693,075 | 690,351 | 687,627 | 684,903 | 682,178 | |
| 6 | Average Net Investment | | 713,506 | 710,782 | 708,058 | 705,333 | 702,609 | 699,885 | 697,161 | 694,437 | 691,713 | 688,989 | 686,265 | 683,541 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 3,850 | 3,835 | 3,821 | 3,806 | 3,791 | 3,777 | 3,836 | 3,821 | 3,806 | 3,791 | 3,776 | 3,761 | 45,670 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,128 | 1,124 | 1,119 | 1,115 | 1,111 | 1,107 | 1,004 | 1,000 | 996 | 992 | 988 | 984 | 12,668 |
| 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) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | | 7,702 | 7,683 | 7,664 | 7,645 | 7,626 | 7,607 | 7,564 | 7,545 | 7,526 | 7,507 | 7,488 | 7,469 | 91,028 |
| | a Recoverable Costs Allocated to Energy | | 592 | 591 | 590 | 588 | 587 | 585 | 582 | 580 | 579 | 577 | 576 | 575 | 7,002 |
| | b Recoverable Costs Allocated to Demand | | 7,110 | 7,092 | 7,075 | 7,057 | 7,040 | 7,022 | 6,982 | 6,965 | 6,947 | 6,930 | 6,912 | 6,895 | 84,026 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 575 | 574 | 573 | 575 | 572 | 571 | 568 | 566 | 564 | 564 | 559 | 556 | 6,817 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 6,902 | 6,885 | 6,867 | 6,850 | 6,833 | 6,816 | 6,778 | 6,761 | 6,744 | 6,727 | 6,710 | 6,693 | 81,565 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 7,477 | 7,459 | 7,441 | 7,425 | 7,405 | 7,387 | 7,345 | 7,327 | 7,308 | 7,291 | 7,269 | 7,249 | 88,382 |

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) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (20,722) | (20,905) | (21,089) | (21,272) | (21,456) | (21,639) | (21,822) | (22,006) | (22,189) | (22,373) | (22,556) | (22,739) | (22,923) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 42,148 | 41,965 | 41,782 | 41,598 | 41,415 | 41,231 | 41,048 | 40,865 | 40,681 | 40,498 | 40,314 | 40,131 | 39,948 | |
| 6 | Average Net Investment | | 42,057 | 41,873 | 41,690 | 41,506 | 41,323 | 41,140 | 40,956 | 40,773 | 40,590 | 40,406 | 40,223 | 40,039 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 227 | 226 | 225 | 224 | 223 | 222 | 225 | 224 | 223 | 222 | 221 | 220 | 2,684 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 66 | 66 | 66 | 66 | 65 | 65 | 59 | 59 | 58 | 58 | 58 | 58 | 745 |
| 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) | | 477 | 476 | 474 | 473 | 472 | 470 | 468 | 466 | 465 | 464 | 463 | 461 | 5,629 |
| | a Recoverable Costs Allocated to Energy | | 37 | 37 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 35 | 433 |
| | b Recoverable Costs Allocated to Demand | | 440 | 439 | 438 | 437 | 435 | 434 | 432 | 431 | 429 | 428 | 427 | 426 | 5,196 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 36 | 36 | 35 | 36 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 34 | 422 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 427 | 426 | 425 | 424 | 423 | 422 | 419 | 418 | 417 | 416 | 415 | 413 | 5,044 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 463 | 462 | 460 | 459 | 458 | 457 | 454 | 453 | 452 | 451 | 449 | 448 | 5,465 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E.s 1175, 1191, 1305, 1330, 1461, 1462
(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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | |
| 3 | Less: Accumulated Depreciation (C) | (6,348,520) | (6,433,001) | (6,517,483) | (6,601,964) | (6,686,445) | (6,770,926) | (6,855,408) | (6,939,889) | (7,024,370) | (7,108,852) | (7,193,333) | (7,277,814) | (7,362,296) | |
| 4 | 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) | 23,491,158 | 23,406,677 | 23,322,195 | 23,237,714 | 23,153,233 | 23,068,751 | 22,984,270 | 22,899,789 | 22,815,308 | 22,730,826 | 22,646,345 | 22,561,864 | 22,477,382 | |
| 6 | Average Net Investment | | 23,448,917 | 23,364,436 | 23,279,955 | 23,195,473 | 23,110,992 | 23,026,511 | 22,942,030 | 22,857,548 | 22,773,067 | 22,688,586 | 22,604,104 | 22,519,623 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 126,530 | 126,074 | 125,619 | 125,163 | 124,707 | 124,251 | 126,227 | 125,762 | 125,297 | 124,833 | 124,368 | 123,903 | 1,502,734 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 37,073 | 36,939 | 36,806 | 36,672 | 36,538 | 36,405 | 33,037 | 32,915 | 32,793 | 32,672 | 32,550 | 32,428 | 416,827 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 1,013,776 |
| | 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) | | 248,084 | 247,495 | 246,906 | 246,316 | 245,727 | 245,137 | 243,745 | 243,158 | 242,572 | 241,985 | 241,399 | 240,813 | 2,933,337 |
| | a Recoverable Costs Allocated to Energy | | 19,083 | 19,038 | 18,993 | 18,947 | 18,902 | 18,857 | 18,750 | 18,704 | 18,659 | 18,614 | 18,569 | 18,524 | 225,641 |
| | b Recoverable Costs Allocated to Demand | | 229,001 | 228,457 | 227,913 | 227,369 | 226,825 | 226,281 | 224,995 | 224,454 | 223,913 | 223,371 | 222,830 | 222,288 | 2,707,696 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 18,531 | 18,503 | 18,460 | 18,510 | 18,421 | 18,390 | 18,291 | 18,243 | 18,190 | 18,183 | 18,027 | 17,931 | 219,681 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 222,295 | 221,766 | 221,238 | 220,710 | 220,182 | 219,654 | 218,406 | 217,881 | 217,355 | 216,830 | 216,304 | 215,779 | 2,628,400 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 240,826 | 240,270 | 239,698 | 239,220 | 238,603 | 238,044 | 236,698 | 236,124 | 235,545 | 235,013 | 234,331 | 233,710 | 2,848,080 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist $13,997,696; Smith $15,715,201; Scholz $126,781.
(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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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 | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
Return on Capital Investments, Depreciation and Taxes
For Project: Plant 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 | | 0 | 0 | 0 | 0 | 0 | 0 | 15,978 | (70) | 72 | (160) | (11) | 3,176 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 15,908 | 72 | (160) | (11) | 3,176 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17,938 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 1,015 | (4) | 4 | (10) | 0 | (1) | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 20,025,602 | 20,025,602 | 20,025,602 | 20,025,602 | 20,025,602 | 20,025,602 | 20,025,602 | 20,025,602 | 20,041,510 | 20,023,644 | 20,023,484 | 20,023,473 | 20,026,649 | |
| 3 | Less: Accumulated Depreciation (C) | (2,590,907) | (2,649,322) | (2,707,736) | (2,766,151) | (2,824,566) | (2,882,980) | (2,941,395) | (2,998,794) | (3,057,213) | (3,097,732) | (3,156,151) | (3,214,560) | (3,272,969) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 15,978 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 17,434,695 | 17,376,280 | 17,317,865 | 17,259,451 | 17,201,036 | 17,142,621 | 17,084,206 | 17,042,786 | 16,984,297 | 16,925,912 | 16,867,333 | 16,808,914 | 16,753,680 | |
| 6 | Average Net Investment | | 17,405,487 | 17,347,073 | 17,288,658 | 17,230,243 | 17,171,829 | 17,113,414 | 17,063,496 | 17,013,541 | 16,955,104 | 16,896,623 | 16,838,123 | 16,781,297 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 93,920 | 93,605 | 93,290 | 92,974 | 92,659 | 92,344 | 93,883 | 93,609 | 93,287 | 92,965 | 92,643 | 92,331 | 1,117,510 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 27,518 | 27,426 | 27,333 | 27,241 | 27,149 | 27,056 | 24,571 | 24,499 | 24,415 | 24,331 | 24,247 | 24,165 | 309,953 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 58,415 | 58,415 | 58,415 | 58,415 | 58,415 | 58,415 | 58,415 | 58,415 | 58,461 | 58,409 | 58,409 | 58,408 | 701,005 |
| | 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) | | 179,853 | 179,445 | 179,038 | 178,630 | 178,223 | 177,815 | 176,869 | 176,523 | 176,163 | 175,705 | 175,299 | 174,904 | 2,128,467 |
| | a Recoverable Costs Allocated to Energy | | 13,835 | 13,803 | 13,772 | 13,741 | 13,709 | 13,678 | 13,605 | 13,579 | 13,551 | 13,516 | 13,485 | 13,454 | 163,728 |
| | b Recoverable Costs Allocated to Demand | | 166,018 | 165,642 | 165,266 | 164,889 | 164,513 | 164,137 | 163,264 | 162,944 | 162,612 | 162,190 | 161,814 | 161,450 | 1,964,739 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 13,434 | 13,416 | 13,385 | 13,424 | 13,361 | 13,339 | 13,273 | 13,244 | 13,210 | 13,203 | 13,091 | 13,024 | 159,403 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 161,156 | 160,791 | 160,426 | 160,060 | 159,695 | 159,330 | 158,483 | 158,172 | 157,850 | 157,440 | 157,075 | 156,722 | 1,907,201 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 174,590 | 174,206 | 173,811 | 173,484 | 173,056 | 172,669 | 171,756 | 171,416 | 171,060 | 170,643 | 170,166 | 169,746 | 2,066,604 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | (11) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | (11) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 6,153,151 | 6,153,151 | 6,153,151 | 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) | (1,537,831) | (1,555,780) | (1,573,728) | (1,591,677) | (1,609,626) | (1,627,574) | (1,645,523) | (1,663,472) | (1,681,421) | (1,699,369) | (1,717,318) | (1,735,267) | (1,753,215) | |
| 4 | CWIP - Non Interest Bearing | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 4,615,321 | 4,597,372 | 4,579,423 | 4,561,463 | 4,543,514 | 4,525,566 | 4,507,617 | 4,489,668 | 4,471,720 | 4,453,771 | 4,435,822 | 4,417,873 | 4,399,925 | |
| 6 | Average Net Investment | | 4,606,346 | 4,588,397 | 4,570,443 | 4,552,489 | 4,534,540 | 4,516,591 | 4,498,643 | 4,480,694 | 4,462,745 | 4,444,796 | 4,426,848 | 4,408,899 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 24,856 | 24,759 | 24,662 | 24,565 | 24,468 | 24,372 | 24,752 | 24,653 | 24,554 | 24,455 | 24,357 | 24,258 | 294,710 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 7,283 | 7,254 | 7,226 | 7,197 | 7,169 | 7,141 | 6,478 | 6,452 | 6,426 | 6,401 | 6,375 | 6,349 | 81,751 |
| 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) | | 50,087 | 49,962 | 49,837 | 49,711 | 49,586 | 49,461 | 49,178 | 49,054 | 48,929 | 48,804 | 48,680 | 48,555 | 591,845 |
| | a Recoverable Costs Allocated to Energy | | 3,853 | 3,843 | 3,834 | 3,824 | 3,814 | 3,805 | 3,783 | 3,773 | 3,764 | 3,754 | 3,745 | 3,735 | 45,527 |
| | b Recoverable Costs Allocated to Demand | | 46,234 | 46,119 | 46,003 | 45,887 | 45,772 | 45,656 | 45,395 | 45,280 | 45,165 | 45,050 | 44,935 | 44,820 | 546,319 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 3,741 | 3,735 | 3,726 | 3,736 | 3,717 | 3,710 | 3,690 | 3,680 | 3,669 | 3,667 | 3,635 | 3,616 | 44,324 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 44,880 | 44,768 | 44,656 | 44,544 | 44,431 | 44,319 | 44,066 | 43,954 | 43,843 | 43,731 | 43,619 | 43,508 | 530,320 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 48,622 | 48,503 | 48,382 | 48,279 | 48,149 | 48,030 | 47,756 | 47,635 | 47,512 | 47,398 | 47,255 | 47,123 | 574,643 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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, 1468, 1469, 1505, 1508, 1512, 1513, 1517, 1551, 1552, 1646, 1647, 1684, 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 | | 521,151 | 147,875 | 106,422 | 257,116 | 149,765 | 145,684 | 183,307 | 1,263,193 | 643,651 | 618,127 | 502,923 | 1,176,518 | |
| | b Clearings to Plant | | 505,648 | 691,559 | 90,322 | 5,349 | 13,831 | 24,009 | 133,230 | 11,383 | 1,204 | 1,365,225 | 559,508 | 6,118 | |
| | c Retirements | | 0 | 530,189 | 19,108 | 0 | 0 | 0 | 414,790 | 0 | 0 | 0 | 10,558 | (400,941) | |
| | d Cost of Removal | | 2,489 | (452) | (9,222) | 1,437 | 0 | 100,000 | (103,100) | 0 | 0 | 1,518 | 212 | 18,559 | |
| | e Salvage | | 114,596 | 0 | 0 | 0 | 0 | 0 | 343,789 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 798,124,333 | 798,629,980 | 798,791,351 | 798,862,565 | 798,867,914 | 798,881,745 | 798,905,754 | 798,624,194 | 798,635,577 | 798,636,781 | 800,002,007 | 800,550,957 | 800,958,016 | |
| 3 | Less: Accumulated Depreciation (C) | (113,263,148) | (116,021,932) | (118,140,347) | (120,779,073) | (123,426,232) | (126,074,820) | (128,623,420) | (131,304,131) | (133,951,916) | (136,599,699) | (139,245,966) | (141,886,963) | (144,922,714) | |
| 4 | CWIP - Non Interest Bearing | 696,557 | 712,060 | 168,375 | 184,475 | 436,241 | 572,175 | 693,850 | 743,927 | 1,995,737 | 2,638,185 | 1,891,086 | 1,834,502 | 3,004,902 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 685,557,741 | 683,320,108 | 680,819,379 | 678,267,967 | 675,877,923 | 673,379,100 | 670,976,183 | 668,063,990 | 666,679,398 | 664,675,267 | 662,647,127 | 660,498,495 | 659,040,204 | |
| 6 | Average Net Investment | | 684,438,924 | 682,069,743 | 679,543,673 | 677,072,945 | 674,628,512 | 672,177,642 | 669,520,087 | 667,371,694 | 665,677,333 | 663,661,197 | 661,572,811 | 659,769,350 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 3,693,232 | 3,680,448 | 3,666,818 | 3,653,486 | 3,640,295 | 3,627,071 | 3,683,700 | 3,671,879 | 3,662,557 | 3,651,464 | 3,639,974 | 3,630,051 | 43,900,974 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,082,098 | 1,078,352 | 1,074,359 | 1,070,452 | 1,066,588 | 1,062,713 | 964,109 | 961,015 | 958,575 | 955,672 | 952,665 | 950,068 | 12,176,666 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 2,313,337 | 2,314,812 | 2,315,273 | 2,315,257 | 2,315,249 | 2,315,261 | 2,315,273 | 2,314,446 | 2,314,443 | 2,314,446 | 2,318,428 | 2,320,029 | 27,786,253 |
| | b Amortization (F) | | 18,442 | 18,442 | 18,442 | 18,442 | 18,442 | 18,442 | 18,442 | 18,442 | 18,442 | 18,442 | 18,442 | 18,442 | 221,309 |
| | c Dismantlement | | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 3,778,764 |
| | d Property Taxes | | 128,360 | 128,360 | 128,360 | 128,360 | 128,360 | 128,360 | 128,360 | 128,360 | 128,360 | 128,360 | 357,556 | 149,196 | 1,790,351 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 7,550,367 | 7,535,312 | 7,518,148 | 7,500,894 | 7,483,831 | 7,466,744 | 7,424,781 | 7,409,040 | 7,397,274 | 7,383,281 | 7,601,962 | 7,382,683 | 89,654,317 |
| | a Recoverable Costs Allocated to Energy | | 580,797 | 579,639 | 578,319 | 576,992 | 575,679 | 574,365 | 571,137 | 569,926 | 569,021 | 567,945 | 584,766 | 567,899 | 6,896,486 |
| | b Recoverable Costs Allocated to Demand | | 6,969,569 | 6,955,673 | 6,939,829 | 6,923,902 | 6,908,152 | 6,892,379 | 6,853,644 | 6,839,114 | 6,828,253 | 6,815,337 | 7,017,196 | 6,814,785 | 82,757,831 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 563,988 | 563,352 | 562,084 | 563,670 | 561,038 | 560,140 | 557,179 | 555,862 | 554,711 | 554,791 | 567,687 | 549,730 | 6,714,233 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 6,765,463 | 6,751,973 | 6,736,593 | 6,721,133 | 6,705,844 | 6,690,533 | 6,652,932 | 6,638,827 | 6,628,285 | 6,615,747 | 6,811,694 | 6,615,211 | 80,334,235 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 7,329,451 | 7,315,325 | 7,298,677 | 7,284,802 | 7,266,882 | 7,250,673 | 7,210,111 | 7,194,690 | 7,182,996 | 7,170,538 | 7,379,381 | 7,164,941 | 87,048,468 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $778,413,719; Smith $12,931,385; Daniel $6,772,129, Scholz $7,099. Ending Balances: Crist $781,247,403; Smith $12,931,385; Daniel $6,772,129, Scholz $7,099.
(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 1222, PE 1233 and PE 1279 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 32,021 | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 32,021 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3 | Less: Accumulated Depreciation (C) | (32,021) | (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 | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1280 is fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - December 2014**
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 | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 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 Final True-Up Amount
**January 2014 - December 2014**
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 | 632,455 | 600,514 | 579,245 | 557,972 | 547,631 | 529,551 | 505,879 | 486,938 | 464,366 | 443,377 | 426,180 | 407,127 | (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 | 632,455 | 600,514 | 579,245 | 557,972 | 547,631 | 529,551 | 505,879 | 486,938 | 464,366 | 443,377 | 426,180 | 407,127 | 0 | |
| 4 | Average Net Working Capital Balance | | 616,485 | 589,880 | 568,609 | 552,802 | 538,591 | 517,715 | 496,408 | 475,652 | 453,871 | 434,779 | 416,653 | 203,563 | |
| 5 | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a Equity Component (Line 4 x Equity Component x 1/12) (A) | | 3,327 | 3,183 | 3,068 | 2,983 | 2,906 | 2,794 | 2,731 | 2,617 | 2,497 | 2,392 | 2,292 | 1,120 | 31,911 |
| | b Debt Component (Line 4 x Debt Component x 1/12) | | 975 | 933 | 899 | 874 | 852 | 819 | 715 | 685 | 654 | 626 | 600 | 293 | 8,923 |
| 6 | Total Return Component (D) | | 4,301 | 4,116 | 3,967 | 3,857 | 3,758 | 3,612 | 3,446 | 3,302 | 3,151 | 3,018 | 2,892 | 1,413 | 40,833 |
| 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 | | 31,941 | 21,269 | 21,273 | 10,341 | 18,080 | 23,672 | 18,941 | 22,572 | 20,989 | 17,197 | 19,053 | 407,127 | 632,455 |
| 8 | Net Expenses (E) | | 31,941 | 21,269 | 21,273 | 10,341 | 18,080 | 23,672 | 18,941 | 22,572 | 20,989 | 17,197 | 19,053 | 407,127 | 632,455 |
| 9 | Total System Recoverable Expenses (Lines 6 + 8) | | 36,242 | 25,385 | 25,240 | 14,198 | 21,837 | 27,284 | 22,387 | 25,874 | 24,140 | 20,215 | 21,946 | 408,540 | 673,288 |
| | a Recoverable Costs Allocated to Energy | | 32,272 | 21,586 | 21,578 | 10,638 | 18,369 | 23,950 | 19,207 | 22,826 | 21,231 | 17,429 | 19,276 | 407,236 | 635,596 |
| | b Recoverable Costs Allocated to Demand | | 3,970 | 3,799 | 3,662 | 3,560 | 3,469 | 3,334 | 3,181 | 3,048 | 2,908 | 2,786 | 2,670 | 1,304 | 37,692 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (B) | | 31,338 | 20,979 | 20,972 | 10,392 | 17,902 | 23,357 | 18,737 | 22,262 | 20,697 | 17,026 | 18,713 | 394,207 | 616,582 |
| 13 | Retail Demand-Related Recoverable Costs (C) | | 3,854 | 3,688 | 3,555 | 3,456 | 3,367 | 3,237 | 3,088 | 2,959 | 2,823 | 2,704 | 2,592 | 1,266 | 36,588 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 35,192 | 24,667 | 24,527 | 13,848 | 21,269 | 26,594 | 21,825 | 25,221 | 23,521 | 19,730 | 21,304 | 395,473 | 653,171 |

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x 1.0015 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 Final True-Up Amount
**January 2014 - December 2014**
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 | 3 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 1 | 1 | 1 | (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 | 3 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 1 | 1 | 1 | 0 | |
| 4 | Average Net Working Capital Balance | | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 1 | 1 | 1 | 1 | |
| 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 Seasonal NOx Allowance Expense | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 |
| 8 | Net Expenses (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 |
| 9 | Total System Recoverable Expenses (Lines 6 + 8) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 |
| | a Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (B) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 |
| 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 | 1 | 3 |

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x 1.0015 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 Final True-Up Amount
**January 2014 - December 2014**
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 | 552 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Working Capital | | | | | | | | | | | | | | |
| | a FERC 158.1 Allowance Inventory | 7,460,946 | 7,369,716 | 7,325,786 | 7,261,692 | 7,238,308 | 7,177,412 | 7,096,070 | 7,026,068 | 6,932,968 | 6,861,095 | 6,748,115 | 6,658,968 | 6,632,174 | |
| | 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 | (289,672) | (275,363) | (261,053) | (247,245) | (232,885) | (218,525) | (204,165) | (189,805) | (175,445) | (161,085) | (146,725) | (132,365) | (118,005) | |
| 3 | Total Working Capital Balance | 7,171,274 | 7,094,353 | 7,064,733 | 7,014,447 | 7,005,423 | 6,958,887 | 6,891,905 | 6,836,263 | 6,757,523 | 6,700,011 | 6,601,391 | 6,526,603 | 6,514,169 | |
| 4 | Average Net Working Capital Balance | | 7,132,814 | 7,079,543 | 7,039,590 | 7,009,935 | 6,982,155 | 6,925,396 | 6,864,084 | 6,796,893 | 6,728,767 | 6,650,701 | 6,563,997 | 6,520,386 | |
| 5 | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a Equity Component (Line 4 x Equity Component x 1/12) (A) | | 38,489 | 38,201 | 37,986 | 37,826 | 37,676 | 37,369 | 37,766 | 37,397 | 37,022 | 36,592 | 36,115 | 35,875 | 448,313 |
| | b Debt Component (Line 4 x Debt Component x 1/12) | | 11,277 | 11,193 | 11,130 | 11,083 | 11,039 | 10,949 | 9,884 | 9,788 | 9,689 | 9,577 | 9,452 | 9,389 | 124,450 |
| 6 | Total Return Component (D) | | 49,766 | 49,394 | 49,115 | 48,908 | 48,715 | 48,318 | 47,650 | 47,184 | 46,711 | 46,169 | 45,567 | 45,265 | 572,763 |
| 7 | Expenses | | | | | | | | | | | | | | |
| | a Gains | | (14,310) | (14,310) | (14,360) | (14,360) | (14,360) | (14,360) | (14,360) | (14,360) | (14,360) | (14,360) | (14,360) | (14,360) | (172,219) |
| | b Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c SO2 Allowance Expense | | 91,231 | 43,930 | 64,095 | 23,384 | 60,896 | 81,342 | 70,002 | 93,100 | 71,873 | 112,980 | 89,147 | 26,794 | 828,772 |
| 8 | Net Expenses (E) | | 76,921 | 29,620 | 49,735 | 9,024 | 46,536 | 66,982 | 55,642 | 78,740 | 57,513 | 98,620 | 74,787 | 12,434 | 656,553 |
| 9 | Total System Recoverable Expenses (Lines 6 + 8) | | 126,687 | 79,014 | 98,850 | 57,932 | 95,251 | 115,301 | 103,292 | 125,924 | 104,224 | 144,789 | 120,355 | 57,699 | 1,229,316 |
| | a Recoverable Costs Allocated to Energy | | 80,749 | 33,420 | 53,513 | 12,786 | 50,284 | 70,699 | 59,307 | 82,369 | 61,106 | 102,171 | 78,293 | 15,916 | 700,612 |
| | b Recoverable Costs Allocated to Demand | | 45,938 | 45,594 | 45,337 | 45,146 | 44,967 | 44,602 | 43,985 | 43,554 | 43,118 | 42,618 | 42,062 | 41,783 | 528,704 |
| 10 | Energy Jurisdictional Factor | | 0.9696032 | 0.9704449 | 0.9704710 | 0.9754476 | 0.9731075 | 0.9737735 | 0.9740997 | 0.9738627 | 0.9733914 | 0.9753775 | 0.9693395 | 0.9665578 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (B) | | 78,412 | 32,481 | 52,010 | 12,491 | 49,005 | 68,948 | 57,858 | 80,337 | 59,569 | 99,805 | 76,006 | 15,407 | 682,328 |
| 13 | Retail Demand-Related Recoverable Costs (C) | | 44,592 | 44,259 | 44,009 | 43,824 | 43,650 | 43,296 | 42,697 | 42,279 | 41,855 | 41,370 | 40,830 | 40,559 | 513,221 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 123,004 | 76,740 | 96,020 | 56,315 | 92,655 | 112,244 | 100,555 | 122,616 | 101,425 | 141,175 | 116,836 | 55,966 | 1,195,548 |

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x 1.0015 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.

**Schedule 9A**


**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2014 - June 2014**

**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 | 679,381 | 37.9719 | 4.86 | 1.8459 | 1.8459 | |
| 2 | Short-Term Debt | 45,467 | 2.5412 | 0.39 | 0.0099 | 0.0099 | |
| 3 | Preferred Stock | 54,427 | 3.0420 | 6.33 | 0.1925 | 0.3134 | |
| 4 | Common Stock | 659,268 | 36.8478 | 10.25 | 3.7769 | 6.1488 | |
| 5 | Customer Deposits | 22,074 | 1.2337 | 3.09 | 0.0381 | 0.0381 | |
| 6 | Deferred Taxes | 325,735 | 18.2060 | | | | |
| 7 | Investment Tax Credit | 2,815 | 0.1574 | 7.47 | 0.0118 | 0.0167 | |
| 8 | Total | 1,789,167 | 100.0000 | | 5.8751 | 8.3728 | 0.6977 |
| | ITC Component: | | | | | | |
| 9 | Debt | 679,381 | 48.7684 | 4.86 | 2.3708 | 0.0037 | |
| 10 | Equity-Preferred | 54,427 | 3.9070 | 6.33 | 0.2473 | 0.0006 | |
| 11 | -Common | 659,268 | 47.3246 | 10.25 | 4.8508 | 0.0124 | |
| 12 | | 1,393,076 | 100.0000 | | 7.4689 | 0.0167 | |
| | Breakdown of Revenue Requirement Rate of Return between Debt and Equity: | | | | | | |
| 13 | Total Debt Component (Lines 1, 2, 5, and 9) | | | | | 1.8976 | 0.1581 |
| 14 | Total Equity Component (Lines 3, 4, 10, and 11) | | | | | 6.4752 | 0.5396 |
| 15 | Total Revenue Requirement Rate of Return | | | | | 8.3728 | 0.6977 |

Column:
(1) Based on the May 2013 Surveillance Report, Schedule 4.
(2) Column (1) / Total Column (1)
(3) Based on the May 2013 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**



**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**July 2014 - December 2014**

**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 | 680,813 | 36.0280 | 4.70 | 1.6932 | 1.6932 | |
| 2 | Short-Term Debt | 24,978 | 1.3218 | 0.35 | 0.0046 | 0.0046 | |
| 3 | Preferred Stock | 79,703 | 4.2178 | 6.15 | 0.2596 | 0.4226 | |
| 4 | Common Stock | 698,675 | 36.9732 | 10.25 | 3.7898 | 6.1698 | |
| 5 | Customer Deposits | 21,600 | 1.1430 | 2.41 | 0.0275 | 0.0275 | |
| 6 | Deferred Taxes | 381,708 | 20.1996 | | | | |
| 7 | Investment Tax Credit | 2,202 | 0.1165 | 7.44 | 0.0087 | 0.0125 | |
| 8 | Total | 1,889,679 | 100.0000 | | 5.7834 | 8.3302 | 0.6942 |
| | ITC Component: | | | | | | |
| 9 | Debt | 680,813 | 46.6569 | 4.70 | 2.1928 | 0.0026 | |
| 10 | Equity-Preferred | 79,703 | 5.4621 | 6.15 | 0.3361 | 0.0006 | |
| 11 | -Common | 698,675 | 47.8810 | 10.25 | 4.9078 | 0.0093 | |
| 12 | | 1,459,191 | 100.0000 | | 7.4367 | 0.0125 | |
| | Breakdown of Revenue Requirement Rate of Return between Debt and Equity: | | | | | | |
| 13 | Total Debt Component (Lines 1, 2, 5, and 9) | | | | | 1.7279 | 0.1440 |
| 14 | Total Equity Component (Lines 3, 4, 10, and 11) | | | | | 6.6023 | 0.5502 |
| 15 | Total Revenue Requirement Rate of Return | | | | | 8.3302 | 0.6942 |

Column:
(1) Based on the May 2014 Surveillance Report, Schedule 4.
(2) Column (1) / Total Column (1)
(3) Based on the May 2014 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 1E**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period True-Up Amount
**January 2015 - December 2015**

| Line No. | | Period Amount ($) |
|---|---|---|
| 1 | Over/(Under) Recovery for the Current Period (Schedule 2E, Line 5 + 9) | (1,694,731) |
| 2 | Interest Provision (Schedule 2E, Line 6) | (4,397) |
| 3 | Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2016 - December 2016 (Lines 1 + 2) | (1,699,128) |

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 26
PARTY: GULF POWER COMPANY (GULF) – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-2

**Schedule 2E**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)

**January 2015 - December 2015**
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 | Projected July | Projected August | Projected September | Projected October | Projected November | Projected December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (Net of Revenue Taxes) | 12,051,728 | 11,482,115 | 10,349,767 | 10,967,361 | 13,473,645 | 15,350,713 | 16,084,852 | 15,936,450 | 14,083,640 | 11,617,351 | 10,605,930 | 11,863,932 | 153,867,483 |
| 2 | True-Up Provision (Order No. PSC-14-0643-FOF-EI) | (739,650) | (739,655) | (739,655) | (739,655) | (739,655) | (739,655) | (739,655) | (739,655) | (739,655) | (739,655) | (739,655) | (739,655) | (8,875,855) |
| 3 | **ECRC Revenues Applicable to Period (Lines 1 + 2)** | 11,312,078 | 10,742,460 | 9,610,112 | 10,227,706 | 12,733,990 | 14,611,058 | 15,345,197 | 15,196,795 | 13,343,985 | 10,877,696 | 9,866,275 | 11,124,277 | 144,991,628 |
| 4 | Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| | a O & M Activities (Schedule 5E, Line 9) | 1,639,616 | 3,112,918 | 2,337,186 | 1,629,036.41 | 1,854,911 | 2,461,321 | 3,064,299 | 2,415,959 | 2,204,239 | 1,645,605 | 1,632,875 | 2,334,167 | 26,332,132 |
| | b Capital Investment Projects (Schedule 7E, Line 9) | 9,610,120 | 9,592,780 | 9,575,496 | 9,557,677.19 | 9,540,394 | 9,524,712 | 9,414,873 | 9,403,880 | 9,394,341 | 10,263,179 | 12,007,759 | 12,469,652 | 120,354,863 |
| | c **Total Jurisdictional ECRC Costs** | 11,249,736 | 12,705,698 | 11,912,682 | 11,186,714 | 11,395,304 | 11,986,033 | 12,479,173 | 11,819,839 | 11,598,579 | 11,908,784 | 13,640,634 | 14,803,818 | 146,686,994 |
| 5 | **Over/(Under) Recovery (Line 3 - Line 4c)** | 62,342 | (1,963,238) | (2,302,570) | (959,008) | 1,338,685 | 2,625,026 | 2,866,025 | 3,376,956 | 1,745,406 | (1,031,087) | (3,774,359) | (3,679,541) | (1,695,366) |
| 6 | Interest Provision (Schedule 3E, Line 10) | (779) | (758) | (824) | (749) | (734) | (618) | (318) | (60) | 162 | 235 | 124 | (77) | (4,397) |
| 7 | Beginning Balance True-Up & Interest Provision | | | | | | | | | | | | | |
| | a Actual Total for True-Up Period 2014 | (3,142,723) | (2,341,510) | (3,565,852) | (5,129,592) | (5,349,059) | (3,271,461) | 92,610 | 3,697,972 | 7,814,523 | 10,299,745 | 10,008,548 | 6,973,967 | (3,142,723) |
| | b Final True-Up from January 2013 - December 2013 (Order No. PSC-14-0643-FOF-EI) | (6,645,915) | (6,645,915) | (6,645,915) | (6,645,915) | (6,645,915) | (6,645,915) | (6,645,915) | (6,645,915) | (6,645,915) | (6,645,915) | (6,645,915) | (6,645,915) | (6,645,915) |
| 8 | True-Up Collected/(Refunded) (see Line 2) | 739,650 | 739,655 | 739,655 | 739,655 | 739,655 | 739,655 | 739,655 | 739,655 | 739,655 | 739,655 | 739,655 | 739,655 | 8,875,855 |
| 9 | Adjustments | | | | 635 | (8) | 8 | | | | | | | 635 |
| 10 | End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8 + 9) | (8,987,425) | (10,211,767) | (11,775,507) | (11,994,974) | (9,917,376) | (6,553,305) | (2,947,943) | 1,168,608 | 3,653,830 | 3,362,633 | 328,052 | (2,611,911) | (2,611,911) |

**Schedule 3E**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period True-Up Amount
**January 2015 - December 2015**

**Interest Provision**
(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 | Beg. True-Up Amount (Schedule 2E, Lines 7a + 7b) | (9,788,638) | (8,987,425) | (10,211,767) | (11,775,507) | (11,994,974) | (9,917,376) | (6,553,305) | (2,947,943) | 1,168,608 | 3,653,830 | 3,362,633 | 328,052 | |
| 2 | Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8) | (8,986,646) | (10,211,009) | (11,774,683) | (11,994,860) | (9,916,634) | (6,552,695) | (2,947,625) | 1,168,667 | 3,653,669 | 3,362,398 | 327,928 | (2,611,834) | |
| 3 | Total of Beginning & Ending True-up (Lines 1 + 2) | (18,775,284) | (19,198,434) | (21,986,450) | (23,770,367) | (21,911,607) | (16,470,071) | (9,500,930) | (1,779,276) | 4,822,276 | 7,016,228 | 3,690,561 | (2,283,782) | |
| 4 | Average True-Up Amount (Line 3 x 1/2) | (9,387,642) | (9,599,217) | (10,993,225) | (11,885,184) | (10,955,804) | (8,235,035) | (4,750,465) | (889,638) | 2,411,138 | 3,508,114 | 1,845,281 | (1,141,891) | |
| 5 | Interest Rate (First Day of Reporting Business Month) | 0.0010 | 0.0010 | 0.0009 | 0.0009 | 0.0006 | 0.0010 | 0.0008 | 0.0008 | 0.0008 | 0.0008 | 0.0008 | 0.0008 | |
| 6 | Interest Rate (First Day of Subsequent Business Month) | 0.0010 | 0.0009 | 0.0009 | 0.0006 | 0.0010 | 0.0008 | 0.0008 | 0.0008 | 0.0008 | 0.0008 | 0.0008 | 0.0008 | |
| 7 | Total of Beginning and Ending Interest Rates (Line 5 + Line 6) | 0.0020 | 0.0019 | 0.0018 | 0.0015 | 0.0016 | 0.0018 | 0.0016 | 0.0016 | 0.0016 | 0.0016 | 0.0016 | 0.0016 | |
| 8 | Average Interest Rate (Line 7 x 1/2) | 0.00100 | 0.00095 | 0.00090 | 0.00075 | 0.00080 | 0.00090 | 0.00080 | 0.00080 | 0.00080 | 0.00080 | 0.00080 | 0.00080 | |
| 9 | Monthly Average Interest Rate (Line 8 x 1/12) | 0.000083 | 0.000079 | 0.000075 | 0.000063 | 0.000067 | 0.000075 | 0.000067 | 0.000067 | 0.000067 | 0.000067 | 0.000067 | 0.000067 | |
| 10 | Interest Provision for the Month (Line 4 x Line 9) | (779) | (758) | (824) | (749) | (734) | (618) | (318) | (60) | 162 | 235 | 124 | (77) | (4,397) |

**Schedule 4E**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
**January 2015 - December 2015**

**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 | 554,260 | 505,156 | 49,104 | 9.7 % |
| .3 | Title V | 154,361 | 142,158 | 12,203 | 8.6 % |
| .4 | Asbestos Fees | 600 | 1,500 | (900) | (60.0) % |
| .5 | Emission Monitoring | 720,484 | 807,348 | (86,864) | (10.8) % |
| .6 | General Water Quality | 1,324,083 | 2,139,535 | (815,453) | (38.1) % |
| .7 | Groundwater Contamination Investigation | 4,148,742 | 4,173,965 | (25,223) | (0.6) % |
| .8 | State NPDES Administration | 49,770 | 49,500 | 270 | 0.5 % |
| .9 | Lead and Copper Rule | 8,238 | 16,476 | (8,238) | (50.0) % |
| .10 | Env Auditing/Assessment | 7,922 | 9,000 | (1,078) | (12.0) % |
| .11 | General Solid & Hazardous Waste | 714,300 | 707,522 | 6,778 | 1.0 % |
| .12 | Above Ground Storage Tanks | 191,176 | 117,322 | 73,854 | 62.9 % |
| .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 | 64,296 | 105,903 | (41,607) | (39.3) % |
| .17 | Gulf Coast Ozone Study | 0 | 0 | 0 | 0.0 % |
| .18 | SPCC Substation Project | 0 | 0 | 0 | 0.0 % |
| .19 | FDEP NOx Reduction Agreement | 1,796,654 | 2,024,231 | (227,577) | (11.2) % |
| .20 | Air Quality Compliance Program | 16,929,325 | 16,556,451 | 372,874 | 2.3 % |
| .21 | MACT ICR* | (112,041) | 0 | (112,041) | 0.0 % |
| .22 | Crist Water Conservation | 237,387 | 299,302 | (61,915) | (20.7) % |
| .23 | Mercury Allowances | 0 | 0 | 0 | 0.0 % |
| .24 | Annual NOx Allowances | 0 | 97,897 | (97,897) | (100.0) % |
| .25 | Seasonal NOx Allowances | 0 | 1 | (1) | (61.0) % |
| .26 | SO2 Allowances | 286,653 | 350,060 | (63,407) | (18.1) % |
| 2 | Total O & M Activities | 27,076,209 | 28,103,327 | (1,027,118) | (3.7) % |
| 3 | Recoverable Costs Allocated to Energy | 20,393,991 | 20,589,205 | (195,214) | (0.9) % |
| 4 | Recoverable Costs Allocated to Demand | 6,682,218 | 7,514,122 | (831,904) | (11.1) % |

Notes:
* Line 1.21 - O&M amounts presented on Line 1.21 are related to the Air Quality Compliance Program. A 2015 entry was made to transfer the O&M amounts to the proper account.
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-14-0643-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 2015 - December 2015**

**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 | 0 | 0 | 404,260 | 0 | 0 | 0 | 0 | 150,000 | 0 | 0 | 0 | 0 | 554,260 | 0 | 554,260 |
| . 3 | Title V | 12,253 | 11,798 | 21,892 | 10,473 | 11,765 | 13,246 | 11,137 | 11,137 | 16,748 | 11,637 | 11,137 | 11,137 | 154,361 | 0 | 154,361 |
| . 4 | Asbestos Fees | 600 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 600 | 600 | 0 |
| . 5 | Emission Monitoring | 48,432 | 46,695 | 79,618 | 59,621 | 70,830 | 51,780 | 58,200 | 56,700 | 71,772 | 61,413 | 56,006 | 59,418 | 720,484 | 0 | 720,484 |
| . 6 | General Water Quality | 130,875 | (7,179) | 77,471 | 165,144 | 86,361 | 53,725 | 97,381 | 108,247 | 155,877 | 157,171 | 151,050 | 147,961 | 1,324,083 | 1,324,083 | 0 |
| . 7 | Groundwater Contamination Investigation | 68,481 | 90,779 | 88,746 | 137,240 | 491,215 | 603,731 | 1,155,565 | 638,613 | 225,849 | 240,681 | 209,396 | 198,446 | 4,148,742 | 4,148,742 | 0 |
| . 8 | State NPDES Administration | 0 | 34,770 | 15,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 49,770 | 49,770 | 0 |
| . 9 | Lead and Copper Rule | 0 | 0 | 0 | 0 | 0 | 0 | 1,373 | 1,373 | 1,373 | 1,373 | 1,373 | 1,373 | 8,238 | 8,238 | 0 |
| . 10 | Env Auditing/Assessment | 35 | 2,000 | 0 | 2,138 | (751) | 0 | 750 | 750 | 750 | 750 | 750 | 750 | 7,922 | 7,922 | 0 |
| . 11 | General Solid & Hazardous Waste | 45,619 | 45,219 | 60,905 | 51,060 | 82,528 | 83,542 | 55,520 | 55,520 | 65,813 | 57,520 | 54,524 | 56,531 | 714,300 | 714,300 | 0 |
| . 12 | Above Ground Storage Tanks | 51,284 | 13,304 | 11,040 | 1,832 | 1,678 | 2,350 | 10,877 | 23,483 | 16,953 | 24,457 | 24,457 | 9,461 | 191,176 | 191,176 | 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 | 9,136 | 3,533 | 15,589 | 3,975 | 14,706 | 3,091 | 14,266 | 64,296 | 0 | 64,296 |
| . 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 | 181,597 | 152,674 | 163,198 | 132,850 | 108,324 | 141,718 | 169,957 | 160,223 | 168,058 | 154,426 | 143,204 | 120,426 | 1,796,654 | 0 | 1,796,654 |
| . 20 | Air Quality Compliance Program | 1,126,863 | 2,761,600 | 1,545,323 | 1,078,696 | 1,007,714 | 1,522,927 | 1,529,091 | 1,198,487 | 1,487,910 | 928,985 | 983,825 | 1,757,903 | 16,929,325 | 0 | 16,929,325 |
| . 21 | MACT ICR | 3,098 | 5,615 | (112,926) | (8,075) | 0 | 246 | 0 | 0 | 0 | 0 | 0 | 0 | (112,041) | 0 | (112,041) |
| . 22 | Crist Water Conservation | 3,870 | 4,827 | 17,029 | 30,776 | 22,609 | 25,213 | 20,227 | 24,394 | 25,073 | 20,851 | 18,815 | 23,701 | 237,387 | 237,387 | 0 |
| . 23 | Mercury Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 24 | Annual NOx Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 25 | Seasonal NOx Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 26 | SO2 Allowances | 16,063 | 41,651 | 29,527 | 11,467 | 23,228 | 19,778 | 36,697 | 39,348 | 24,696 | 18,571 | 22,380 | 3,247 | 286,653 | 0 | 286,653 |
| 2 | Total of O & M Activities | 1,689,071 | 3,203,752 | 2,401,084 | 1,673,222 | 1,905,502 | 2,527,392 | 3,150,307 | 2,483,863 | 2,264,848 | 1,692,541 | 1,680,007 | 2,404,619 | 27,076,209 | 6,682,218 | 20,393,991 |
| 3 | Recoverable Costs Allocated to Energy | 1,388,305 | 3,020,033 | 2,130,892 | 1,285,031 | 1,221,862 | 1,758,831 | 1,808,615 | 1,631,484 | 1,773,160 | 1,189,739 | 1,219,643 | 1,966,397 | 20,393,991 | | |
| 4 | Recoverable Costs Allocated to Demand | 300,766 | 183,719 | 270,192 | 388,191 | 683,640 | 768,561 | 1,341,692 | 852,379 | 491,689 | 502,802 | 460,364 | 438,222 | 6,682,218 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | 1,347,659 | 2,934,579 | 2,074,907 | 1,252,214 | 1,191,291 | 1,715,268 | 1,761,899 | 1,588,542 | 1,726,949 | 1,157,527 | 1,185,993 | 1,908,778 | 19,845,605 | | |
| 8 | Jurisdictional Demand Recoverable Costs (B) | 291,958 | 178,339 | 262,279 | 376,823 | 663,619 | 746,053 | 1,302,400 | 827,417 | 477,289 | 488,077 | 446,882 | 425,389 | 6,486,526 | | |
| 9 | Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8) | 1,639,616 | 3,112,918 | 2,337,186 | 1,629,036 | 1,854,911 | 2,461,321 | 3,064,299 | 2,415,959 | 2,204,239 | 1,645,605 | 1,632,875 | 2,334,167 | 26,332,132 | | |

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 2015 - December 2015**

**Variance Report of Capital Investment Projects - Recoverable Costs**
(in Dollars)

| Line | | (1) Estimated/ Actual | (2) Original Projected | (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 | 4,376,835 | 4,357,657 | 19,178 | 0.4 | % |
| .3 | Crist 7 Flue Gas Conditioning | 122,341 | 120,961 | 1,379 | 1.1 | % |
| .4 | Low NOx Burners, Crist 6 & 7 | 1,656,586 | 1,594,097 | 62,489 | 3.9 | % |
| .5 | CEMS - Plants Crist, Scholz, Smith, & Daniel | 1,023,266 | 1,029,523 | (6,257) | (0.6) | % |
| .6 | Substation Contamination Remediation | 226,816 | 228,423 | (1,607) | (0.7) | % |
| .7 | Raw Water Well Flowmeters - Plants Crist & Smith | 18,756 | 18,848 | (92) | (0.5) | % |
| .8 | Crist Cooling Tower Cell | 42,756 | 41,176 | 1,580 | 3.8 | % |
| .9 | Crist Dechlorination System | 28,630 | 28,853 | (223) | (0.8) | % |
| .10 | Crist Diesel Fuel Oil Remediation | 4,628 | 4,647 | (19) | (0.4) | % |
| .11 | Crist Bulk Tanker Unload Sec Contain Struc | 6,054 | 6,076 | (22) | (0.4) | % |
| .12 | Crist IWW Sampling System | 3,525 | 3,538 | (12) | (0.4) | % |
| .13 | Sodium Injection System | 33,728 | 33,906 | (178) | (0.5) | % |
| .14 | Smith Stormwater Collection System | 179,770 | 180,539 | (769) | (0.4) | % |
| .15 | Smith Waste Water Treatment Facility | 25,889 | 26,066 | (178) | (0.7) | % |
| .16 | Daniel Ash Management Project | 1,471,108 | 1,467,244 | 3,864 | 0.3 | % |
| .17 | Smith Water Conservation | 1,217,335 | 1,544,231 | (326,895) | (21.2) | % |
| .18 | Underground Fuel Tank Replacement | 0 | 0 | 0 | 0.0 | % |
| .19 | Crist FDEP Agreement for Ozone Attainment | 12,380,363 | 12,283,029 | 97,334 | 0.8 | % |
| .20 | SPCC Compliance | 87,671 | 88,156 | (485) | (0.6) | % |
| .21 | Crist Common FTIR Monitor | 5,409 | 5,437 | (28) | (0.5) | % |
| .22 | Precipitator Upgrades for CAM Compliance | 2,827,978 | 2,844,006 | (16,027) | (0.6) | % |
| .23 | Plant Groundwater Contamination | 0 | 0 | 0 | 0.0 | % |
| .24 | Crist Water Conservation | 2,055,402 | 2,069,243 | (13,842) | (0.7) | % |
| .25 | Plant NPDES Permit Compliance Projects | 569,817 | 572,945 | (3,128) | (0.5) | % |
| .26 | Air Quality Compliance Program | 95,072,232 | 90,491,134 | 4,581,098 | 5.1 | % |
| .27 | General Water Quality | 0 | 0 | 0 | 0.0 | % |
| .28 | Mercury Allowances | 0 | 0 | 0 | 0.0 | % |
| .29 | Annual NOx Allowances | 0 | 28,966 | (28,966) | (100.0) | % |
| .30 | Seasonal NOx Allowances | 0 | 0 | 0 | 0.0 | % |
| .31 | SO2 Allowances | 525,155 | 529,219 | (4,064) | (0.8) | % |
| 2 | Total Investment Projects - Recoverable Costs | 123,962,048 | 119,597,918 | 4,364,129 | 3.6 | % |
| 3 | Recoverable Costs Allocated to Energy | 9,535,542 | 9,199,840 | 335,702 | 3.6 | % |
| 4 | Recoverable Costs Allocated to Demand | 114,426,506 | 110,398,078 | 4,028,428 | 3.6 | % |

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-14-0643-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
**Calculation of the Current Period Estimated True-up Amount**
**January 2015 - December 2015**

**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 | 370,682 | 369,933 | 369,209 | 368,484 | 367,763 | 367,177 | 362,342 | 361,726 | 360,988 | 360,249 | 359,510 | 358,772 | 4,376,835 | 4,040,156 | 336,680 |
| . 3 | Crist 7 Flue Gas Conditioning | 10,292 | 10,291 | 10,289 | 10,288 | 10,286 | 10,285 | 10,105 | 10,104 | 10,102 | 10,101 | 10,099 | 10,098 | 122,341 | 112,930 | 9,411 |
| . 4 | Low NOx Burners, Crist 6 & 7 | 134,572 | 134,707 | 134,882 | 135,188 | 135,088 | 136,384 | 137,804 | 138,536 | 139,275 | 141,423 | 143,188 | 145,538 | 1,656,586 | 1,529,156 | 127,430 |
| . 5 | CEMS - Plants Crist, Scholz, Smith, & Daniel | 86,638 | 86,491 | 86,345 | 86,198 | 86,051 | 85,905 | 84,633 | 84,489 | 84,345 | 84,201 | 84,057 | 83,913 | 1,023,266 | 944,553 | 78,713 |
| . 6 | Substation Contamination Remediation | 19,207 | 19,176 | 19,145 | 19,113 | 19,082 | 19,046 | 18,751 | 18,720 | 18,690 | 18,659 | 18,628 | 18,598 | 226,816 | 209,368 | 17,447 |
| . 7 | Raw Water Well Flowmeters - Plants Crist & Smith | 1,597 | 1,592 | 1,588 | 1,583 | 1,578 | 1,573 | 1,553 | 1,548 | 1,543 | 1,539 | 1,534 | 1,529 | 18,756 | 17,314 | 1,443 |
| . 8 | Crist Cooling Tower Cell | 3,600 | 3,599 | 3,597 | 3,596 | 3,595 | 3,594 | 3,532 | 3,531 | 3,530 | 3,529 | 3,527 | 3,526 | 42,756 | 39,467 | 3,289 |
| . 9 | Crist Declilorination System | 2,439 | 2,432 | 2,424 | 2,416 | 2,409 | 2,401 | 2,370 | 2,363 | 2,355 | 2,348 | 2,340 | 2,333 | 28,630 | 26,427 | 2,202 |
| . 10 | Crist Diesel Fuel Oil Remediation | 395 | 394 | 392 | 391 | 389 | 388 | 383 | 382 | 381 | 379 | 378 | 376 | 4,628 | 4,272 | 356 |
| . 11 | Crist Bulk Tanker Unload Sec Contain Struc | 518 | 516 | 514 | 511 | 509 | 507 | 502 | 500 | 498 | 496 | 494 | 491 | 6,054 | 5,588 | 466 |
| . 12 | Crist IWW Sampling System | 301 | 300 | 299 | 298 | 297 | 295 | 292 | 291 | 290 | 289 | 287 | 286 | 3,525 | 3,254 | 271 |
| . 13 | Sodium Injection System | 2,868 | 2,861 | 2,853 | 2,845 | 2,837 | 2,829 | 2,792 | 2,784 | 2,776 | 2,769 | 2,761 | 2,753 | 33,728 | 31,133 | 2,594 |
| . 14 | Smith Stormwater Collection System | 15,337 | 15,284 | 15,231 | 15,178 | 15,125 | 15,071 | 14,888 | 14,836 | 14,783 | 14,731 | 14,679 | 14,627 | 179,770 | 165,942 | 13,828 |
| . 15 | Smith Waste Water Treatment Facility | 2,191 | 2,188 | 2,184 | 2,181 | 2,177 | 2,174 | 2,141 | 2,137 | 2,134 | 2,131 | 2,127 | 2,124 | 25,889 | 23,897 | 1,991 |
| . 16 | Daniel Ash Management Project | 124,748 | 124,443 | 124,138 | 123,834 | 123,529 | 123,225 | 121,946 | 121,647 | 121,348 | 121,049 | 120,750 | 120,450 | 1,471,108 | 1,357,946 | 113,162 |
| . 17 | Smith Water Conservation | 97,378 | 98,570 | 98,068 | 97,526 | 97,666 | 97,838 | 97,673 | 100,623 | 103,573 | 106,523 | 109,473 | 112,423 | 1,217,335 | 1,123,694 | 93,641 |
| . 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 | 1,050,222 | 1,047,510 | 1,044,894 | 1,042,269 | 1,039,440 | 1,037,411 | 1,024,579 | 1,022,644 | 1,020,786 | 1,019,269 | 1,016,898 | 1,014,441 | 12,380,363 | 11,428,027 | 952,336 |
| . 20 | SPCC Compliance | 7,450 | 7,431 | 7,413 | 7,394 | 7,375 | 7,356 | 7,255 | 7,237 | 7,218 | 7,199 | 7,181 | 7,162 | 87,671 | 80,927 | 6,744 |
| . 21 | Crist Common FTIR Monitor | 460 | 459 | 458 | 456 | 455 | 454 | 448 | 446 | 445 | 444 | 443 | 441 | 5,409 | 4,993 | 416 |
| . 22 | Precipitator Upgrades for CAM Compliance | 240,226 | 239,640 | 239,053 | 238,467 | 237,880 | 237,294 | 234,010 | 233,434 | 232,858 | 232,282 | 231,706 | 231,130 | 2,827,978 | 2,610,442 | 217,537 |
| . 23 | Plant Groundwater Investigation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 24 | Crist Water Conservation | 174,519 | 174,105 | 173,700 | 173,295 | 172,889 | 172,484 | 170,064 | 169,666 | 169,267 | 168,869 | 168,471 | 168,073 | 2,055,402 | 1,897,294 | 158,108 |
| . 25 | Plant NPDES Permit Compliance Projects | 48,431 | 48,306 | 48,181 | 48,057 | 47,932 | 47,808 | 47,156 | 47,034 | 46,911 | 46,789 | 46,667 | 46,544 | 569,817 | 525,985 | 43,832 |
| . 26 | Air Quality Compliance Program | 7,460,803 | 7,446,217 | 7,432,450 | 7,418,956 | 7,406,088 | 7,392,746 | 7,307,709 | 7,297,565 | 7,288,343 | 8,182,991 | 9,980,601 | 10,457,764 | 95,072,232 | 87,758,983 | 7,313,249 |
| . 27 | General Water Quality | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 28 | Mercury Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 29 | Annual NOx Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 30 | Seasonal NOx Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (0) | (0) |
| . 31 | SO2 Allowances | 45,166 | 44,965 | 44,718 | 44,576 | 44,455 | 44,305 | 43,328 | 43,067 | 42,846 | 42,699 | 42,559 | 42,472 | 525,155 | 484,759 | 40,397 |
| 2 | Total Investment Projects - Recoverable Costs | 9,900,041 | 9,881,409 | 9,862,024 | 9,843,099 | 9,824,896 | 9,808,551 | 9,696,255 | 9,685,309 | 9,675,286 | 10,570,955 | 12,368,358 | 12,845,864 | 123,962,048 | 114,426,506 | 9,535,542.13 |
| 3 | Recoverable Costs Allocated to Energy | 761,542 | 760,108.39 | 758,617 | 757,161 | 755,761 | 754,504 | 745,866 | 745,024 | 744,253 | 813,150 | 951,412 | 988,143 | 9,535,542 | | |
| 4 | Recoverable Costs Allocated to Demand | 9,138,499 | 9,121,300.73 | 9,103,407 | 9,085,938 | 9,069,135 | 9,054,047 | 8,950,389 | 8,940,286 | 8,931,033 | 9,757,805 | 11,416,946 | 11,857,721 | 114,426,506 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | 739,245 | 738,600.50 | 738,686 | 737,825 | 736,852 | 735,816 | 726,600 | 725,414 | 724,857 | 791,135 | 925,163 | 959,189 | 9,279,383 | | |
| 8 | Jurisdictional Demand Recoverable Costs (C) | 8,870,875 | 8,854,179.79 | 8,836,810 | 8,819,852 | 8,803,541 | 8,788,895 | 8,688,273 | 8,678,466 | 8,669,484 | 9,472,044 | 11,082,596 | 11,510,463 | 111,075,480 | | |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | 9,610,120 | 9,592,780 | 9,575,496 | 9,557,677 | 9,540,394 | 9,524,712 | 9,414,873 | 9,403,880 | 9,394,341 | 10,263,179 | 12,007,759 | 12,469,652 | 120,354,863 | | |

Notes:

(A) Pages 1-27 of Schedule 8E, Line 9, Pages 28-31 of Schedule 8E, Line 6
(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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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 | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 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 2015 - December 2015**
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 | 7,287 | (84) | 8,343 | 38,830 | 19,474 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 101,266 | 19,474 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 33,557,261 | 33,557,261 | 33,557,261 | 33,557,261 | 33,557,261 | 33,557,261 | 33,658,527 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | |
| 3 | Less: Accumulated Depreciation (C) | 4,292,959 | 4,184,984 | 4,077,008 | 3,969,033 | 3,861,057 | 3,753,082 | 3,645,106 | 3,536,835 | 3,428,507 | 3,320,180 | 3,211,852 | 3,103,524 | 2,995,197 | |
| 4 | CWIP - Non Interest Bearing | 46,889 | 46,889 | 46,889 | 46,889 | 54,176 | 54,092 | 62,436 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 37,897,109 | 37,789,134 | 37,681,158 | 37,580,470 | 37,472,411 | 37,372,778 | 37,303,633 | 37,214,836 | 37,106,509 | 36,998,181 | 36,889,853 | 36,781,525 | 36,673,198 | |
| 6 | Average Net Investment | | 37,843,122 | 37,735,146 | 37,630,814 | 37,526,440 | 37,422,595 | 37,338,206 | 37,259,235 | 37,160,672 | 37,052,345 | 36,944,017 | 36,835,689 | 36,727,362 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 208,213 | 207,619 | 207,045 | 206,470 | 205,899 | 205,435 | 202,355 | 201,820 | 201,231 | 200,643 | 200,055 | 199,466 | 2,446,250 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 54,494 | 54,339 | 54,188 | 54,038 | 53,889 | 53,767 | 51,716 | 51,579 | 51,429 | 51,278 | 51,128 | 50,978 | 632,822 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 97,887 | 97,886.53 | 97,887 | 97,887 | 97,887 | 97,887 | 98,182 | 98,239 | 98,239 | 98,239 | 98,239 | 98,239 | 1,176,695 |
| | 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 | 10,089 | 10,089 | 10,089 | 10,089 | 10,089 | 10,089 | 121,068 |
| | 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) | | 370,682 | 369,933 | 369,209 | 368,484 | 367,763 | 367,177 | 362,342 | 361,726 | 360,988 | 360,249 | 359,510 | 358,772 | 4,376,835 |
| | a Recoverable Costs Allocated to Energy | | 28,514 | 28,456 | 28,401 | 28,345 | 28,289 | 28,244 | 27,872 | 27,825 | 27,768 | 27,711 | 27,655 | 27,598 | 336,680 |
| | b Recoverable Costs Allocated to Demand | | 342,168 | 341,477 | 340,808 | 340,139 | 339,474 | 338,933 | 334,469 | 333,901 | 333,219 | 332,538 | 331,856 | 331,174 | 4,040,156 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 27,679 | 27,651 | 27,654 | 27,621 | 27,582 | 27,545 | 27,152 | 27,093 | 27,045 | 26,961 | 26,892 | 26,789 | 327,664 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 332,148 | 331,476 | 330,827 | 330,178 | 329,532 | 329,007 | 324,674 | 324,123 | 323,461 | 322,799 | 322,137 | 321,475 | 3,921,838 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 359,827 | 359,127 | 358,482 | 357,799 | 357,114 | 356,552 | 351,827 | 351,216 | 350,506 | 349,760 | 349,029 | 348,264 | 4,249,502 |

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 1.0015 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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | 1,452,046 | 1,451,833 | 1,451,620 | 1,451,407 | 1,451,194 | 1,450,981 | 1,450,768 | 1,450,555 | 1,450,342 | 1,450,129 | 1,449,916 | 1,449,703 | 1,449,490 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 1,452,046 | 1,451,833 | 1,451,620 | 1,451,407 | 1,451,194 | 1,450,981 | 1,450,768 | 1,450,555 | 1,450,342 | 1,450,129 | 1,449,916 | 1,449,703 | 1,449,490 | |
| 6 | Average Net Investment | | 1,451,940 | 1,451,727 | 1,451,514 | 1,451,301 | 1,451,088 | 1,450,875 | 1,450,662 | 1,450,449 | 1,450,236 | 1,450,023 | 1,449,810 | 1,449,597 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 7,989 | 7,987 | 7,986 | 7,985 | 7,984 | 7,983 | 7,879 | 7,877 | 7,876 | 7,875 | 7,874 | 7,873 | 95,168 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 2,091 | 2,090 | 2,090 | 2,090 | 2,090 | 2,089 | 2,014 | 2,013 | 2,013 | 2,013 | 2,012 | 2,012 | 24,617 |
| 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 | 213 | 213 | 213 | 213 | 213 | 213 | 2,556 |
| | 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) | | 10,292 | 10,291 | 10,289 | 10,288 | 10,286 | 10,285 | 10,105 | 10,104 | 10,102 | 10,101 | 10,099 | 10,098 | 122,341 |
| | a Recoverable Costs Allocated to Energy | | 792 | 792 | 791 | 791 | 791 | 791 | 777 | 777 | 777 | 777 | 777 | 777 | 9,411 |
| | b Recoverable Costs Allocated to Demand | | 9,501 | 9,499 | 9,498 | 9,497 | 9,495 | 9,494 | 9,328 | 9,326 | 9,325 | 9,324 | 9,322 | 9,321 | 112,930 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 769 | 769 | 771 | 771 | 771 | 772 | 757 | 757 | 757 | 756 | 755 | 754 | 9,159 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 9,222 | 9,221 | 9,220 | 9,218 | 9,217 | 9,216 | 9,055 | 9,053 | 9,052 | 9,051 | 9,049 | 9,048 | 109,623 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 9,991 | 9,990 | 9,990 | 9,990 | 9,989 | 9,987 | 9,812 | 9,810 | 9,809 | 9,807 | 9,805 | 9,802 | 118,781 |

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 1.0015 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 2015 - December 2015**
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 | | 54,596 | 684 | 111,525 | (1,776) | 36,675 | 394,722 | 115,308 | 103,115 | 179,268 | 494,515 | 37,415 | 37,038 | |
| | b Clearings to Plant | | 54,596 | 684 | 48,618 | 18,464 | 5,513 | 611,444 | 73,346 | 949 | 26,982 | 61,692 | 799,592 | 37,038 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 10,271,976 | 10,326,572 | 10,327,257 | 10,375,874 | 10,394,338 | 10,399,851 | 11,011,295 | 11,084,641 | 11,085,590 | 11,112,572 | 11,174,264 | 11,973,856 | 12,010,894 | |
| 3 | Less: Accumulated Depreciation (C) | 4,458,285 | 4,427,273 | 4,396,101 | 4,364,928 | 4,333,613 | 4,302,302 | 4,270,974 | 4,237,885 | 4,204,582 | 4,171,276 | 4,137,892 | 4,104,327 | 4,068,431 | |
| 4 | CWIP - Non Interest Bearing | 175,834 | 175,834 | 175,834 | 238,741 | 218,501 | 249,662 | 32,940 | 74,902 | 177,068 | 329,354 | 762,177 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 14,906,094 | 14,929,678 | 14,899,191 | 14,979,543 | 14,946,452 | 14,951,815 | 15,315,210 | 15,397,429 | 15,467,241 | 15,613,203 | 16,074,333 | 16,078,184 | 16,079,325 | |
| 6 | Average Net Investment | | 14,917,886 | 14,914,435 | 14,939,367 | 14,962,998 | 14,949,134 | 15,133,513 | 15,356,319 | 15,432,335 | 15,540,222 | 15,843,768 | 16,076,259 | 16,078,754 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 82,078 | 82,059 | 82,196 | 82,326 | 82,250 | 83,265 | 83,400 | 83,813 | 84,399 | 86,048 | 87,310 | 87,324 | 1,006,468 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 21,482 | 21,477 | 21,513 | 21,547 | 21,527 | 21,792 | 21,315 | 21,420 | 21,570 | 21,991 | 22,314 | 22,317 | 260,264 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 29,623 | 29,782 | 29,784 | 29,926 | 29,922 | 29,938 | 31,700 | 31,914 | 31,917 | 31,996 | 32,175 | 34,508 | 373,186 |
| | b Amortization (F) | | 1,389 | 1,389 | 1,389 | 1,389 | 1,389 | 1,389 | 1,389 | 1,389 | 1,389 | 1,389 | 1,389 | 1,389 | 16,668 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | | 134,572 | 134,707 | 134,882 | 135,188 | 135,088 | 136,384 | 137,804 | 138,536 | 139,275 | 141,423 | 143,188 | 145,538 | 1,656,586 |
| | a Recoverable Costs Allocated to Energy | | 10,352 | 10,362 | 10,376 | 10,399 | 10,391 | 10,491 | 10,600 | 10,657 | 10,713 | 10,879 | 11,014 | 11,195 | 127,430 |
| | b Recoverable Costs Allocated to Demand | | 124,220 | 124,345 | 124,507 | 124,789 | 124,697 | 125,893 | 127,204 | 127,879 | 128,561 | 130,544 | 132,174 | 134,343 | 1,529,156 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 10,049 | 10,069 | 10,103 | 10,134 | 10,131 | 10,231 | 10,326 | 10,376 | 10,434 | 10,584 | 10,711 | 10,867 | 124,015 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 120,582 | 120,704 | 120,861 | 121,135 | 121,045 | 122,206 | 123,478 | 124,134 | 124,796 | 126,721 | 128,303 | 130,408 | 1,484,374 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 130,631 | 130,773 | 130,964 | 131,268 | 131,176 | 132,438 | 133,805 | 134,511 | 135,230 | 137,306 | 139,014 | 141,276 | 1,608,390 |

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 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 1.0015 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 2015 - December 2015**
Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, & 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, 1440, 1441, 1442, 1444, 1445, 1454, 1459, 1460, 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 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | 7,278,210 | |
| 3 | Less: Accumulated Depreciation (C) | 2,005,326 | 1,984,198 | 1,963,070 | 1,941,941 | 1,920,813 | 1,899,685 | 1,878,556 | 1,857,428 | 1,836,299 | 1,815,171 | 1,794,043 | 1,772,914 | 1,751,786 | |
| 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) (A) | 9,283,537 | 9,262,408 | 9,241,280 | 9,220,152 | 9,199,023 | 9,177,895 | 9,156,767 | 9,135,638 | 9,114,510 | 9,093,381 | 9,072,253 | 9,051,125 | 9,029,996 | |
| 6 | Average Net Investment | | 9,272,973 | 9,251,844 | 9,230,716 | 9,209,587 | 9,188,459 | 9,167,331 | 9,146,202 | 9,125,074 | 9,103,946 | 9,082,817 | 9,061,689 | 9,040,560 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 51,020 | 50,904 | 50,787 | 50,671 | 50,555 | 50,439 | 49,673 | 49,558 | 49,444 | 49,329 | 49,214 | 49,099 | 600,693 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 13,353 | 13,323 | 13,292 | 13,262 | 13,231 | 13,201 | 12,695 | 12,666 | 12,636 | 12,607 | 12,578 | 12,548 | 155,392 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 21,033 | 21,032.63 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 21,033 | 252,392 |
| | b Amortization (F) | | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 1,149 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 1,137 | 1,137 | 1,137 | 1,137 | 1,137 | 1,137 | 1,137 | 1,137 | 1,137 | 1,137 | 1,137 | 1,137 | 13,641 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 86,638 | 86,491 | 86,345 | 86,198 | 86,051 | 85,905 | 84,633 | 84,489 | 84,345 | 84,201 | 84,057 | 83,913 | 1,023,266 |
| | a Recoverable Costs Allocated to Energy | | 6,664 | 6,653 | 6,642 | 6,631 | 6,619 | 6,608 | 6,510 | 6,499 | 6,488 | 6,477 | 6,466 | 6,455 | 78,713 |
| | b Recoverable Costs Allocated to Demand | | 79,974 | 79,838 | 79,703 | 79,567 | 79,432 | 79,297 | 78,123 | 77,990 | 77,857 | 77,724 | 77,591 | 77,458 | 944,553 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 6,469 | 6,465 | 6,467 | 6,461 | 6,454 | 6,444 | 6,342 | 6,328 | 6,319 | 6,302 | 6,288 | 6,266 | 76,605 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 77,632 | 77,500 | 77,369 | 77,237 | 77,106 | 76,974 | 75,835 | 75,706 | 75,577 | 75,448 | 75,319 | 75,189 | 916,891 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 84,101 | 83,965 | 83,836 | 83,699 | 83,560 | 83,419 | 82,177 | 82,034 | 81,896 | 81,749 | 81,606 | 81,455 | 993,497 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist $4,053,254; Smith $1,729,329; Daniel $584,373, Scholz $911,255.
(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 1283 has a 7 year amortization period. PEs 1364 & 1658 are fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 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 2015 - December 2015**
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 | (1,303) | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | (1,303) | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 2,484,636 | 2,484,636 | 2,484,636 | 2,484,636 | 2,484,636 | 2,484,636 | 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) | (363,548) | (368,046) | (372,544) | (377,042) | (381,540) | (386,038) | (390,536) | (395,032) | (399,528) | (404,023) | (408,519) | (413,014) | (417,510) | |
| 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) (A) | 2,121,088 | 2,116,590 | 2,112,092 | 2,107,594 | 2,103,096 | 2,098,598 | 2,092,797 | 2,088,302 | 2,083,806 | 2,079,310 | 2,074,815 | 2,070,319 | 2,065,823 | |
| 6 | Average Net Investment | | 2,118,839 | 2,114,341 | 2,109,843 | 2,105,345 | 2,100,847 | 2,095,697 | 2,090,549 | 2,086,054 | 2,081,558 | 2,077,062 | 2,072,567 | 2,068,071 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 11,658 | 11,633 | 11,608 | 11,584 | 11,559 | 11,531 | 11,354 | 11,329 | 11,305 | 11,281 | 11,256 | 11,232 | 137,329 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 3,051 | 3,045 | 3,038 | 3,032 | 3,025 | 3,018 | 2,902 | 2,895 | 2,889 | 2,883 | 2,877 | 2,870 | 35,525 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 4,498 | 4,498 | 4,498 | 4,498 | 4,498 | 4,498 | 4,496 | 4,496 | 4,496 | 4,496 | 4,496 | 4,496 | 53,962 |
| | 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) | | 19,207 | 19,176 | 19,145 | 19,113 | 19,082 | 19,046 | 18,751 | 18,720 | 18,690 | 18,659 | 18,628 | 18,598 | 226,816 |
| | a Recoverable Costs Allocated to Energy | | 1,477 | 1,475 | 1,473 | 1,470 | 1,468 | 1,465 | 1,442 | 1,440 | 1,438 | 1,435 | 1,433 | 1,431 | 17,447 |
| | b Recoverable Costs Allocated to Demand | | 17,730 | 17,701 | 17,672 | 17,643 | 17,614 | 17,581 | 17,309 | 17,280 | 17,252 | 17,224 | 17,196 | 17,167 | 209,368 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,434 | 1,433 | 1,434 | 1,433 | 1,431 | 1,429 | 1,405 | 1,402 | 1,400 | 1,396 | 1,393 | 1,389 | 16,980 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 17,210 | 17,182 | 17,154 | 17,126 | 17,098 | 17,066 | 16,802 | 16,774 | 16,747 | 16,719 | 16,692 | 16,664 | 203,237 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 18,645 | 18,616 | 18,588 | 18,559 | 18,530 | 18,495 | 18,207 | 18,176 | 18,147 | 18,116 | 18,085 | 18,053 | 220,217 |

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) The amortizable portion of 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 1.0015 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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | |
| 3 | Less: Accumulated Depreciation (C) | (112,413) | (113,106) | (113,799) | (114,492) | (115,186) | (115,879) | (116,572) | (117,265) | (117,958) | (118,652) | (119,345) | (120,038) | (120,731) | |
| 4 | 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) | 130,560 | 129,867 | 129,173 | 128,480 | 127,787 | 127,094 | 126,401 | 125,707 | 125,014 | 124,321 | 123,628 | 122,935 | 122,241 | |
| 6 | Average Net Investment | | 130,213 | 129,520 | 128,827 | 128,134 | 127,440 | 126,747 | 126,054 | 125,361 | 124,668 | 123,974 | 123,281 | 122,588 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 716 | 713 | 709 | 705 | 701 | 697 | 685 | 681 | 677 | 673 | 670 | 666 | 8,293 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 188 | 187 | 186 | 185 | 184 | 183 | 175 | 174 | 173 | 172 | 171 | 170 | 2,145 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 8,319 |
| | 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) | | 1,597 | 1,592 | 1,588 | 1,583 | 1,578 | 1,573 | 1,553 | 1,548 | 1,543 | 1,539 | 1,534 | 1,529 | 18,756 |
| | a Recoverable Costs Allocated to Energy | | 123 | 122 | 122 | 122 | 121 | 121 | 119 | 119 | 119 | 118 | 118 | 118 | 1,443 |
| | b Recoverable Costs Allocated to Demand | | 1,474 | 1,470 | 1,465 | 1,461 | 1,457 | 1,452 | 1,433 | 1,429 | 1,425 | 1,420 | 1,416 | 1,412 | 17,314 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 119 | 119 | 119 | 119 | 118 | 118 | 116 | 116 | 116 | 115 | 115 | 114 | 1,404 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 1,431 | 1,427 | 1,422 | 1,418 | 1,414 | 1,410 | 1,391 | 1,387 | 1,383 | 1,379 | 1,374 | 1,370 | 16,807 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,550 | 1,546 | 1,541 | 1,537 | 1,532 | 1,528 | 1,508 | 1,503 | 1,499 | 1,494 | 1,489 | 1,484 | 18,211 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist $149,950; Smith $93,023.
(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 1.0015 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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | 494,283 | 494,114 | 493,945 | 493,776 | 493,607 | 493,438 | 493,269 | 493,100 | 492,931 | 492,762 | 492,593 | 492,424 | 492,255 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 494,283 | 494,114 | 493,945 | 493,776 | 493,607 | 493,438 | 493,269 | 493,100 | 492,931 | 492,762 | 492,593 | 492,424 | 492,255 | |
| 6 | Average Net Investment | | 494,199 | 494,030 | 493,861 | 493,692 | 493,523 | 493,354 | 493,185 | 493,016 | 492,847 | 492,678 | 492,509 | 492,340 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 2,719 | 2,718 | 2,717 | 2,716 | 2,715 | 2,714 | 2,678 | 2,678 | 2,677 | 2,676 | 2,675 | 2,674 | 32,358 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 712 | 711 | 711 | 711 | 711 | 710 | 685 | 684 | 684 | 684 | 684 | 683 | 8,370 |
| 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 | 169 | 169 | 169 | 169 | 169 | 169 | 2,028 |
| | 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) | | 3,600 | 3,599 | 3,597 | 3,596 | 3,595 | 3,594 | 3,532 | 3,531 | 3,530 | 3,529 | 3,527 | 3,526 | 42,756 |
| | a Recoverable Costs Allocated to Energy | | 277 | 277 | 277 | 277 | 277 | 276 | 272 | 272 | 272 | 271 | 271 | 271 | 3,289 |
| | b Recoverable Costs Allocated to Demand | | 3,323 | 3,322 | 3,321 | 3,320 | 3,318 | 3,317 | 3,260 | 3,259 | 3,258 | 3,257 | 3,256 | 3,255 | 39,467 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 269 | 269 | 269 | 270 | 270 | 270 | 265 | 264 | 264 | 264 | 264 | 263 | 3,201 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 3,226 | 3,224 | 3,223 | 3,222 | 3,221 | 3,220 | 3,165 | 3,164 | 3,163 | 3,162 | 3,161 | 3,160 | 38,311 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 3,494 | 3,493 | 3,493 | 3,492 | 3,491 | 3,490 | 3,430 | 3,428 | 3,427 | 3,426 | 3,425 | 3,423 | 41,512 |

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 1.0015 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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (188,714) | (189,825) | (190,935) | (192,046) | (193,156) | (194,267) | (195,377) | (196,488) | (197,598) | (198,709) | (199,819) | (200,930) | (202,040) | |
| 4 | 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) | 191,983 | 190,872 | 189,762 | 188,651 | 187,541 | 186,430 | 185,320 | 184,209 | 183,099 | 181,988 | 180,878 | 179,767 | 178,657 | |
| 6 | Average Net Investment | | 191,427 | 190,317 | 189,206 | 188,096 | 186,985 | 185,875 | 184,764 | 183,654 | 182,543 | 181,433 | 180,322 | 179,212 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 1,053 | 1,047 | 1,041 | 1,035 | 1,029 | 1,023 | 1,003 | 997 | 991 | 985 | 979 | 973 | 12,158 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 276 | 274 | 272 | 271 | 269 | 268 | 256 | 255 | 253 | 252 | 250 | 249 | 3,146 |
| 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) | | 2,439 | 2,432 | 2,424 | 2,416 | 2,409 | 2,401 | 2,370 | 2,363 | 2,355 | 2,348 | 2,340 | 2,333 | 28,630 |
| | a Recoverable Costs Allocated to Energy | | 188 | 187 | 186 | 186 | 185 | 185 | 182 | 182 | 181 | 181 | 180 | 179 | 2,202 |
| | b Recoverable Costs Allocated to Demand | | 2,252 | 2,245 | 2,238 | 2,230 | 2,223 | 2,216 | 2,188 | 2,181 | 2,174 | 2,167 | 2,160 | 2,153 | 26,427 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 182 | 182 | 182 | 181 | 181 | 180 | 178 | 177 | 176 | 176 | 175 | 174 | 2,143 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,186 | 2,179 | 2,172 | 2,165 | 2,158 | 2,151 | 2,124 | 2,117 | 2,110 | 2,104 | 2,097 | 2,090 | 25,653 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,368 | 2,361 | 2,354 | 2,346 | 2,339 | 2,331 | 2,302 | 2,294 | 2,287 | 2,279 | 2,272 | 2,264 | 27,797 |

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 1.0015 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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (40,893) | (41,094) | (41,295) | (41,496) | (41,697) | (41,898) | (42,099) | (42,300) | (42,501) | (42,702) | (42,903) | (43,105) | (43,306) | |
| 4 | 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) | 28,030 | 27,829 | 27,628 | 27,427 | 27,226 | 27,025 | 26,824 | 26,623 | 26,422 | 26,221 | 26,020 | 25,819 | 25,617 | |
| 6 | Average Net Investment | | 27,930 | 27,729 | 27,527 | 27,326 | 27,125 | 26,924 | 26,723 | 26,522 | 26,321 | 26,120 | 25,919 | 25,718 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 154 | 153 | 151 | 150 | 149 | 148 | 145 | 144 | 143 | 142 | 141 | 140 | 1,760 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 40 | 40 | 40 | 39 | 39 | 39 | 37 | 37 | 37 | 36 | 36 | 36 | 455 |
| 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) | | 395 | 394 | 392 | 391 | 389 | 388 | 383 | 382 | 381 | 379 | 378 | 376 | 4,628 |
| | a Recoverable Costs Allocated to Energy | | 30 | 30 | 30 | 30 | 30 | 30 | 29 | 29 | 29 | 29 | 29 | 29 | 356 |
| | b Recoverable Costs Allocated to Demand | | 365 | 363 | 362 | 361 | 359 | 358 | 354 | 353 | 351 | 350 | 349 | 347 | 4,272 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 28 | 28 | 28 | 346 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 354 | 353 | 351 | 350 | 349 | 348 | 343 | 342 | 341 | 340 | 339 | 337 | 4,147 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 383 | 382 | 381 | 379 | 378 | 377 | 372 | 371 | 369 | 368 | 367 | 365 | 4,493 |

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 1.0015 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 2015 - December 2015**
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 | 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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (69,431) | (69,727) | (70,023) | (70,319) | (70,615) | (70,911) | (71,208) | (71,504) | (71,800) | (72,096) | (72,392) | (72,688) | (72,984) | |
| 4 | 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) | 32,064 | 31,768 | 31,472 | 31,176 | 30,880 | 30,584 | 30,288 | 29,991 | 29,695 | 29,399 | 29,103 | 28,807 | 28,511 | |
| 6 | Average Net Investment | | 31,916 | 31,620 | 31,324 | 31,028 | 30,732 | 30,436 | 30,139 | 29,843 | 29,547 | 29,251 | 28,955 | 28,659 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 176 | 174 | 172 | 171 | 169 | 167 | 164 | 162 | 160 | 159 | 157 | 156 | 1,987 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 46 | 46 | 45 | 45 | 44 | 44 | 42 | 41 | 41 | 41 | 40 | 40 | 514 |
| 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) | | 518 | 516 | 514 | 511 | 509 | 507 | 502 | 500 | 498 | 496 | 494 | 491 | 6,054 |
| | a Recoverable Costs Allocated to Energy | | 40 | 40 | 40 | 39 | 39 | 39 | 39 | 38 | 38 | 38 | 38 | 38 | 466 |
| | b Recoverable Costs Allocated to Demand | | 478 | 476 | 474 | 472 | 470 | 468 | 463 | 461 | 459 | 457 | 456 | 454 | 5,588 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 39 | 39 | 38 | 38 | 38 | 38 | 38 | 37 | 37 | 37 | 37 | 37 | 453 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 464 | 462 | 460 | 458 | 456 | 455 | 449 | 448 | 446 | 444 | 442 | 440 | 5,425 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 502 | 501 | 499 | 497 | 495 | 493 | 487 | 485 | 483 | 481 | 479 | 477 | 5,878 |

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 1.0015 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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (41,051) | (41,224) | (41,398) | (41,572) | (41,745) | (41,919) | (42,093) | (42,266) | (42,440) | (42,614) | (42,787) | (42,961) | (43,135) | |
| 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) (A) | 18,492 | 18,319 | 18,145 | 17,971 | 17,798 | 17,624 | 17,450 | 17,276 | 17,103 | 16,929 | 16,755 | 16,582 | 16,408 | |
| 6 | Average Net Investment | | 18,405 | 18,232 | 18,058 | 17,884 | 17,711 | 17,537 | 17,363 | 17,190 | 17,016 | 16,842 | 16,669 | 16,495 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 101 | 100 | 99 | 98 | 97 | 96 | 94 | 93 | 92 | 91 | 91 | 90 | 1,145 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 27 | 26 | 26 | 26 | 26 | 25 | 24 | 24 | 24 | 23 | 23 | 23 | 296 |
| 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) | | 301 | 300 | 299 | 298 | 297 | 295 | 292 | 291 | 290 | 289 | 287 | 286 | 3,525 |
| | a Recoverable Costs Allocated to Energy | | 23 | 23 | 23 | 23 | 23 | 23 | 22 | 22 | 22 | 22 | 22 | 22 | 271 |
| | b Recoverable Costs Allocated to Demand | | 278 | 277 | 276 | 275 | 274 | 273 | 270 | 269 | 267 | 266 | 265 | 264 | 3,254 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 23 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 21 | 21 | 264 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 270 | 269 | 268 | 267 | 266 | 265 | 262 | 261 | 260 | 259 | 257 | 256 | 3,159 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 293 | 291 | 290 | 289 | 288 | 287 | 284 | 282 | 281 | 280 | 279 | 278 | 3,423 |

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 1.0015 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 2015 - December 2015**
Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E.s 1214 & 1413
(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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | 391,119 | |
| 3 | Less: Accumulated Depreciation (C) | (139,149) | (140,272) | (141,395) | (142,518) | (143,641) | (144,764) | (145,887) | (147,010) | (148,134) | (149,257) | (150,380) | (151,503) | (152,626) | |
| 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) | 251,970 | 250,847 | 249,724 | 248,601 | 247,478 | 246,355 | 245,232 | 244,109 | 242,985 | 241,862 | 240,739 | 239,616 | 238,493 | |
| 6 | Average Net Investment | | 251,409 | 250,286 | 249,163 | 248,039 | 246,916 | 245,793 | 244,670 | 243,547 | 242,424 | 241,301 | 240,178 | 239,055 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 1,383 | 1,377 | 1,371 | 1,365 | 1,359 | 1,352 | 1,329 | 1,323 | 1,317 | 1,311 | 1,304 | 1,298 | 16,088 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 362 | 360 | 359 | 357 | 356 | 354 | 340 | 338 | 336 | 335 | 333 | 332 | 4,162 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 1,123 | 13,477 |
| | 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) | | 2,868 | 2,861 | 2,853 | 2,845 | 2,837 | 2,829 | 2,792 | 2,784 | 2,776 | 2,769 | 2,761 | 2,753 | 33,728 |
| | a Recoverable Costs Allocated to Energy | | 221 | 220 | 219 | 219 | 218 | 218 | 215 | 214 | 214 | 213 | 212 | 212 | 2,594 |
| | b Recoverable Costs Allocated to Demand | | 2,648 | 2,641 | 2,633 | 2,626 | 2,619 | 2,612 | 2,577 | 2,570 | 2,563 | 2,556 | 2,549 | 2,541 | 31,133 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 214 | 214 | 214 | 213 | 213 | 212 | 209 | 209 | 208 | 207 | 207 | 206 | 2,525 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,570 | 2,563 | 2,556 | 2,549 | 2,542 | 2,535 | 2,501 | 2,494 | 2,488 | 2,481 | 2,474 | 2,467 | 30,221 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,784 | 2,777 | 2,770 | 2,763 | 2,755 | 2,748 | 2,711 | 2,703 | 2,696 | 2,688 | 2,680 | 2,673 | 32,746 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist $284,622; Smith $106,497.
(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 1.0015 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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | |
| 3 | Less: Accumulated Depreciation (C) | (1,671,754) | (1,679,406) | (1,687,058) | (1,694,710) | (1,702,362) | (1,710,014) | (1,717,667) | (1,725,319) | (1,732,971) | (1,740,623) | (1,748,275) | (1,755,927) | (1,763,579) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 1,110,847 | 1,103,194 | 1,095,542 | 1,087,890 | 1,080,238 | 1,072,586 | 1,064,934 | 1,057,282 | 1,049,629 | 1,041,977 | 1,034,325 | 1,026,673 | 1,019,021 | |
| 6 | Average Net Investment | | 1,107,021 | 1,099,368 | 1,091,716 | 1,084,064 | 1,076,412 | 1,068,760 | 1,061,108 | 1,053,455 | 1,045,803 | 1,038,151 | 1,030,499 | 1,022,847 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 6,091 | 6,049 | 6,007 | 5,965 | 5,922 | 5,880 | 5,763 | 5,721 | 5,680 | 5,638 | 5,597 | 5,555 | 69,867 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,594 | 1,583 | 1,572 | 1,561 | 1,550 | 1,539 | 1,473 | 1,462 | 1,452 | 1,441 | 1,430 | 1,420 | 18,077 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 91,826 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 15,337 | 15,284 | 15,231 | 15,178 | 15,125 | 15,071 | 14,888 | 14,836 | 14,783 | 14,731 | 14,679 | 14,627 | 179,770 |
| | a Recoverable Costs Allocated to Energy | | 1,180 | 1,176 | 1,172 | 1,168 | 1,163 | 1,159 | 1,145 | 1,141 | 1,137 | 1,133 | 1,129 | 1,125 | 13,828 |
| | b Recoverable Costs Allocated to Demand | | 14,157 | 14,108 | 14,059 | 14,010 | 13,961 | 13,912 | 13,743 | 13,694 | 13,646 | 13,598 | 13,550 | 13,502 | 165,942 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,145 | 1,142 | 1,141 | 1,138 | 1,134 | 1,131 | 1,116 | 1,111 | 1,108 | 1,102 | 1,098 | 1,092 | 13,458 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 13,743 | 13,695 | 13,648 | 13,600 | 13,552 | 13,505 | 13,340 | 13,293 | 13,247 | 13,200 | 13,153 | 13,106 | 161,082 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 14,888 | 14,838 | 14,788 | 14,738 | 14,687 | 14,635 | 14,456 | 14,405 | 14,354 | 14,302 | 14,251 | 14,199 | 174,540 |

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 1.0015 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 2015 - December 2015**
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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | 66,000 | 65,508 | 65,016 | 64,524 | 64,032 | 63,540 | 63,047 | 62,555 | 62,063 | 61,571 | 61,079 | 60,587 | 60,095 | |
| 4 | 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) | 244,962 | 244,470 | 243,978 | 243,486 | 242,994 | 242,501 | 242,009 | 241,517 | 241,025 | 240,533 | 240,041 | 239,549 | 239,056 | |
| 6 | Average Net Investment | | 244,716 | 244,224 | 243,732 | 243,240 | 242,748 | 242,255 | 241,763 | 241,271 | 240,779 | 240,287 | 239,795 | 239,303 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 1,346 | 1,344 | 1,341 | 1,338 | 1,336 | 1,333 | 1,313 | 1,310 | 1,308 | 1,305 | 1,302 | 1,300 | 15,876 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 352 | 352 | 351 | 350 | 350 | 349 | 336 | 335 | 334 | 334 | 333 | 332 | 4,107 |
| 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) | | 2,191 | 2,188 | 2,184 | 2,181 | 2,177 | 2,174 | 2,141 | 2,137 | 2,134 | 2,131 | 2,127 | 2,124 | 25,889 |
| | a Recoverable Costs Allocated to Energy | | 169 | 168 | 168 | 168 | 167 | 167 | 165 | 164 | 164 | 164 | 164 | 163 | 1,991 |
| | b Recoverable Costs Allocated to Demand | | 2,022 | 2,019 | 2,016 | 2,013 | 2,010 | 2,007 | 1,976 | 1,973 | 1,970 | 1,967 | 1,964 | 1,961 | 23,897 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 164 | 164 | 164 | 163 | 163 | 163 | 160 | 160 | 160 | 159 | 159 | 159 | 1,938 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 1,963 | 1,960 | 1,957 | 1,954 | 1,951 | 1,948 | 1,918 | 1,915 | 1,912 | 1,909 | 1,906 | 1,903 | 23,197 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,127 | 2,124 | 2,121 | 2,117 | 2,114 | 2,111 | 2,079 | 2,075 | 2,072 | 2,069 | 2,065 | 2,062 | 25,135 |

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 1.0015 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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (6,748,294) | (6,792,169) | (6,836,043) | (6,879,918) | (6,923,792) | (6,967,667) | (7,011,542) | (7,055,416) | (7,099,291) | (7,143,166) | (7,187,040) | (7,230,915) | (7,274,790) | |
| 4 | 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) | 8,201,830 | 8,157,955 | 8,114,081 | 8,070,206 | 8,026,332 | 7,982,457 | 7,938,582 | 7,894,708 | 7,850,833 | 7,806,958 | 7,763,084 | 7,719,209 | 7,675,334 | |
| 6 | Average Net Investment | | 8,179,893 | 8,136,018 | 8,092,143 | 8,048,269 | 8,004,394 | 7,960,520 | 7,916,645 | 7,872,770 | 7,828,896 | 7,785,021 | 7,741,146 | 7,697,272 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 45,006 | 44,764 | 44,523 | 44,282 | 44,040 | 43,799 | 42,995 | 42,757 | 42,519 | 42,280 | 42,042 | 41,804 | 520,811 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 11,779 | 11,716 | 11,653 | 11,590 | 11,526 | 11,463 | 10,988 | 10,927 | 10,867 | 10,806 | 10,745 | 10,684 | 134,743 |
| 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 | 8,996 | 8,996 | 8,996 | 8,996 | 8,996 | 8,996 | 107,952 |
| | d Property Taxes | | 24,088 | 24,088 | 24,088 | 24,088 | 24,088 | 24,088 | 24,088 | 24,088 | 24,088 | 24,088 | 24,088 | 24,088 | 289,058 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 124,748 | 124,443 | 124,138 | 123,834 | 123,529 | 123,225 | 121,946 | 121,647 | 121,348 | 121,049 | 120,750 | 120,450 | 1,471,108 |
| | a Recoverable Costs Allocated to Energy | | 9,596 | 9,573 | 9,549 | 9,526 | 9,502 | 9,479 | 9,380 | 9,357 | 9,334 | 9,311 | 9,288 | 9,265 | 113,162 |
| | b Recoverable Costs Allocated to Demand | | 115,152 | 114,871 | 114,589 | 114,308 | 114,027 | 113,746 | 112,566 | 112,290 | 112,014 | 111,737 | 111,461 | 111,185 | 1,357,946 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 9,315 | 9,302 | 9,298 | 9,282 | 9,265 | 9,244 | 9,138 | 9,111 | 9,091 | 9,059 | 9,032 | 8,994 | 110,132 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 111,779 | 111,506 | 111,234 | 110,961 | 110,688 | 110,415 | 109,269 | 109,001 | 108,733 | 108,465 | 108,197 | 107,929 | 1,318,178 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 121,094 | 120,808 | 120,532 | 120,243 | 119,952 | 119,659 | 118,408 | 118,112 | 117,824 | 117,524 | 117,229 | 116,923 | 1,428,310 |

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 1.0015 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 2015 - December 2015**
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E.s 1601, 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 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 316,287 | 27,747 | (171,573) | 16,347 | 24,557 | 25,807 | 433,000 | 433,000 | 433,000 | 433,000 | 433,000 | 433,000 | |
| | 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 Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | 134,134 | |
| 3 | Less: Accumulated Depreciation (C) | (44,052) | (44,421) | (44,790) | (45,159) | (45,528) | (45,897) | (46,266) | (46,634) | (47,003) | (47,372) | (47,741) | (48,110) | (48,479) | |
| 4 | CWIP - Non Interest Bearing | 13,726,196 | 14,042,482 | 14,070,229 | 13,898,656 | 13,915,003 | 13,939,559 | 13,965,366 | 14,398,366 | 14,831,366 | 15,264,366 | 15,697,366 | 16,130,366 | 16,563,366 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 13,816,278 | 14,132,195 | 14,159,573 | 13,987,631 | 14,003,609 | 14,027,797 | 14,053,235 | 14,485,866 | 14,918,497 | 15,351,128 | 15,783,759 | 16,216,390 | 16,649,021 | |
| 6 | Average Net Investment | | 13,974,236 | 14,145,884 | 14,073,602 | 13,995,620 | 14,015,703 | 14,040,516 | 14,269,550 | 14,702,181 | 15,134,812 | 15,567,444 | 16,000,075 | 16,432,706 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 76,886 | 77,831 | 77,433 | 77,004 | 77,114 | 77,251 | 77,498 | 79,848 | 82,197 | 84,547 | 86,896 | 89,246 | 963,751 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 20,123 | 20,370 | 20,266 | 20,154 | 20,183 | 20,218 | 19,806 | 20,407 | 21,007 | 21,608 | 22,208 | 22,809 | 249,158 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 4,426 |
| | 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) | | 97,378 | 98,570 | 98,068 | 97,526 | 97,666 | 97,838 | 97,673 | 100,623 | 103,573 | 106,523 | 109,473 | 112,423 | 1,217,335 |
| | a Recoverable Costs Allocated to Energy | | 7,491 | 7,582 | 7,544 | 7,502 | 7,513 | 7,526 | 7,513 | 7,740 | 7,967 | 8,194 | 8,421 | 8,648 | 93,641 |
| | b Recoverable Costs Allocated to Demand | | 89,887 | 90,987 | 90,524 | 90,024 | 90,153 | 90,312 | 90,160 | 92,883 | 95,606 | 98,329 | 101,052 | 103,776 | 1,123,694 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 7,271 | 7,368 | 7,345 | 7,310 | 7,325 | 7,340 | 7,319 | 7,537 | 7,760 | 7,972 | 8,189 | 8,395 | 91,130 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 87,255 | 88,323 | 87,873 | 87,388 | 87,513 | 87,667 | 87,519 | 90,163 | 92,806 | 95,450 | 98,093 | 100,736 | 1,090,786 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 94,526 | 95,690 | 95,219 | 94,698 | 94,838 | 95,007 | 94,839 | 97,699 | 100,566 | 103,422 | 106,282 | 109,131 | 1,181,916 |

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 1.0015 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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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 | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 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 2015 - December 2015**
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
(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 | | 2,888 | 4,547 | 12,329 | 4,758 | 1,061 | 188,502 | 85,889 | 122,024 | 107,809 | 41,614 | 21,827 | 21,368 | |
| | b Clearings to Plant | | 2,560 | 4,547 | 1,967 | 7,801 | 8,707 | 139,918 | 0 | 465 | 211,810 | 20,615 | 828 | 368 | |
| | c Retirements | | 20,301 | 0 | 0 | 51,625 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 10,000 | |
| | d Cost of Removal | | 361 | 352 | 19 | (34) | (25) | 2 | 0 | 0 | 0 | 0 | 0 | 12,000 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 119,192,966 | 119,175,226 | 119,179,773 | 119,181,740 | 119,137,916 | 119,146,624 | 119,286,542 | 119,286,542 | 119,287,007 | 119,498,817 | 119,519,432 | 119,520,260 | 119,510,628 | |
| 3 | Less: Accumulated Depreciation (C) | (23,523,577) | (23,890,301) | (24,277,283) | (24,664,612) | (25,000,373) | (25,388,091) | (25,775,284) | (26,162,874) | (26,550,465) | (26,938,056) | (27,326,266) | (27,714,535) | (28,080,807) | |
| 4 | CWIP - Non Interest Bearing | 4,769 | 5,097 | 5,097 | 15,459 | 12,416 | 4,769 | 53,354 | 139,243 | 260,802 | 156,801 | 177,800 | 198,799 | 219,799 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 95,674,158 | 95,290,022 | 94,907,587 | 94,532,587 | 94,149,959 | 93,763,302 | 93,564,611 | 93,262,910 | 92,997,344 | 92,717,561 | 92,370,966 | 92,004,523 | 91,649,619 | |
| 6 | Average Net Investment | | 95,482,090 | 95,098,805 | 94,720,087 | 94,341,273 | 93,956,631 | 93,663,957 | 93,413,760 | 93,130,127 | 92,857,452 | 92,544,263 | 92,187,745 | 91,827,071 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 525,342 | 523,234 | 521,150 | 519,066 | 516,949 | 515,339 | 507,330 | 505,790 | 504,309 | 502,608 | 500,672 | 498,713 | 6,140,501 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 137,494 | 136,942 | 136,397 | 135,851 | 135,298 | 134,876 | 129,658 | 129,265 | 128,886 | 128,451 | 127,957 | 127,456 | 1,588,532 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 308,305 | 308,255 | 308,268 | 308,273 | 308,264 | 308,267 | 308,661 | 308,661 | 308,662 | 309,280 | 309,340 | 309,343 | 3,703,580 |
| | b Amortization (F) | | 46,410 | 46,410 | 46,410 | 46,410 | 46,259 | 46,259 | 46,259 | 46,259 | 46,259 | 46,259 | 46,259 | 46,259 | 555,711 |
| | c Dismantlement | | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 392,040 |
| | 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) | | 1,050,222 | 1,047,510 | 1,044,894 | 1,042,269 | 1,039,440 | 1,037,411 | 1,024,579 | 1,022,644 | 1,020,786 | 1,019,269 | 1,016,898 | 1,014,441 | 12,380,363 |
| | a Recoverable Costs Allocated to Energy | | 80,786 | 80,578 | 80,376 | 80,175 | 79,957 | 79,801 | 78,814 | 78,665 | 78,522 | 78,405 | 78,223 | 78,034 | 952,336 |
| | b Recoverable Costs Allocated to Demand | | 969,435 | 966,932 | 964,518 | 962,095 | 959,483 | 957,610 | 945,765 | 943,980 | 942,264 | 940,863 | 938,675 | 936,407 | 11,428,027 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 78,421 | 78,298 | 78,265 | 78,127 | 77,956 | 77,824 | 76,778 | 76,594 | 76,476 | 76,283 | 76,065 | 75,747 | 926,834 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 941,045 | 938,615 | 936,272 | 933,919 | 931,384 | 929,566 | 918,068 | 916,335 | 914,670 | 913,310 | 911,185 | 908,984 | 11,093,353 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,019,466 | 1,016,913 | 1,014,536 | 1,012,047 | 1,009,340 | 1,007,391 | 994,846 | 992,929 | 991,146 | 989,592 | 987,250 | 984,731 | 12,020,187 |

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 have a 7-year amortization period. The amortizable portion of 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 1.0015 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 2015 - December 2015**
Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.s 1272, 1404, & 1628
(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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | |
| 3 | Less: Accumulated Depreciation (C) | (252,552) | (255,276) | (258,000) | (260,724) | (263,448) | (266,172) | (268,896) | (271,621) | (274,345) | (277,069) | (279,793) | (282,517) | (285,241) | |
| 4 | 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) | 682,178 | 679,454 | 676,730 | 674,006 | 671,282 | 668,558 | 665,834 | 663,110 | 660,386 | 657,661 | 654,937 | 652,213 | 649,489 | |
| 6 | Average Net Investment | | 680,816 | 678,092 | 675,368 | 672,644 | 669,920 | 667,196 | 664,472 | 661,748 | 659,023 | 656,299 | 653,575 | 650,851 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 3,746 | 3,731 | 3,716 | 3,701 | 3,686 | 3,671 | 3,609 | 3,594 | 3,579 | 3,564 | 3,550 | 3,535 | 43,681 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 980 | 976 | 973 | 969 | 965 | 961 | 922 | 919 | 915 | 911 | 907 | 903 | 11,300 |
| 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) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | | 7,450 | 7,431 | 7,413 | 7,394 | 7,375 | 7,356 | 7,255 | 7,237 | 7,218 | 7,199 | 7,181 | 7,162 | 87,671 |
| | a Recoverable Costs Allocated to Energy | | 573 | 572 | 570 | 569 | 567 | 566 | 558 | 557 | 555 | 554 | 552 | 551 | 6,744 |
| | b Recoverable Costs Allocated to Demand | | 6,877 | 6,860 | 6,842 | 6,825 | 6,807 | 6,790 | 6,697 | 6,680 | 6,663 | 6,646 | 6,628 | 6,611 | 80,927 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 556 | 555 | 555 | 554 | 553 | 552 | 544 | 542 | 541 | 539 | 537 | 535 | 6,563 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 6,676 | 6,659 | 6,642 | 6,625 | 6,608 | 6,591 | 6,501 | 6,484 | 6,468 | 6,451 | 6,434 | 6,418 | 78,557 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 7,232 | 7,214 | 7,197 | 7,179 | 7,161 | 7,143 | 7,045 | 7,026 | 7,008 | 6,990 | 6,971 | 6,953 | 85,120 |

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) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (22,923) | (23,106) | (23,290) | (23,473) | (23,656) | (23,840) | (24,023) | (24,206) | (24,390) | (24,573) | (24,757) | (24,940) | (25,123) | |
| 4 | 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) | 39,948 | 39,764 | 39,581 | 39,397 | 39,214 | 39,031 | 38,847 | 38,664 | 38,481 | 38,297 | 38,114 | 37,930 | 37,747 | |
| 6 | Average Net Investment | | 39,856 | 39,673 | 39,489 | 39,306 | 39,122 | 38,939 | 38,756 | 38,572 | 38,389 | 38,205 | 38,022 | 37,839 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 219 | 218 | 217 | 216 | 215 | 214 | 210 | 209 | 208 | 207 | 206 | 206 | 2,549 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 57 | 57 | 57 | 57 | 56 | 56 | 54 | 54 | 53 | 53 | 53 | 53 | 659 |
| 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) | | 460 | 459 | 458 | 456 | 455 | 454 | 448 | 446 | 445 | 444 | 443 | 441 | 5,409 |
| | a Recoverable Costs Allocated to Energy | | 35 | 35 | 35 | 35 | 35 | 35 | 34 | 34 | 34 | 34 | 34 | 34 | 416 |
| | b Recoverable Costs Allocated to Demand | | 425 | 424 | 422 | 421 | 420 | 419 | 413 | 412 | 411 | 410 | 409 | 407 | 4,993 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 33 | 33 | 33 | 33 | 33 | 405 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 412 | 411 | 410 | 409 | 408 | 407 | 401 | 400 | 399 | 398 | 397 | 396 | 4,846 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 447 | 445 | 444 | 443 | 442 | 441 | 435 | 433 | 432 | 431 | 430 | 428 | 5,251 |

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 1.0015 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 2015 - December 2015**
Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E.s 1175, 1191, 1305, 1330, 1461, 1462
(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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | 29,839,678 | |
| 3 | Less: Accumulated Depreciation (C) | (7,362,296) | (7,446,777) | (7,531,258) | (7,615,739) | (7,700,221) | (7,784,702) | (7,869,183) | (7,953,665) | (8,038,146) | (8,122,627) | (8,207,109) | (8,291,590) | (8,376,071) | |
| 4 | 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) | 22,477,382 | 22,392,901 | 22,308,420 | 22,223,938 | 22,139,457 | 22,054,976 | 21,970,495 | 21,886,013 | 21,801,532 | 21,717,051 | 21,632,569 | 21,548,088 | 21,463,607 | |
| 6 | Average Net Investment | | 22,435,142 | 22,350,660 | 22,266,179 | 22,181,698 | 22,097,217 | 22,012,735 | 21,928,254 | 21,843,773 | 21,759,291 | 21,674,810 | 21,590,329 | 21,505,847 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 123,438 | 122,973 | 122,509 | 122,044 | 121,579 | 121,114 | 119,092 | 118,634 | 118,175 | 117,716 | 117,257 | 116,798 | 1,441,328 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 32,307 | 32,185 | 32,063 | 31,942 | 31,820 | 31,698 | 30,436 | 30,319 | 30,202 | 30,085 | 29,967 | 29,850 | 372,874 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 84,481 | 1,013,776 |
| | 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) | | 240,226 | 239,640 | 239,053 | 238,467 | 237,880 | 237,294 | 234,010 | 233,434 | 232,858 | 232,282 | 231,706 | 231,130 | 2,827,978 |
| | a Recoverable Costs Allocated to Energy | | 18,479 | 18,434 | 18,389 | 18,344 | 18,298 | 18,253 | 18,001 | 17,956 | 17,912 | 17,868 | 17,824 | 17,779 | 217,537 |
| | b Recoverable Costs Allocated to Demand | | 221,747 | 221,206 | 220,664 | 220,123 | 219,582 | 219,040 | 216,009 | 215,478 | 214,946 | 214,414 | 213,882 | 213,350 | 2,610,442 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 17,938 | 17,912 | 17,906 | 17,875 | 17,841 | 17,801 | 17,536 | 17,484 | 17,445 | 17,384 | 17,332 | 17,258 | 211,712 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 215,253 | 214,728 | 214,202 | 213,677 | 213,151 | 212,626 | 209,683 | 209,167 | 208,651 | 208,135 | 207,619 | 207,102 | 2,533,994 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 233,191 | 232,640 | 232,108 | 231,552 | 230,992 | 230,427 | 227,219 | 226,651 | 226,096 | 225,519 | 224,950 | 224,361 | 2,745,706 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist $13,997,696; Smith $15,715,201; Scholz $126,781.
(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 1.0015 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 2015 - December 2015**
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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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 | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 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 2015 - December 2015**
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 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 2,758 | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 20,026,649 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | |
| 3 | Less: Accumulated Depreciation (C) | (3,272,969) | (3,328,629) | (3,387,039) | (3,445,448) | (3,503,858) | (3,562,268) | (3,620,677) | (3,679,087) | (3,737,497) | (3,795,906) | (3,854,316) | (3,912,726) | (3,971,136) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 16,753,680 | 16,695,262 | 16,636,852 | 16,578,443 | 16,520,033 | 16,461,623 | 16,403,214 | 16,344,804 | 16,286,394 | 16,227,985 | 16,169,575 | 16,111,165 | 16,052,755 | |
| 6 | Average Net Investment | | 16,724,471 | 16,666,057 | 16,607,648 | 16,549,238 | 16,490,828 | 16,432,419 | 16,374,009 | 16,315,599 | 16,257,189 | 16,198,780 | 16,140,370 | 16,081,960 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 92,018 | 91,697 | 91,375 | 91,054 | 90,733 | 90,411 | 88,927 | 88,610 | 88,293 | 87,976 | 87,658 | 87,341 | 1,076,093 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 24,083 | 23,999 | 23,915 | 23,831 | 23,747 | 23,663 | 22,727 | 22,646 | 22,565 | 22,484 | 22,403 | 22,322 | 278,384 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 58,418 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 700,924 |
| | 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) | | 174,519 | 174,105 | 173,700 | 173,295 | 172,889 | 172,484 | 170,064 | 169,666 | 169,267 | 168,869 | 168,471 | 168,073 | 2,055,402 |
| | a Recoverable Costs Allocated to Energy | | 13,425 | 13,393 | 13,362 | 13,330 | 13,299 | 13,268 | 13,082 | 13,051 | 13,021 | 12,990 | 12,959 | 12,929 | 158,108 |
| | b Recoverable Costs Allocated to Demand | | 161,094 | 160,713 | 160,338 | 159,964 | 159,590 | 159,216 | 156,982 | 156,615 | 156,247 | 155,879 | 155,512 | 155,144 | 1,897,294 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 13,031 | 13,014 | 13,010 | 12,990 | 12,966 | 12,939 | 12,744 | 12,708 | 12,681 | 12,638 | 12,602 | 12,550 | 153,874 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 156,377 | 156,006 | 155,643 | 155,280 | 154,916 | 154,553 | 152,385 | 152,028 | 151,671 | 151,314 | 150,957 | 150,600 | 1,841,731 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 169,408 | 169,020 | 168,653 | 168,269 | 167,883 | 167,492 | 165,129 | 164,736 | 164,352 | 163,952 | 163,559 | 163,150 | 1,995,605 |

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 1.0015 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 2015 - December 2015**
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 | 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 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (1,753,215) | (1,771,164) | (1,789,113) | (1,807,062) | (1,825,010) | (1,842,959) | (1,860,908) | (1,878,856) | (1,896,805) | (1,914,754) | (1,932,703) | (1,950,651) | (1,968,600) | |
| 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) (A) | 4,399,925 | 4,381,976 | 4,364,027 | 4,346,079 | 4,328,130 | 4,310,181 | 4,292,232 | 4,274,284 | 4,256,335 | 4,238,386 | 4,220,438 | 4,202,489 | 4,184,540 | |
| 6 | Average Net Investment | | 4,390,950 | 4,373,002 | 4,355,053 | 4,337,104 | 4,319,156 | 4,301,207 | 4,283,258 | 4,265,309 | 4,247,361 | 4,229,412 | 4,211,463 | 4,193,515 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 24,159 | 24,060 | 23,962 | 23,863 | 23,764 | 23,665 | 23,262 | 23,165 | 23,067 | 22,970 | 22,872 | 22,775 | 281,585 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 6,323 | 6,297 | 6,271 | 6,245 | 6,220 | 6,194 | 5,945 | 5,920 | 5,895 | 5,870 | 5,846 | 5,821 | 72,847 |
| 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) | | 48,431 | 48,306 | 48,181 | 48,057 | 47,932 | 47,808 | 47,156 | 47,034 | 46,911 | 46,789 | 46,667 | 46,544 | 569,817 |
| | a Recoverable Costs Allocated to Energy | | 3,725 | 3,716 | 3,706 | 3,697 | 3,687 | 3,678 | 3,627 | 3,618 | 3,609 | 3,599 | 3,590 | 3,580 | 43,832 |
| | b Recoverable Costs Allocated to Demand | | 44,705 | 44,590 | 44,475 | 44,360 | 44,245 | 44,130 | 43,529 | 43,416 | 43,303 | 43,190 | 43,077 | 42,964 | 525,985 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 3,616 | 3,611 | 3,609 | 3,602 | 3,595 | 3,586 | 3,534 | 3,523 | 3,515 | 3,502 | 3,491 | 3,475 | 42,658 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 43,396 | 43,284 | 43,173 | 43,061 | 42,949 | 42,838 | 42,254 | 42,144 | 42,035 | 41,925 | 41,815 | 41,706 | 510,581 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 47,012 | 46,895 | 46,782 | 46,663 | 46,544 | 46,424 | 45,788 | 45,667 | 45,549 | 45,427 | 45,306 | 45,181 | 553,239 |

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 1.0015 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 2015 - December 2015**
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, 1468, 1469, 1505, 1508, 1512, 1513, 1517, 1551, 1552, 1646, 1647, 1684, 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 | | 670,160 | 477,715 | 855,365 | 971,366 | 416,691 | 1,041,591 | 1,113,681 | 1,173,762 | 1,444,731 | 266,195,857 | 86,050,617 | 2,120,695 | |
| | b Clearings to Plant | | (734) | 61,959 | 63,158 | 305,903 | 52,647 | 1,496,102 | 93,898 | 470 | 95,872 | 264,386,283 | 85,559,201 | 10,947,481 | |
| | c Retirements | | 13,849 | 0 | 472,188 | 0 | 13,849 | (415,602) | 0 | 0 | 0 | 0 | 0 | 52,000 | |
| | d Cost of Removal | | (321) | (0) | 1 | 300 | (4) | 859 | 0 | 0 | 0 | 0 | 10,000 | 0 | |
| | e Salvage | | 0 | 24,129 | 13,968 | 0 | (24,129) | 7,000 | 0 | 0 | 0 | 0 | 0 | 20,000 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 800,958,016 | 800,943,433 | 801,005,393 | 800,596,363 | 800,902,266 | 800,941,064 | 802,852,768 | 802,946,666 | 802,947,136 | 803,043,008 | 1,067,429,291 | 1,152,988,492 | 1,163,883,973 | |
| 3 | Less: Accumulated Depreciation (C) | (144,922,714) | (147,565,884) | (150,246,668) | (152,445,282) | (155,100,469) | (157,718,649) | (160,796,518) | (163,458,154) | (166,119,998) | (168,781,843) | (171,443,969) | (174,712,941) | (178,159,530) | |
| 4 | CWIP - Non Interest Bearing | 3,004,902 | 3,675,797 | 4,091,553 | 4,883,760 | 5,549,223 | 5,913,267 | 5,458,756 | 6,478,539 | 7,651,831 | 9,000,690 | 10,810,264 | 11,301,680 | 2,474,894 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 659,040,204 | 657,053,346 | 654,850,277 | 653,034,840 | 651,351,020 | 649,135,683 | 647,515,007 | 645,967,051 | 644,478,969 | 643,261,855 | 906,795,587 | 989,577,231 | 988,199,337 | |
| 6 | Average Net Investment | | 658,046,775 | 655,951,811 | 653,942,558 | 652,192,930 | 650,243,351 | 648,325,345 | 646,741,029 | 645,223,010 | 643,870,412 | 775,028,721 | 948,186,409 | 988,888,284 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 3,620,573 | 3,609,047 | 3,597,992 | 3,588,366 | 3,577,639 | 3,567,086 | 3,512,451 | 3,504,206 | 3,496,860 | 4,209,181 | 5,149,600 | 5,370,652 | 46,803,653 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 947,587 | 944,571 | 941,677 | 939,158 | 936,350 | 933,588 | 897,677 | 895,570 | 893,692 | 1,075,740 | 1,316,083 | 1,372,577 | 12,094,270 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 2,321,513 | 2,321,471 | 2,321,577 | 2,320,304 | 2,320,971 | 2,320,945 | 2,326,455 | 2,326,662 | 2,326,664 | 2,326,943 | 2,943,791 | 3,143,408 | 29,320,705 |
| | b Amortization (F) | | 20,287 | 20,287 | 20,361 | 20,286 | 20,285 | 20,284 | 20,285 | 20,285 | 20,285 | 20,285 | 20,285 | 20,285 | 243,498 |
| | c Dismantlement | | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 3,778,764 |
| | d Property Taxes | | 235,945 | 235,945 | 235,945 | 235,945 | 235,945 | 235,945 | 235,945 | 235,945 | 235,945 | 235,945 | 235,945 | 235,945 | 2,831,342 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 7,460,803 | 7,446,217 | 7,432,450 | 7,418,956 | 7,406,088 | 7,392,746 | 7,307,709 | 7,297,565 | 7,288,343 | 8,182,991 | 9,980,601 | 10,457,764 | 95,072,232 |
| | a Recoverable Costs Allocated to Energy | | 573,908 | 572,786 | 571,727 | 570,689 | 569,699 | 568,673 | 562,131 | 561,351 | 560,642 | 629,461 | 767,739 | 804,443 | 7,313,249 |
| | b Recoverable Costs Allocated to Demand | | 6,886,895 | 6,873,431 | 6,860,723 | 6,848,267 | 6,836,389 | 6,824,073 | 6,745,577 | 6,736,214 | 6,727,701 | 7,553,530 | 9,212,862 | 9,653,320 | 87,758,983 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 557,105 | 556,579 | 556,706 | 556,114 | 555,445 | 554,588 | 547,612 | 546,576 | 546,031 | 612,419 | 746,557 | 780,872 | 7,116,603 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 6,685,210 | 6,672,140 | 6,659,804 | 6,647,712 | 6,636,182 | 6,624,227 | 6,548,030 | 6,538,941 | 6,530,678 | 7,332,322 | 8,943,060 | 9,370,619 | 85,188,926 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 7,242,315 | 7,228,719 | 7,216,510 | 7,203,827 | 7,191,628 | 7,178,815 | 7,095,642 | 7,085,517 | 7,076,709 | 7,944,741 | 9,689,617 | 10,151,491 | 92,305,529 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $781,247,403; Smith $12,931,385; Daniel $6,772,129, Scholz $7,099. Ending Balances: Crist $783,351,695; Smith $12,931,385; Daniel $367,593,793, Scholz $7,099.
(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 1222, 1233, 1279 and 1909 have a 7 year amortization period. PE 1168 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 1.0015 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 2015 - December 2015**
Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.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 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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 | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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) Fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 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 2015 - December 2015**
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 | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 line loss multiplier.
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 7E.
(E) Line 8 is reported on Schedule 5E.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
**January 2015 - December 2015**
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 | 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 Annual NOx 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 | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 line loss multiplier.
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 7E.
(E) Line 8 is reported on Schedule 5E.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
**January 2015 - December 2015**
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 | 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 Seasonal NOx 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 | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 line loss multiplier.
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 7E.
(E) Line 8 is reported on Schedule 5E.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
**January 2015 - December 2015**
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 | 90 | 37 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Working Capital | | | | | | | | | | | | | | |
| | a FERC 158.1 Allowance Inventory | 6,632,174 | 6,606,910 | 6,556,057 | 6,517,215 | 6,496,539 | 6,464,098 | 6,435,107 | 6,389,209 | 6,340,659 | 6,306,761 | 6,278,989 | 6,247,407 | 6,234,958 | |
| | 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 | (118,005) | (108,803) | (99,601) | (90,286) | (81,167) | (71,990) | (62,777) | (53,575) | (44,943) | (35,742) | (26,540) | (17,339) | (8,137) | |
| 3 | Total Working Capital Balance | 6,514,169 | 6,498,107 | 6,456,456 | 6,426,929 | 6,415,372 | 6,392,108 | 6,372,330 | 6,335,633 | 6,295,716 | 6,271,019 | 6,252,448 | 6,230,068 | 6,226,821 | |
| 4 | Average Net Working Capital Balance | | 6,506,138 | 6,477,281 | 6,441,692 | 6,421,151 | 6,403,740 | 6,382,219 | 6,353,982 | 6,315,675 | 6,283,368 | 6,261,734 | 6,241,258 | 6,228,445 | |
| 5 | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a Equity Component (Line 4 x Equity Component x 1/12) (A) | | 35,797 | 35,638 | 35,442 | 35,329 | 35,233 | 35,115 | 34,508 | 34,300 | 34,125 | 34,007 | 33,896 | 33,827 | 417,219 |
| | b Debt Component (Line 4 x Debt Component x 1/12) | | 9,369 | 9,327 | 9,276 | 9,246 | 9,221 | 9,190 | 8,819 | 8,766 | 8,721 | 8,691 | 8,663 | 8,645 | 107,936 |
| 6 | Total Return Component (D) | | 45,166 | 44,965 | 44,718 | 44,576 | 44,455 | 44,305 | 43,328 | 43,067 | 42,846 | 42,699 | 42,559 | 42,472 | 525,155 |
| 7 | Expenses | | | | | | | | | | | | | | |
| | a Gains | | (9,202) | (9,202) | (9,315) | (9,209) | (9,213) | (9,213) | (9,202) | (9,202) | (9,202) | (9,202) | (9,202) | (9,202) | (110,563) |
| | b Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c SO2 Allowance Expense | | 25,264 | 50,853 | 38,842 | 20,676 | 32,441 | 28,991 | 45,898 | 48,550 | 33,898 | 27,772 | 31,582 | 12,449 | 397,216 |
| 8 | Net Expenses (E) | | 16,063 | 41,651 | 29,527 | 11,467 | 23,228 | 19,778 | 36,697 | 39,348 | 24,696 | 18,571 | 22,380 | 3,247 | 286,653 |
| 9 | Total System Recoverable Expenses (Lines 6 + 8) | | 61,228 | 86,616 | 74,245 | 56,043 | 67,683 | 64,083 | 80,024 | 82,415 | 67,542 | 61,270 | 64,939 | 45,719 | 811,808 |
| | a Recoverable Costs Allocated to Energy | | 19,537 | 45,110 | 32,967 | 14,896 | 26,648 | 23,186 | 40,029 | 42,661 | 27,992 | 21,855 | 25,654 | 6,514 | 327,049 |
| | b Recoverable Costs Allocated to Demand | | 41,691 | 41,506 | 41,278 | 41,147 | 41,035 | 40,897 | 39,995 | 39,754 | 39,550 | 39,414 | 39,285 | 39,205 | 484,759 |
| 10 | Energy Jurisdictional Factor | | 0.9692682 | 0.9702488 | 0.9722685 | 0.9730022 | 0.9735201 | 0.9737713 | 0.9727113 | 0.9722209 | 0.9724802 | 0.9714685 | 0.9709536 | 0.9692443 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (B) | | 18,965 | 43,833 | 32,101 | 14,516 | 25,981 | 22,612 | 38,996 | 41,538 | 27,262 | 21,264 | 24,946 | 6,324 | 318,337 |
| 13 | Retail Demand-Related Recoverable Costs (C) | | 40,470 | 40,291 | 40,070 | 39,942 | 39,833 | 39,700 | 38,824 | 38,590 | 38,392 | 38,260 | 38,135 | 38,057 | 470,562 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 59,435 | 84,124 | 72,170 | 54,457 | 65,815 | 62,311 | 77,819 | 80,127 | 65,655 | 59,524 | 63,081 | 44,380 | 788,899 |

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x 1.0015 line loss multiplier.
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 7E.
(E) Line 8 is reported on Schedule 5E.

**Schedule 9E**
Page 1 of 2

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
**January 2015 - June 2015**

**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 | 680,813 | 36.0280 | 4.70 | 1.6932 | 1.6932 | |
| 2 | Short-Term Debt | 24,978 | 1.3218 | 0.35 | 0.0046 | 0.0046 | |
| 3 | Preferred Stock | 79,703 | 4.2178 | 6.15 | 0.2596 | 0.4226 | |
| 4 | Common Stock | 698,675 | 36.9732 | 10.25 | 3.7898 | 6.1698 | |
| 5 | Customer Deposits | 21,600 | 1.1430 | 2.41 | 0.0275 | 0.0275 | |
| 6 | Deferred Taxes | 381,708 | 20.1996 | | | | |
| 7 | Investment Tax Credit | 2,202 | 0.1165 | 7.44 | 0.0087 | 0.0125 | |
| 8 | Total | 1,889,680 | 100.0000 | | 5.7834 | 8.3302 | 0.6942 |
| | ITC Component: | | | | | | |
| 9 | Debt | 680,813 | 46.6569 | 4.70 | 2.1928 | 0.0026 | |
| 10 | Equity-Preferred | 79,703 | 5.4621 | 6.15 | 0.3361 | 0.0006 | |
| 11 | -Common | 698,675 | 47.8810 | 10.25 | 4.9078 | 0.0093 | |
| 12 | | 1,459,192 | 100.0000 | | 7.4367 | 0.0125 | |
| | Breakdown of Revenue Requirement Rate of Return between Debt and Equity: | | | | | | |
| 13 | Total Debt Component (Lines 1, 2, 5, and 9) | | | | | 1.7279 | 0.1440 |
| 14 | Total Equity Component (Lines 3, 4, 10, and 11) | | | | | 6.6023 | 0.5502 |
| 15 | Total Revenue Requirement Rate of Return | | | | | 8.3302 | 0.6942 |

Column:
(1) Based on the May 2014 Surveillance Report, Schedule 4.
(2) Column (1) / Total Column (1)
(3) Based on the May 2014 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 Current Period Estimated True-up Amount
**July 2015 - December 2015**

**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 | 710,379 | 36.4100 | 4.49 | 1.6348 | 1.6348 | |
| 2 | Short-Term Debt | 21,331 | 1.0933 | 0.27 | 0.0030 | 0.0030 | |
| 3 | Preferred Stock | 79,362 | 4.0676 | 6.14 | 0.2498 | 0.4067 | |
| 4 | Common Stock | 713,646 | 36.5774 | 10.25 | 3.7492 | 6.1037 | |
| 5 | Customer Deposits | 21,109 | 1.0819 | 2.40 | 0.0260 | 0.0260 | |
| 6 | Deferred Taxes | 403,636 | 20.6881 | | | | |
| 7 | Investment Tax Credit | 1,592 | 0.0816 | 7.31 | 0.0060 | 0.0086 | |
| 8 | Total | 1,951,055 | 100.0000 | | 5.6688 | 8.1828 | 0.6819 |
| | ITC Component: | | | | | | |
| 9 | Debt | 710,379 | 47.2519 | 4.49 | 2.1216 | 0.0017 | |
| 10 | Equity-Preferred | 79,362 | 5.2789 | 6.14 | 0.3241 | 0.0004 | |
| 11 | -Common | 713,646 | 47.4692 | 10.25 | 4.8656 | 0.0065 | |
| 12 | | 1,503,387 | 100.0000 | | 7.3113 | 0.0086 | |
| | Breakdown of Revenue Requirement Rate of Return between Debt and Equity: | | | | | | |
| 13 | Total Debt Component (Lines 1, 2, 5, and 9) | | | | | 1.6655 | 0.1388 |
| 14 | Total Equity Component (Lines 3, 4, 10, and 11) | | | | | 6.5173 | 0.5431 |
| 15 | Total Revenue Requirement Rate of Return | | | | | 8.1828 | 0.6819 |

Column:
(1) Based on the May 2015 Surveillance Report, Schedule 4.
(2) Column (1) / Total Column (1)
(3) Based on the May 2015 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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 27
PARTY: GULF POWER COMPANY (GULF) – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-3



**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
**Total Jurisdictional Amount to be Recovered**

For the Projected Period
**January 2016 - December 2016**

| 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) | 29,090,992 | 19,003,213 | 48,094,205 |
| | b Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9) | 11,529,442 | 138,141,755 | 149,671,197 |
| | c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b) | 40,620,434 | 157,144,968 | 197,765,402 |
| 2 | True-Up for Estimated Over/(Under) Recovery for the period January 2015 - December 2015 (Schedule 1E, Line 3) | (339,826) | (1,359,302) | (1,699,128) |
| 3 | Final True-Up for the period January 2014 - December 2014 (Schedule 1A, Line 3) | (182,557) | (730,226) | (912,783) |
| 4 | Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2016 - December 2016 (Line 1c - Line 2 - Line 3) | 41,142,816 | 159,234,496 | 200,377,313 |
| 5 | Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier) | 41,172,439 | 159,349,145 | 200,521,584 |

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.

Schedule 2P

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
**Calculation of the Projected Period Amount**
**January 2016 - December 2016**

**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 | 0 | 212,000 | 169,677 | 0 | 0 | 0 | 0 | 178,675 | 0 | 0 | 0 | 0 | 560,352 | 0 | 560,352 |
| . 3 | Title V | 10,513 | 10,513 | 10,817 | 16,014 | 10,817 | 11,717 | 11,317 | 11,317 | 17,014 | 11,817 | 11,317 | 11,313 | 144,489 | 0 | 144,489 |
| . 4 | Asbestos Fees | 1,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,000 | 1,000 | 0 |
| . 5 | Emission Monitoring | 58,452 | 107,616 | 59,117 | 72,720 | 63,289 | 61,261 | 61,761 | 63,289 | 74,748 | 65,317 | 63,289 | 65,361 | 816,217 | 0 | 816,217 |
| . 6 | General Water Quality | 143,370 | 142,680 | 188,060 | 169,847 | 177,964 | 164,267 | 164,064 | 168,868 | 193,606 | 178,837 | 161,511 | 156,603 | 2,009,676 | 2,009,676 | 0 |
| . 7 | Groundwater Contamination Investigation | 275,818 | 280,501 | 282,564 | 304,615 | 292,179 | 280,840 | 280,346 | 282,319 | 304,369 | 292,424 | 282,564 | 279,119 | 3,437,656 | 3,437,656 | 0 |
| . 8 | State NPDES Administration | 34,667 | 167 | 167 | 167 | 167 | 167 | 167 | 167 | 167 | 167 | 167 | 163 | 36,500 | 36,500 | 0 |
| . 9 | Lead and Copper Rule | 1,414 | 1,414 | 1,414 | 1,414 | 1,414 | 1,414 | 1,414 | 1,414 | 1,414 | 1,414 | 1,414 | 1,420 | 16,974 | 16,974 | 0 |
| . 10 | Env Auditing/Assessment | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4,500 | 4,500 | 0 | 9,000 | 9,000 | 0 |
| . 11 | General Solid & Hazardous Waste | 58,046 | 57,046 | 64,249 | 71,814 | 66,249 | 65,249 | 59,749 | 60,749 | 78,314 | 61,749 | 66,249 | 61,769 | 771,232 | 771,232 | 0 |
| . 12 | Above Ground Storage Tanks | 35,419 | 34,937 | 10,400 | 7,168 | 7,263 | 10,647 | 5,810 | 6,243 | 6,613 | 16,685 | 16,231 | 6,762 | 164,181 | 164,181 | 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 | 5,096 | 4,368 | 5,096 | 5,824 | 6,552 | 5,824 | 5,824 | 6,552 | 6,552 | 7,280 | 6,552 | 7,280 | 72,800 | 0 | 72,800 |
| . 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 | 74,907 | 60,980 | 68,752 | 71,623 | 84,536 | 91,331 | 94,018 | 96,666 | 64,233 | 94,984 | 68,161 | 82,197 | 952,387 | 0 | 952,387 |
| . 20 | Air Quality Compliance Program | 2,104,526 | 1,812,554 | 1,662,539 | 1,703,498 | 2,293,101 | 2,474,066 | 2,812,491 | 2,991,807 | 2,027,466 | 2,972,632 | 2,173,933 | 2,117,820 | 27,146,432 | 0 | 27,146,432 |
| . 21 | MACT ICR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 22 | Crist Water Conservation | 16,510 | 17,480 | 113,910 | 19,840 | 20,770 | 119,340 | 26,740 | 27,270 | 121,670 | 29,300 | 28,270 | 29,200 | 570,300 | 570,300 | 0 |
| . 23 | Coal Combustion Residual | 230,000 | 30,000 | 530,000 | 530,000 | 1,030,000 | 1,030,000 | 1,530,000 | 1,530,000 | 1,530,000 | 1,530,000 | 1,530,000 | 1,530,000 | 12,560,000 | 12,560,000 | 0 |
| . 24 | Mercury Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 25 | Annual NOx Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 26 | Seasonal NOx Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 27 | SO2 Allowances | 15,310 | 11,377 | 11,199 | 15,165 | 24,453 | 17,354 | 30,208 | 29,552 | 16,943 | 25,686 | 13,043 | 15,921 | 226,209 | 0 | 226,209 |
| 2 | Total of O & M Activities | 3,065,049 | 2,783,634 | 3,177,961 | 2,989,709 | 4,078,753 | 4,333,476 | 5,083,908 | 5,454,887 | 4,443,109 | 5,292,791 | 4,427,200 | 4,364,928 | 49,495,405 | 19,576,519 | 29,918,886 |
| 3 | Recoverable Costs Allocated to Energy | 2,268,803 | 2,219,407 | 1,987,197 | 1,884,844 | 2,482,748 | 2,661,553 | 3,015,618 | 3,377,858 | 2,206,956 | 3,177,716 | 2,336,295 | 2,299,891 | 29,918,886 | | |
| 4 | Recoverable Costs Allocated to Demand | 796,245 | 564,226 | 1,190,764 | 1,104,865 | 1,596,005 | 1,671,923 | 2,068,289 | 2,077,029 | 2,236,153 | 2,115,075 | 2,090,905 | 2,065,036 | 19,576,519 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | 2,200,050 | 2,154,852 | 1,930,920 | 1,833,198 | 2,416,042 | 2,591,968 | 2,936,906 | 3,288,178 | 2,148,930 | 3,090,971 | 2,268,899 | 2,230,077 | 29,090,992 | | |
| 8 | Jurisdictional Demand Recoverable Costs (B) | 772,927 | 547,703 | 1,155,892 | 1,072,509 | 1,549,266 | 1,622,961 | 2,007,719 | 2,016,203 | 2,170,667 | 2,053,135 | 2,029,672 | 2,004,561 | 19,003,213 | | |
| 9 | Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8) | 2,972,977 | 2,702,555 | 3,086,812 | 2,905,707 | 3,965,308 | 4,214,929 | 4,944,625 | 5,304,381 | 4,319,596 | 5,144,106 | 4,298,572 | 4,234,638 | 48,094,205 | | |

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
**Calculation of the Projected Period Amount**
**January 2016 - December 2016**

**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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 2 | Crist 5, 6 & 7 Precipitator Projects | 353,721 | 353,011 | 352,302 | 351,593 | 350,884 | 350,175 | 349,466 | 348,756 | 348,047 | 347,338 | 346,629 | 345,920 | 4,197,842 | 3,874,931 | 322,911 |
| . 3 | Crist 7 Flue Gas Conditioning | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 118,609 | 109,485 | 9,124 |
| . 4 | Low NOx Burners, Crist 6 & 7 | 145,851 | 145,603 | 145,355 | 145,107 | 144,860 | 144,612 | 144,364 | 144,116 | 143,869 | 143,621 | 143,373 | 143,125 | 1,733,856 | 1,600,482 | 133,374 |
| . 5 | CEMS - Plants Crist, Scholz, Smith, & Daniel | 73,763 | 77,323 | 80,601 | 83,597 | 81,853 | 84,882 | 86,781 | 95,944 | 95,833 | 95,760 | 95,688 | 95,616 | 1,047,640 | 967,052 | 80,588 |
| . 6 | Substation Contamination Remediation | 18,567 | 18,537 | 18,506 | 18,475 | 18,445 | 18,414 | 18,383 | 18,353 | 18,322 | 18,291 | 18,261 | 18,230 | 220,783 | 203,799 | 16,983 |
| . 7 | Raw Water Well Flowmeters - Plants Crist & Smith | 1,524 | 1,520 | 1,515 | 1,510 | 1,506 | 1,501 | 1,496 | 1,491 | 1,487 | 1,482 | 1,477 | 1,472 | 17,981 | 16,598 | 1,383 |
| . 8 | Crist Cooling Tower Cell | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 40,280 | 37,182 | 3,098 |
| . 9 | Crist Dechlorination System | 2,325 | 2,317 | 2,310 | 2,302 | 2,295 | 2,287 | 2,280 | 2,272 | 2,264 | 2,257 | 2,249 | 2,242 | 27,400 | 25,292 | 2,108 |
| . 10 | Crist Diesel Fuel Oil Remediation | 375 | 374 | 372 | 371 | 370 | 368 | 367 | 365 | 364 | 363 | 361 | 360 | 4,410 | 4,071 | 339 |
| . 11 | Crist Bulk Tanker Unload Sec Contain Struc | 489 | 487 | 485 | 483 | 481 | 479 | 477 | 475 | 473 | 471 | 469 | 467 | 5,740 | 5,299 | 442 |
| . 12 | Crist IWW Sampling System | 285 | 284 | 283 | 281 | 280 | 279 | 278 | 277 | 276 | 274 | 273 | 272 | 3,342 | 3,085 | 257 |
| . 13 | Sodium Injection System | 2,746 | 2,738 | 2,730 | 2,723 | 2,423 | 2,417 | 2,412 | 2,406 | 2,400 | 2,395 | 2,389 | 2,383 | 30,162 | 27,842 | 2,320 |
| . 14 | Smith Stormwater Collection System | 14,575 | 14,523 | 14,470 | 14,418 | 14,366 | 14,314 | 14,262 | 14,210 | 14,157 | 14,105 | 14,053 | 14,001 | 171,453 | 158,265 | 13,189 |
| . 15 | Smith Waste Water Treatment Facility | 2,121 | 2,117 | 2,114 | 2,111 | 2,107 | 2,104 | 2,100 | 2,097 | 2,094 | 2,090 | 2,087 | 2,084 | 25,226 | 23,285 | 1,940 |
| . 16 | Daniel Ash Management Project | 117,854 | 117,555 | 117,256 | 116,957 | 116,658 | 116,358 | 116,059 | 115,760 | 115,461 | 115,162 | 114,863 | 114,563 | 1,394,507 | 1,287,237 | 107,270 |
| . 17 | Smith Water Conservation | 115,059 | 116,219 | 116,216 | 116,214 | 116,211 | 116,209 | 116,206 | 116,204 | 116,201 | 116,199 | 116,196 | 116,194 | 1,393,327 | 1,286,148 | 107,179 |
| . 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 | 974,898 | 973,334 | 971,950 | 969,794 | 967,920 | 966,046 | 963,652 | 961,258 | 959,123 | 958,076 | 957,694 | 956,485 | 11,580,228 | 10,689,442 | 890,787 |
| . 20 | SPCC Compliance | 7,144 | 7,125 | 7,107 | 7,088 | 7,069 | 7,051 | 7,032 | 7,014 | 6,995 | 6,977 | 6,958 | 6,939 | 84,498 | 77,999 | 6,500 |
| . 21 | Crist Common FTIR Monitor | 440 | 439 | 438 | 436 | 435 | 434 | 433 | 431 | 430 | 429 | 428 | 426 | 5,199 | 4,799 | 400 |
| . 22 | Precipitator Upgrades for CAM Compliance | 229,544 | 228,971 | 228,398 | 227,825 | 184,182 | 183,904 | 183,625 | 183,347 | 183,068 | 182,790 | 182,511 | 182,233 | 2,380,396 | 2,197,289 | 183,107 |
| . 23 | Plant Groundwater Investigation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 24 | Crist Water Conservation | 167,674 | 167,276 | 166,878 | 166,479 | 166,081 | 165,683 | 165,285 | 164,886 | 164,488 | 164,090 | 163,691 | 163,293 | 1,985,804 | 1,833,050 | 152,754 |
| . 25 | Plant NPDES Permit Compliance Projects | 46,422 | 46,300 | 46,177 | 46,055 | 45,932 | 45,810 | 45,688 | 45,565 | 45,443 | 45,320 | 45,198 | 45,076 | 548,985 | 506,755 | 42,230 |
| . 26 | Air Quality Compliance Program | 10,595,481 | 10,597,092 | 10,586,554 | 10,575,548 | 10,529,369 | 10,518,267 | 10,503,457 | 10,492,424 | 10,472,678 | 10,456,302 | 10,441,223 | 10,419,859 | 126,188,252 | 116,481,463 | 9,706,789 |
| . 27 | General Water Quality | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 28 | Coal Combustion Residual | 8,906 | 14,147 | 19,729 | 25,585 | 30,825 | 36,064 | 41,303 | 46,542 | 51,781 | 57,021 | 62,260 | 67,550 | 461,713 | 426,196 | 35,516 |
| . 29 | Mercury Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 30 | Annual NOx Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 31 | Seasonal NOx Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| . 32 | SO2 Allowances | 42,408 | 42,318 | 42,241 | 42,151 | 42,016 | 41,873 | 41,711 | 41,507 | 41,349 | 41,203 | 41,071 | 40,972 | 500,819 | 462,295 | 38,525 |
| 2 | Total Investment Projects - Recoverable Costs | 12,935,413 | 12,942,849 | 12,937,226 | 12,930,344 | 12,839,807 | 12,832,770 | 12,820,355 | 12,818,941 | 12,799,844 | 12,785,256 | 12,772,643 | 12,753,003 | 154,168,453 | 142,309,341 | 11,859,112 |
| 3 | Recoverable Costs Allocated to Energy | 995,032 | 995,603.80 | 995,171 | 994,642 | 987,677 | 987,136 | 986,181 | 986,072 | 984,603 | 983,481 | 982,511 | 981,000 | 11,859,112 | | |
| 4 | Recoverable Costs Allocated to Demand | 11,940,382 | 11,947,245.56 | 11,942,055 | 11,935,702 | 11,852,130 | 11,845,634 | 11,834,174 | 11,832,869 | 11,815,240 | 11,801,775 | 11,790,132 | 11,772,003 | 142,309,341 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | 964,879 | 966,645.06 | 966,988 | 967,388 | 961,141 | 961,328 | 960,440 | 959,893 | 958,716 | 956,634 | 954,168 | 951,221 | 11,529,442 | | |
| 8 | Jurisdictional Demand Recoverable Costs (C) | 11,590,703 | 11,597,365.70 | 11,592,327 | 11,586,160 | 11,505,036 | 11,498,729 | 11,487,606 | 11,486,338 | 11,469,226 | 11,456,155 | 11,444,854 | 11,427,255 | 138,141,755 | | |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | 12,555,581 | 12,564,011 | 12,559,315 | 12,553,548 | 12,466,177 | 12,460,058 | 12,448,046 | 12,446,231 | 12,427,942 | 12,412,789 | 12,399,022 | 12,378,476 | 149,671,197 | | |

Notes:

(A) Pages 1-27 of Schedule 4P, Line 9, Pages 28-31 of Schedule 4P, Line 6
(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 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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 | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | 33,678,001 | |
| 3 | Less: Accumulated Depreciation (C) | 2,995,197 | 2,891,196 | 2,787,195 | 2,683,194 | 2,579,194 | 2,475,193 | 2,371,192 | 2,267,191 | 2,163,191 | 2,059,190 | 1,955,189 | 1,851,188 | 1,747,188 | |
| 4 | 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) | 36,673,198 | 36,569,197 | 36,465,196 | 36,361,195 | 36,257,195 | 36,153,194 | 36,049,193 | 35,945,193 | 35,841,192 | 35,737,191 | 35,633,190 | 35,529,190 | 35,425,189 | |
| 6 | Average Net Investment | | 36,621,197 | 36,517,197 | 36,413,196 | 36,309,195 | 36,205,194 | 36,101,194 | 35,997,193 | 35,893,192 | 35,789,191 | 35,685,191 | 35,581,190 | 35,477,189 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 198,890 | 198,325 | 197,760 | 197,195 | 196,630 | 196,066 | 195,501 | 194,936 | 194,371 | 193,806 | 193,241 | 192,677 | 2,349,398 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 50,830 | 50,686 | 50,542 | 50,397 | 50,253 | 50,108 | 49,964 | 49,820 | 49,675 | 49,531 | 49,387 | 49,242 | 600,435 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 98,239 | 98,239 | 98,239 | 98,239 | 98,239 | 98,239 | 98,239 | 98,239 | 98,239 | 98,239 | 98,239 | 98,239 | 1,178,865 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 5,762 | 5,762 | 5,762 | 5,762 | 5,762 | 5,762 | 5,762 | 5,762 | 5,762 | 5,762 | 5,762 | 5,762 | 69,144 |
| | 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) | | 353,721 | 353,011 | 352,302 | 351,593 | 350,884 | 350,175 | 349,466 | 348,756 | 348,047 | 347,338 | 346,629 | 345,920 | 4,197,842 |
| | a Recoverable Costs Allocated to Energy | | 27,209 | 27,155 | 27,100 | 27,046 | 26,991 | 26,937 | 26,882 | 26,827 | 26,773 | 26,718 | 26,664 | 26,609 | 322,911 |
| | b Recoverable Costs Allocated to Demand | | 326,511 | 325,857 | 325,202 | 324,548 | 323,893 | 323,238 | 322,584 | 321,929 | 321,274 | 320,620 | 319,965 | 319,310 | 3,874,931 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 26,385 | 26,365 | 26,333 | 26,305 | 26,266 | 26,232 | 26,180 | 26,115 | 26,069 | 25,989 | 25,895 | 25,801 | 313,934 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 316,949 | 316,314 | 315,678 | 315,043 | 314,408 | 313,772 | 313,137 | 312,501 | 311,866 | 311,230 | 310,595 | 309,959 | 3,761,452 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 343,334 | 342,679 | 342,011 | 341,348 | 340,673 | 340,004 | 339,317 | 338,616 | 337,935 | 337,219 | 336,489 | 335,761 | 4,075,387 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | |
| 6 | Average Net Investment | | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | 1,449,490 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 7,872 | 7,872 | 7,872 | 7,872 | 7,872 | 7,872 | 7,872 | 7,872 | 7,872 | 7,872 | 7,872 | 7,872 | 94,466 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 2,012 | 2,012 | 2,012 | 2,012 | 2,012 | 2,012 | 2,012 | 2,012 | 2,012 | 2,012 | 2,012 | 2,012 | 24,143 |
| 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) | | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 9,884 | 118,609 |
| | a Recoverable Costs Allocated to Energy | | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 760 | 9,124 |
| | b Recoverable Costs Allocated to Demand | | 9,124 | 9,124 | 9,124 | 9,124 | 9,124 | 9,124 | 9,124 | 9,124 | 9,124 | 9,124 | 9,124 | 9,124 | 109,485 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 737 | 738 | 739 | 739 | 740 | 740 | 740 | 740 | 740 | 740 | 738 | 737 | 8,870 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 8,857 | 8,857 | 8,857 | 8,857 | 8,857 | 8,857 | 8,857 | 8,857 | 8,857 | 8,857 | 8,857 | 8,857 | 106,279 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 9,594 | 9,595 | 9,595 | 9,596 | 9,596 | 9,597 | 9,597 | 9,597 | 9,597 | 9,596 | 9,595 | 9,594 | 115,149 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Docket No. 150007-EI
ECRC 2016 Projection Filing
Exhibit CSB-3, Page 6 of 93

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 12,010,894 | 12,010,894 | 12,010,894 | 12,010,894 | 12,010,894 | 12,010,894 | 12,010,894 | 12,010,894 | 12,010,894 | 12,010,894 | 12,010,894 | 12,010,894 | 12,010,894 | |
| 3 | Less: Accumulated Depreciation (C) | 4,068,431 | 4,032,101 | 3,995,772 | 3,959,442 | 3,923,113 | 3,886,783 | 3,850,454 | 3,814,124 | 3,777,795 | 3,741,466 | 3,705,136 | 3,668,807 | 3,632,477 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 16,079,325 | 16,042,996 | 16,006,666 | 15,970,337 | 15,934,007 | 15,897,678 | 15,861,348 | 15,825,019 | 15,788,689 | 15,752,360 | 15,716,031 | 15,679,701 | 15,643,372 | |
| 6 | Average Net Investment | | 16,061,160 | 16,024,831 | 15,988,501 | 15,952,172 | 15,915,843 | 15,879,513 | 15,843,184 | 15,806,854 | 15,770,525 | 15,734,195 | 15,697,866 | 15,661,536 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 87,228 | 87,031 | 86,834 | 86,636 | 86,439 | 86,242 | 86,044 | 85,847 | 85,650 | 85,452 | 85,255 | 85,058 | 1,033,716 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 22,293 | 22,242 | 22,192 | 22,142 | 22,091 | 22,041 | 21,990 | 21,940 | 21,889 | 21,839 | 21,789 | 21,738 | 264,187 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 34,616 | 34,616 | 34,616 | 34,616 | 34,616 | 34,616 | 34,616 | 34,616 | 34,616 | 34,616 | 34,616 | 34,616 | 415,391 |
| | b Amortization (F) | | 1,714 | 1,714 | 1,714 | 1,714 | 1,714 | 1,714 | 1,714 | 1,714 | 1,714 | 1,714 | 1,714 | 1,714 | 20,562 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 145,851 | 145,603 | 145,355 | 145,107 | 144,860 | 144,612 | 144,364 | 144,116 | 143,869 | 143,621 | 143,373 | 143,125 | 1,733,856 |
| | a Recoverable Costs Allocated to Energy | | 11,219 | 11,200 | 11,181 | 11,162 | 11,143 | 11,124 | 11,105 | 11,086 | 11,067 | 11,048 | 11,029 | 11,010 | 133,374 |
| | b Recoverable Costs Allocated to Demand | | 134,631 | 134,403 | 134,174 | 133,945 | 133,717 | 133,488 | 133,259 | 133,031 | 132,802 | 132,573 | 132,344 | 132,116 | 1,600,482 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 10,879 | 10,874 | 10,865 | 10,856 | 10,844 | 10,833 | 10,815 | 10,792 | 10,776 | 10,746 | 10,711 | 10,675 | 129,666 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 130,689 | 130,467 | 130,245 | 130,023 | 129,801 | 129,579 | 129,357 | 129,135 | 128,913 | 128,691 | 128,469 | 128,247 | 1,553,612 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 141,568 | 141,341 | 141,109 | 140,879 | 140,644 | 140,412 | 140,172 | 139,926 | 139,689 | 139,437 | 139,179 | 138,922 | 1,683,277 |

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 PE 1236 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, & Daniel
P.E.s 1001, 1060, 1154, 1164, 1213, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1325, 1357, 1358, 1364, 1440, 1441, 1442, 1444, 1445, 1454, 1459, 1460, 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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 539,997 | 539,996 | 457,390 | 457,390 | 457,390 | 457,390 | 126,000 | 0 | 11,500 | 11,500 | 11,500 | 11,500 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 3,035,553 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 1,729,329 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 6,366,956 | 6,366,956 | 6,366,956 | 6,366,956 | 4,637,626 | 4,637,626 | 4,637,626 | 7,673,179 | 7,673,179 | 7,673,179 | 7,673,179 | 7,673,179 | 7,673,179 | |
| 3 | Less: Accumulated Depreciation (C) | 1,393,221 | 1,375,206 | 1,357,192 | 1,339,177 | 3,050,492 | 3,037,233 | 3,023,974 | 3,010,715 | 2,988,601 | 2,966,487 | 2,944,374 | 2,922,260 | 2,900,146 | |
| 4 | CWIP - Non Interest Bearing | 0 | 539,997 | 1,079,993 | 1,537,383 | 1,994,773 | 2,452,163 | 2,909,553 | 0 | 0 | 11,500 | 23,000 | 34,500 | 46,000 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 7,760,177 | 8,282,159 | 8,804,140 | 9,243,516 | 9,682,891 | 10,127,022 | 10,571,153 | 10,683,894 | 10,661,780 | 10,651,167 | 10,640,553 | 10,629,939 | 10,619,326 | |
| 6 | Average Net Investment | | 8,021,168 | 8,543,150 | 9,023,828 | 9,463,203 | 9,904,956 | 10,349,088 | 10,627,524 | 10,672,837 | 10,656,474 | 10,645,860 | 10,635,246 | 10,624,632 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 43,563 | 46,398 | 49,008 | 51,395 | 53,794 | 56,206 | 57,718 | 57,964 | 57,875 | 57,818 | 57,760 | 57,702 | 647,201 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 11,133 | 11,858 | 12,525 | 13,135 | 13,748 | 14,365 | 14,751 | 14,814 | 14,791 | 14,776 | 14,762 | 14,747 | 165,405 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 17,919 | 17,919 | 17,919 | 17,919 | 13,163 | 13,163 | 13,163 | 22,018 | 22,018 | 22,018 | 22,018 | 22,018 | 221,255 |
| | b Amortization (F) | | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 1,149 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 12,629 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 73,763 | 77,323 | 80,601 | 83,597 | 81,853 | 84,882 | 86,781 | 95,944 | 95,833 | 95,760 | 95,688 | 95,616 | 1,047,640 |
| | a Recoverable Costs Allocated to Energy | | 5,674 | 5,948 | 6,200 | 6,431 | 6,296 | 6,529 | 6,675 | 7,380 | 7,372 | 7,366 | 7,361 | 7,355 | 80,588 |
| | b Recoverable Costs Allocated to Demand | | 68,089 | 71,375 | 74,401 | 77,166 | 75,557 | 78,352 | 80,105 | 88,564 | 88,461 | 88,394 | 88,327 | 88,260 | 967,052 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 5,502 | 5,775 | 6,024 | 6,254 | 6,127 | 6,359 | 6,501 | 7,184 | 7,178 | 7,165 | 7,148 | 7,132 | 78,350 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 66,095 | 69,285 | 72,222 | 74,906 | 73,344 | 76,058 | 77,759 | 85,970 | 85,870 | 85,805 | 85,741 | 85,676 | 938,731 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 71,597 | 75,060 | 78,246 | 81,161 | 79,471 | 82,417 | 84,260 | 93,155 | 93,048 | 92,971 | 92,889 | 92,807 | 1,017,082 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist $4,053,254; Smith $1,729,329; Daniel $584,373. Ending Balances: Crist $7,088,807; Smith $0; 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) Portions of PE 1283 has a 7 year amortization period. PEs 1364 & 1658 are fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (417,510) | (422,006) | (426,501) | (430,997) | (435,493) | (439,988) | (444,484) | (448,980) | (453,475) | (457,971) | (462,467) | (466,962) | (471,458) | |
| 4 | 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) | 2,065,823 | 2,061,328 | 2,056,832 | 2,052,336 | 2,047,841 | 2,043,345 | 2,038,850 | 2,034,354 | 2,029,858 | 2,025,363 | 2,020,867 | 2,016,371 | 2,011,876 | |
| 6 | Average Net Investment | | 2,063,576 | 2,059,080 | 2,054,584 | 2,050,089 | 2,045,593 | 2,041,097 | 2,036,602 | 2,032,106 | 2,027,610 | 2,023,115 | 2,018,619 | 2,014,123 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 11,207 | 11,183 | 11,158 | 11,134 | 11,110 | 11,085 | 11,061 | 11,036 | 11,012 | 10,988 | 10,963 | 10,939 | 132,876 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 2,864 | 2,858 | 2,852 | 2,846 | 2,839 | 2,833 | 2,827 | 2,821 | 2,814 | 2,808 | 2,802 | 2,796 | 33,959 |
| 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) | | 18,567 | 18,537 | 18,506 | 18,475 | 18,445 | 18,414 | 18,383 | 18,353 | 18,322 | 18,291 | 18,261 | 18,230 | 220,783 |
| | a Recoverable Costs Allocated to Energy | | 1,428 | 1,426 | 1,424 | 1,421 | 1,419 | 1,416 | 1,414 | 1,412 | 1,409 | 1,407 | 1,405 | 1,402 | 16,983 |
| | b Recoverable Costs Allocated to Demand | | 17,139 | 17,111 | 17,082 | 17,054 | 17,026 | 16,997 | 16,969 | 16,941 | 16,913 | 16,884 | 16,856 | 16,828 | 203,799 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,385 | 1,384 | 1,383 | 1,382 | 1,381 | 1,379 | 1,377 | 1,374 | 1,372 | 1,369 | 1,364 | 1,360 | 16,511 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 16,637 | 16,610 | 16,582 | 16,555 | 16,527 | 16,500 | 16,472 | 16,445 | 16,417 | 16,390 | 16,362 | 16,335 | 197,831 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 18,022 | 17,994 | 17,965 | 17,937 | 17,908 | 17,879 | 17,849 | 17,819 | 17,790 | 17,758 | 17,726 | 17,695 | 214,342 |

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) The amortizable portion of 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | 242,973 | |
| 3 | Less: Accumulated Depreciation (C) | (120,731) | (121,424) | (122,118) | (122,811) | (123,504) | (124,197) | (124,890) | (125,584) | (126,277) | (126,970) | (127,663) | (128,357) | (129,050) | |
| 4 | 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) | 122,241 | 121,548 | 120,855 | 120,162 | 119,469 | 118,775 | 118,082 | 117,389 | 116,696 | 116,002 | 115,309 | 114,616 | 113,923 | |
| 6 | Average Net Investment | | 121,895 | 121,202 | 120,508 | 119,815 | 119,122 | 118,429 | 117,735 | 117,042 | 116,349 | 115,656 | 114,963 | 114,269 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 662 | 658 | 654 | 651 | 647 | 643 | 639 | 636 | 632 | 628 | 624 | 621 | 7,696 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 169 | 168 | 167 | 166 | 165 | 164 | 163 | 162 | 161 | 161 | 160 | 159 | 1,967 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 693 | 8,319 |
| | 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) | | 1,524 | 1,520 | 1,515 | 1,510 | 1,506 | 1,501 | 1,496 | 1,491 | 1,487 | 1,482 | 1,477 | 1,472 | 17,981 |
| | a Recoverable Costs Allocated to Energy | | 117 | 117 | 117 | 116 | 116 | 115 | 115 | 115 | 114 | 114 | 114 | 113 | 1,383 |
| | b Recoverable Costs Allocated to Demand | | 1,407 | 1,403 | 1,398 | 1,394 | 1,390 | 1,385 | 1,381 | 1,377 | 1,372 | 1,368 | 1,364 | 1,359 | 16,598 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 114 | 113 | 113 | 113 | 113 | 112 | 112 | 112 | 111 | 111 | 110 | 110 | 1,345 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 1,366 | 1,362 | 1,357 | 1,353 | 1,349 | 1,345 | 1,341 | 1,336 | 1,332 | 1,328 | 1,324 | 1,319 | 16,112 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,480 | 1,475 | 1,471 | 1,466 | 1,462 | 1,457 | 1,453 | 1,448 | 1,443 | 1,439 | 1,434 | 1,429 | 17,456 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist $149,950; Smith $93,023.
(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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | |
| 6 | Average Net Investment | | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | 492,255 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 2,673 | 2,673 | 2,673 | 2,673 | 2,673 | 2,673 | 2,673 | 2,673 | 2,673 | 2,673 | 2,673 | 2,673 | 32,081 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 683 | 683 | 683 | 683 | 683 | 683 | 683 | 683 | 683 | 683 | 683 | 683 | 8,199 |
| 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) | | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 3,357 | 40,280 |
| | a Recoverable Costs Allocated to Energy | | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 3,098 |
| | b Recoverable Costs Allocated to Demand | | 3,098 | 3,098 | 3,098 | 3,098 | 3,098 | 3,098 | 3,098 | 3,098 | 3,098 | 3,098 | 3,098 | 3,098 | 37,182 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 250 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 250 | 3,012 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 3,008 | 3,008 | 3,008 | 3,008 | 3,008 | 3,008 | 3,008 | 3,008 | 3,008 | 3,008 | 3,008 | 3,008 | 36,093 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 3,258 | 3,258 | 3,259 | 3,259 | 3,259 | 3,259 | 3,259 | 3,259 | 3,259 | 3,259 | 3,258 | 3,258 | 39,105 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (202,040) | (203,151) | (204,261) | (205,372) | (206,482) | (207,593) | (208,703) | (209,814) | (210,924) | (212,035) | (213,145) | (214,256) | (215,366) | |
| 4 | 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) | 178,657 | 177,546 | 176,436 | 175,325 | 174,215 | 173,104 | 171,994 | 170,883 | 169,773 | 168,662 | 167,552 | 166,441 | 165,331 | |
| 6 | Average Net Investment | | 178,101 | 176,991 | 175,880 | 174,770 | 173,659 | 172,549 | 171,438 | 170,328 | 169,217 | 168,107 | 166,996 | 165,886 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 967 | 961 | 955 | 949 | 943 | 937 | 931 | 925 | 919 | 913 | 907 | 901 | 11,209 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 247 | 246 | 244 | 243 | 241 | 239 | 238 | 236 | 235 | 233 | 232 | 230 | 2,865 |
| 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) | | 2,325 | 2,317 | 2,310 | 2,302 | 2,295 | 2,287 | 2,280 | 2,272 | 2,264 | 2,257 | 2,249 | 2,242 | 27,400 |
| | a Recoverable Costs Allocated to Energy | | 179 | 178 | 178 | 177 | 177 | 176 | 175 | 175 | 174 | 174 | 173 | 172 | 2,108 |
| | b Recoverable Costs Allocated to Demand | | 2,146 | 2,139 | 2,132 | 2,125 | 2,118 | 2,111 | 2,104 | 2,097 | 2,090 | 2,083 | 2,076 | 2,069 | 25,292 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 173 | 173 | 173 | 172 | 172 | 171 | 171 | 170 | 170 | 169 | 168 | 167 | 2,049 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,083 | 2,076 | 2,070 | 2,063 | 2,056 | 2,049 | 2,043 | 2,036 | 2,029 | 2,022 | 2,015 | 2,009 | 24,552 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,257 | 2,250 | 2,242 | 2,235 | 2,228 | 2,221 | 2,213 | 2,206 | 2,199 | 2,191 | 2,183 | 2,176 | 26,601 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (43,306) | (43,507) | (43,708) | (43,909) | (44,110) | (44,311) | (44,512) | (44,713) | (44,914) | (45,115) | (45,316) | (45,517) | (45,718) | |
| 4 | 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) | 25,617 | 25,416 | 25,215 | 25,014 | 24,813 | 24,612 | 24,411 | 24,210 | 24,009 | 23,808 | 23,607 | 23,406 | 23,205 | |
| 6 | Average Net Investment | | 25,517 | 25,316 | 25,115 | 24,914 | 24,713 | 24,512 | 24,311 | 24,110 | 23,909 | 23,708 | 23,506 | 23,305 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 139 | 137 | 136 | 135 | 134 | 133 | 132 | 131 | 130 | 129 | 128 | 127 | 1,591 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 35 | 35 | 35 | 35 | 34 | 34 | 34 | 33 | 33 | 33 | 33 | 32 | 407 |
| 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) | | 375 | 374 | 372 | 371 | 370 | 368 | 367 | 365 | 364 | 363 | 361 | 360 | 4,410 |
| | a Recoverable Costs Allocated to Energy | | 29 | 29 | 29 | 29 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 339 |
| | b Recoverable Costs Allocated to Demand | | 346 | 345 | 344 | 342 | 341 | 340 | 339 | 337 | 336 | 335 | 334 | 332 | 4,071 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 28 | 28 | 28 | 28 | 28 | 28 | 27 | 27 | 27 | 27 | 27 | 27 | 330 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 336 | 335 | 334 | 332 | 331 | 330 | 329 | 327 | 326 | 325 | 324 | 323 | 3,952 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 364 | 363 | 361 | 360 | 359 | 357 | 356 | 355 | 354 | 352 | 351 | 349 | 4,281 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 | 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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (72,984) | (73,280) | (73,576) | (73,872) | (74,168) | (74,464) | (74,760) | (75,056) | (75,352) | (75,648) | (75,945) | (76,241) | (76,537) | |
| 4 | 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) | 28,511 | 28,215 | 27,919 | 27,623 | 27,327 | 27,031 | 26,735 | 26,439 | 26,143 | 25,847 | 25,551 | 25,254 | 24,958 | |
| 6 | Average Net Investment | | 28,363 | 28,067 | 27,771 | 27,475 | 27,179 | 26,883 | 26,587 | 26,291 | 25,995 | 25,699 | 25,403 | 25,106 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 154 | 152 | 151 | 149 | 148 | 146 | 144 | 143 | 141 | 140 | 138 | 136 | 1,742 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 39 | 39 | 39 | 38 | 38 | 37 | 37 | 36 | 36 | 36 | 35 | 35 | 445 |
| 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) | | 489 | 487 | 485 | 483 | 481 | 479 | 477 | 475 | 473 | 471 | 469 | 467 | 5,740 |
| | a Recoverable Costs Allocated to Energy | | 38 | 37 | 37 | 37 | 37 | 37 | 37 | 37 | 36 | 36 | 36 | 36 | 442 |
| | b Recoverable Costs Allocated to Demand | | 452 | 450 | 448 | 446 | 444 | 443 | 441 | 439 | 437 | 435 | 433 | 431 | 5,299 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 37 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 35 | 35 | 35 | 35 | 429 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 439 | 437 | 435 | 433 | 431 | 430 | 428 | 426 | 424 | 422 | 420 | 419 | 5,144 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 475 | 473 | 471 | 469 | 467 | 465 | 463 | 462 | 460 | 458 | 456 | 454 | 5,573 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

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ECRC 2016 Projection Filing
Exhibit CSB-3, Page 14 of 93

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (43,135) | (43,308) | (43,482) | (43,656) | (43,830) | (44,003) | (44,177) | (44,351) | (44,524) | (44,698) | (44,872) | (45,045) | (45,219) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 16,408 | 16,234 | 16,061 | 15,887 | 15,713 | 15,540 | 15,366 | 15,192 | 15,018 | 14,845 | 14,671 | 14,497 | 14,324 | |
| 6 | Average Net Investment | | 16,321 | 16,147 | 15,974 | 15,800 | 15,626 | 15,453 | 15,279 | 15,105 | 14,932 | 14,758 | 14,584 | 14,411 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 89 | 88 | 87 | 86 | 85 | 84 | 83 | 82 | 81 | 80 | 79 | 78 | 1,001 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 23 | 22 | 22 | 22 | 22 | 21 | 21 | 21 | 21 | 20 | 20 | 20 | 256 |
| 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) | | 285 | 284 | 283 | 281 | 280 | 279 | 278 | 277 | 276 | 274 | 273 | 272 | 3,342 |
| | a Recoverable Costs Allocated to Energy | | 22 | 22 | 22 | 22 | 22 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 257 |
| | b Recoverable Costs Allocated to Demand | | 263 | 262 | 261 | 260 | 259 | 258 | 257 | 255 | 254 | 253 | 252 | 251 | 3,085 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 20 | 20 | 250 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 255 | 254 | 253 | 252 | 251 | 250 | 249 | 248 | 247 | 246 | 245 | 244 | 2,994 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 277 | 275 | 274 | 273 | 272 | 271 | 270 | 269 | 268 | 266 | 265 | 264 | 3,244 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E.s 1214 & 1413
(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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 106,497 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 391,119 | 391,119 | 391,119 | 391,119 | 284,622 | 284,622 | 284,622 | 284,622 | 284,622 | 284,622 | 284,622 | 284,622 | 284,622 | |
| 3 | Less: Accumulated Depreciation (C) | (152,626) | (153,749) | (154,872) | (155,995) | (50,621) | (51,451) | (52,282) | (53,112) | (53,942) | (54,772) | (55,603) | (56,433) | (57,263) | |
| 4 | 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) | 238,493 | 237,370 | 236,247 | 235,124 | 234,001 | 233,170 | 232,340 | 231,510 | 230,680 | 229,849 | 229,019 | 228,189 | 227,359 | |
| 6 | Average Net Investment | | 237,931 | 236,808 | 235,685 | 234,562 | 233,585 | 232,755 | 231,925 | 231,095 | 230,264 | 229,434 | 228,604 | 227,774 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 1,292 | 1,286 | 1,280 | 1,274 | 1,269 | 1,264 | 1,260 | 1,255 | 1,251 | 1,246 | 1,242 | 1,237 | 15,155 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 330 | 329 | 327 | 326 | 324 | 323 | 322 | 321 | 320 | 318 | 317 | 316 | 3,873 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 1,123 | 1,123 | 1,123 | 1,123 | 830 | 830 | 830 | 830 | 830 | 830 | 830 | 830 | 11,134 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 2,746 | 2,738 | 2,730 | 2,723 | 2,423 | 2,417 | 2,412 | 2,406 | 2,400 | 2,395 | 2,389 | 2,383 | 30,162 |
| | a Recoverable Costs Allocated to Energy | | 211 | 211 | 210 | 209 | 186 | 186 | 186 | 185 | 185 | 184 | 184 | 183 | 2,320 |
| | b Recoverable Costs Allocated to Demand | | 2,534 | 2,527 | 2,520 | 2,513 | 2,237 | 2,231 | 2,226 | 2,221 | 2,216 | 2,211 | 2,205 | 2,200 | 27,842 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 205 | 204 | 204 | 204 | 181 | 181 | 181 | 180 | 180 | 179 | 178 | 178 | 2,256 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,460 | 2,453 | 2,446 | 2,440 | 2,171 | 2,166 | 2,161 | 2,156 | 2,151 | 2,146 | 2,141 | 2,136 | 27,027 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,665 | 2,658 | 2,650 | 2,643 | 2,353 | 2,347 | 2,342 | 2,336 | 2,331 | 2,325 | 2,319 | 2,313 | 29,282 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist $284,622; Smith $106,497. Ending Balances: Crist $284,622; Smith $0.
(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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | |
| 3 | Less: Accumulated Depreciation (C) | (1,763,579) | (1,771,232) | (1,778,884) | (1,786,536) | (1,794,188) | (1,801,840) | (1,809,492) | (1,817,145) | (1,824,797) | (1,832,449) | (1,840,101) | (1,847,753) | (1,855,405) | |
| 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) | 1,019,021 | 1,011,369 | 1,003,716 | 996,064 | 988,412 | 980,760 | 973,108 | 965,456 | 957,804 | 950,151 | 942,499 | 934,847 | 927,195 | |
| 6 | Average Net Investment | | 1,015,195 | 1,007,543 | 999,890 | 992,238 | 984,586 | 976,934 | 969,282 | 961,630 | 953,978 | 946,325 | 938,673 | 931,021 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 5,514 | 5,472 | 5,430 | 5,389 | 5,347 | 5,306 | 5,264 | 5,223 | 5,181 | 5,139 | 5,098 | 5,056 | 63,419 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,409 | 1,398 | 1,388 | 1,377 | 1,367 | 1,356 | 1,345 | 1,335 | 1,324 | 1,313 | 1,303 | 1,292 | 16,208 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 91,826 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 14,575 | 14,523 | 14,470 | 14,418 | 14,366 | 14,314 | 14,262 | 14,210 | 14,157 | 14,105 | 14,053 | 14,001 | 171,453 |
| | a Recoverable Costs Allocated to Energy | | 1,121 | 1,117 | 1,113 | 1,109 | 1,105 | 1,101 | 1,097 | 1,093 | 1,089 | 1,085 | 1,081 | 1,077 | 13,189 |
| | b Recoverable Costs Allocated to Demand | | 13,454 | 13,405 | 13,357 | 13,309 | 13,261 | 13,213 | 13,165 | 13,116 | 13,068 | 13,020 | 12,972 | 12,924 | 158,265 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,087 | 1,085 | 1,082 | 1,079 | 1,075 | 1,072 | 1,068 | 1,064 | 1,060 | 1,055 | 1,050 | 1,044 | 12,822 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 13,060 | 13,013 | 12,966 | 12,919 | 12,873 | 12,826 | 12,779 | 12,732 | 12,686 | 12,639 | 12,592 | 12,545 | 153,630 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 14,147 | 14,098 | 14,048 | 13,998 | 13,948 | 13,898 | 13,848 | 13,796 | 13,746 | 13,694 | 13,642 | 13,590 | 166,452 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | 60,095 | 59,602 | 59,110 | 58,618 | 58,126 | 57,634 | 57,142 | 56,649 | 56,157 | 55,665 | 55,173 | 54,681 | 54,189 | |
| 4 | 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) | 239,056 | 238,564 | 238,072 | 237,580 | 237,088 | 236,596 | 236,104 | 235,611 | 235,119 | 234,627 | 234,135 | 233,643 | 233,151 | |
| 6 | Average Net Investment | | 238,810 | 238,318 | 237,826 | 237,334 | 236,842 | 236,350 | 235,857 | 235,365 | 234,873 | 234,381 | 233,889 | 233,397 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 1,297 | 1,294 | 1,292 | 1,289 | 1,286 | 1,284 | 1,281 | 1,278 | 1,276 | 1,273 | 1,270 | 1,268 | 15,387 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 331 | 331 | 330 | 329 | 329 | 328 | 327 | 327 | 326 | 325 | 325 | 324 | 3,933 |
| 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) | | 2,121 | 2,117 | 2,114 | 2,111 | 2,107 | 2,104 | 2,100 | 2,097 | 2,094 | 2,090 | 2,087 | 2,084 | 25,226 |
| | a Recoverable Costs Allocated to Energy | | 163 | 163 | 163 | 162 | 162 | 162 | 162 | 161 | 161 | 161 | 161 | 160 | 1,940 |
| | b Recoverable Costs Allocated to Demand | | 1,957 | 1,954 | 1,951 | 1,948 | 1,945 | 1,942 | 1,939 | 1,936 | 1,933 | 1,930 | 1,927 | 1,923 | 23,285 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 158 | 158 | 158 | 158 | 158 | 158 | 157 | 157 | 157 | 156 | 156 | 155 | 1,886 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 1,900 | 1,897 | 1,894 | 1,891 | 1,888 | 1,885 | 1,882 | 1,879 | 1,876 | 1,873 | 1,870 | 1,867 | 22,603 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,058 | 2,055 | 2,052 | 2,049 | 2,046 | 2,043 | 2,039 | 2,036 | 2,033 | 2,029 | 2,026 | 2,022 | 24,490 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (7,274,790) | (7,318,664) | (7,362,539) | (7,406,414) | (7,450,288) | (7,494,163) | (7,538,037) | (7,581,912) | (7,625,787) | (7,669,661) | (7,713,536) | (7,757,411) | (7,801,285) | |
| 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) (A) | 7,675,334 | 7,631,460 | 7,587,585 | 7,543,710 | 7,499,836 | 7,455,961 | 7,412,087 | 7,368,212 | 7,324,337 | 7,280,463 | 7,236,588 | 7,192,713 | 7,148,839 | |
| 6 | Average Net Investment | | 7,653,397 | 7,609,522 | 7,565,648 | 7,521,773 | 7,477,899 | 7,434,024 | 7,390,149 | 7,346,275 | 7,302,400 | 7,258,525 | 7,214,651 | 7,170,776 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 41,566 | 41,327 | 41,089 | 40,851 | 40,612 | 40,374 | 40,136 | 39,898 | 39,659 | 39,421 | 39,183 | 38,944 | 483,061 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 10,623 | 10,562 | 10,501 | 10,440 | 10,379 | 10,318 | 10,258 | 10,197 | 10,136 | 10,075 | 10,014 | 9,953 | 123,456 |
| 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 | 8,996 | 8,996 | 8,996 | 8,996 | 8,996 | 8,996 | 107,952 |
| | d Property Taxes | | 21,791 | 21,791 | 21,791 | 21,791 | 21,791 | 21,791 | 21,791 | 21,791 | 21,791 | 21,791 | 21,791 | 21,791 | 261,495 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 117,854 | 117,555 | 117,256 | 116,957 | 116,658 | 116,358 | 116,059 | 115,760 | 115,461 | 115,162 | 114,863 | 114,563 | 1,394,507 |
| | a Recoverable Costs Allocated to Energy | | 9,066 | 9,043 | 9,020 | 8,997 | 8,974 | 8,951 | 8,928 | 8,905 | 8,882 | 8,859 | 8,836 | 8,813 | 107,270 |
| | b Recoverable Costs Allocated to Demand | | 108,789 | 108,513 | 108,236 | 107,960 | 107,684 | 107,408 | 107,132 | 106,856 | 106,579 | 106,303 | 106,027 | 105,751 | 1,287,237 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 8,791 | 8,780 | 8,764 | 8,750 | 8,733 | 8,717 | 8,695 | 8,668 | 8,648 | 8,617 | 8,581 | 8,545 | 104,288 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 105,603 | 105,335 | 105,067 | 104,799 | 104,530 | 104,262 | 103,994 | 103,726 | 103,458 | 103,190 | 102,922 | 102,654 | 1,249,540 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 114,394 | 114,114 | 113,831 | 113,549 | 113,263 | 112,979 | 112,689 | 112,394 | 112,106 | 111,807 | 111,503 | 111,199 | 1,353,827 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E.s 1601, 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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 340,807 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 16,904,173 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 134,134 | 17,038,307 | 17,038,307 | 17,038,307 | 17,038,307 | 17,038,307 | 17,038,307 | 17,038,307 | 17,038,307 | 17,038,307 | 17,038,307 | 17,038,307 | 17,038,307 | |
| 3 | Less: Accumulated Depreciation (C) | (48,479) | (48,848) | (49,217) | (49,585) | (49,954) | (50,323) | (50,692) | (51,061) | (51,430) | (51,799) | (52,167) | (52,536) | (52,905) | |
| 4 | CWIP - Non Interest Bearing | 16,563,366 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 16,649,021 | 16,989,459 | 16,989,091 | 16,988,722 | 16,988,353 | 16,987,984 | 16,987,615 | 16,987,246 | 16,986,877 | 16,986,509 | 16,986,140 | 16,985,771 | 16,985,402 | |
| 6 | Average Net Investment | | 16,819,240 | 16,989,275 | 16,988,906 | 16,988,537 | 16,988,168 | 16,987,800 | 16,987,431 | 16,987,062 | 16,986,693 | 16,986,324 | 16,985,955 | 16,985,586 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 91,345 | 92,269 | 92,267 | 92,265 | 92,263 | 92,261 | 92,259 | 92,257 | 92,255 | 92,253 | 92,251 | 92,249 | 1,106,191 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 23,345 | 23,581 | 23,581 | 23,580 | 23,580 | 23,579 | 23,579 | 23,578 | 23,578 | 23,577 | 23,577 | 23,576 | 282,709 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 4,426 |
| | 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) | | 115,059 | 116,219 | 116,216 | 116,214 | 116,211 | 116,209 | 116,206 | 116,204 | 116,201 | 116,199 | 116,196 | 116,194 | 1,393,327 |
| | a Recoverable Costs Allocated to Energy | | 8,851 | 8,940 | 8,940 | 8,940 | 8,939 | 8,939 | 8,939 | 8,939 | 8,939 | 8,938 | 8,938 | 8,938 | 107,179 |
| | b Recoverable Costs Allocated to Demand | | 106,209 | 107,279 | 107,277 | 107,274 | 107,272 | 107,270 | 107,267 | 107,265 | 107,263 | 107,260 | 107,258 | 107,256 | 1,286,148 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 8,583 | 8,680 | 8,687 | 8,695 | 8,699 | 8,705 | 8,706 | 8,701 | 8,704 | 8,694 | 8,680 | 8,667 | 104,200 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 103,098 | 104,137 | 104,135 | 104,133 | 104,130 | 104,128 | 104,126 | 104,124 | 104,121 | 104,119 | 104,117 | 104,115 | 1,248,483 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 111,681 | 112,817 | 112,821 | 112,827 | 112,830 | 112,834 | 112,831 | 112,825 | 112,825 | 112,813 | 112,797 | 112,781 | 1,352,683 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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 | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 17,241 | 201,341 | 69,741 | 0 | 152,482 | 0 | 0 | 0 | 76,241 | 318,750 | 271,249 | 76,239 | |
| | b Clearings to Plant | | 0 | 0 | 467,630 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 894,961 | |
| | c Retirements | | 0 | 0 | 33,888 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 25,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 119,510,628 | 119,510,628 | 119,510,628 | 119,944,370 | 119,944,370 | 119,944,370 | 119,944,370 | 119,944,370 | 119,944,370 | 119,944,370 | 119,944,370 | 119,944,370 | 120,839,331 | |
| 3 | Less: Accumulated Depreciation (C) | (28,080,807) | (28,431,884) | (28,757,962) | (29,075,151) | (29,426,229) | (29,777,306) | (30,128,383) | (30,479,461) | (30,830,538) | (31,181,616) | (31,532,693) | (31,883,771) | (32,234,848) | |
| 4 | CWIP - Non Interest Bearing | 219,799 | 237,040 | 438,381 | 40,492 | 40,492 | 192,974 | 192,974 | 192,974 | 192,974 | 269,215 | 587,965 | 859,214 | 40,492 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 91,649,619 | 91,315,783 | 91,191,047 | 90,909,710 | 90,558,633 | 90,360,037 | 90,008,960 | 89,657,882 | 89,306,805 | 89,031,969 | 88,999,641 | 88,919,813 | 88,644,974 | |
| 6 | Average Net Investment | | 91,482,701 | 91,253,415 | 91,050,378 | 90,734,171 | 90,459,335 | 90,184,499 | 89,833,421 | 89,482,344 | 89,169,387 | 89,015,805 | 88,959,727 | 88,782,394 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 496,843 | 495,597 | 494,495 | 492,777 | 491,285 | 489,792 | 487,885 | 485,979 | 484,279 | 483,445 | 483,140 | 482,177 | 5,867,694 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 126,978 | 126,660 | 126,378 | 125,939 | 125,558 | 125,176 | 124,689 | 124,201 | 123,767 | 123,554 | 123,476 | 123,230 | 1,499,606 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 308,939 | 308,939 | 308,939 | 308,939 | 308,939 | 308,939 | 308,939 | 308,939 | 308,939 | 308,939 | 308,939 | 308,939 | 3,707,272 |
| | b Amortization (F) | | 9,468 | 9,468 | 9,468 | 9,468 | 9,468 | 9,468 | 9,468 | 9,468 | 9,468 | 9,468 | 9,468 | 9,468 | 113,617 |
| | c Dismantlement | | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 32,670 | 392,040 |
| | 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) | | 974,898 | 973,334 | 971,950 | 969,794 | 967,920 | 966,046 | 963,652 | 961,258 | 959,123 | 958,076 | 957,694 | 956,485 | 11,580,228 |
| | a Recoverable Costs Allocated to Energy | | 74,992 | 74,872 | 74,765 | 74,600 | 74,455 | 74,311 | 74,127 | 73,943 | 73,779 | 73,698 | 73,669 | 73,576 | 890,787 |
| | b Recoverable Costs Allocated to Demand | | 899,906 | 898,463 | 897,185 | 895,194 | 893,464 | 891,734 | 889,524 | 887,315 | 885,345 | 884,378 | 884,025 | 882,909 | 10,689,442 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 72,720 | 72,694 | 72,648 | 72,555 | 72,455 | 72,368 | 72,192 | 71,980 | 71,839 | 71,686 | 71,544 | 71,342 | 866,024 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 873,552 | 872,151 | 870,910 | 868,978 | 867,299 | 865,620 | 863,474 | 861,329 | 859,417 | 858,479 | 858,136 | 857,052 | 10,376,397 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 946,271 | 944,845 | 943,558 | 941,534 | 939,754 | 937,988 | 935,667 | 933,309 | 931,256 | 930,165 | 929,680 | 928,395 | 11,242,421 |

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 have a 7-year amortization period. The amortizable portion of 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.s 1272, 1404, & 1628
(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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | 934,730 | |
| 3 | Less: Accumulated Depreciation (C) | (285,241) | (287,965) | (290,689) | (293,414) | (296,138) | (298,862) | (301,586) | (304,310) | (307,034) | (309,758) | (312,482) | (315,206) | (317,931) | |
| 4 | 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) | 649,489 | 646,765 | 644,041 | 641,317 | 638,593 | 635,868 | 633,144 | 630,420 | 627,696 | 624,972 | 622,248 | 619,524 | 616,800 | |
| 6 | Average Net Investment | | 648,127 | 645,403 | 642,679 | 639,955 | 637,230 | 634,506 | 631,782 | 629,058 | 626,334 | 623,610 | 620,886 | 618,162 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 3,520 | 3,505 | 3,490 | 3,476 | 3,461 | 3,446 | 3,431 | 3,416 | 3,402 | 3,387 | 3,372 | 3,357 | 41,263 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 900 | 896 | 892 | 888 | 884 | 881 | 877 | 873 | 869 | 866 | 862 | 858 | 10,546 |
| 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) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 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) | | 7,144 | 7,125 | 7,107 | 7,088 | 7,069 | 7,051 | 7,032 | 7,014 | 6,995 | 6,977 | 6,958 | 6,939 | 84,498 |
| | a Recoverable Costs Allocated to Energy | | 550 | 548 | 547 | 545 | 544 | 542 | 541 | 540 | 538 | 537 | 535 | 534 | 6,500 |
| | b Recoverable Costs Allocated to Demand | | 6,594 | 6,577 | 6,560 | 6,543 | 6,526 | 6,508 | 6,491 | 6,474 | 6,457 | 6,440 | 6,423 | 6,406 | 77,999 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 533 | 532 | 531 | 530 | 529 | 528 | 527 | 525 | 524 | 522 | 520 | 518 | 6,319 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 6,401 | 6,384 | 6,368 | 6,351 | 6,334 | 6,318 | 6,301 | 6,285 | 6,268 | 6,251 | 6,235 | 6,218 | 75,714 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 6,934 | 6,917 | 6,899 | 6,881 | 6,864 | 6,846 | 6,828 | 6,810 | 6,792 | 6,773 | 6,754 | 6,736 | 82,033 |

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) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (25,123) | (25,307) | (25,490) | (25,674) | (25,857) | (26,040) | (26,224) | (26,407) | (26,591) | (26,774) | (26,957) | (27,141) | (27,324) | |
| 4 | 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) | 37,747 | 37,564 | 37,380 | 37,197 | 37,013 | 36,830 | 36,647 | 36,463 | 36,280 | 36,096 | 35,913 | 35,730 | 35,546 | |
| 6 | Average Net Investment | | 37,655 | 37,472 | 37,288 | 37,105 | 36,922 | 36,738 | 36,555 | 36,372 | 36,188 | 36,005 | 35,821 | 35,638 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 205 | 204 | 203 | 202 | 201 | 200 | 199 | 198 | 197 | 196 | 195 | 194 | 2,388 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 52 | 52 | 52 | 52 | 51 | 51 | 51 | 50 | 50 | 50 | 50 | 49 | 610 |
| 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) | | 440 | 439 | 438 | 436 | 435 | 434 | 433 | 431 | 430 | 429 | 428 | 426 | 5,199 |
| | a Recoverable Costs Allocated to Energy | | 34 | 34 | 34 | 34 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 400 |
| | b Recoverable Costs Allocated to Demand | | 406 | 405 | 404 | 403 | 402 | 401 | 399 | 398 | 397 | 396 | 395 | 394 | 4,799 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 33 | 33 | 33 | 33 | 33 | 33 | 32 | 32 | 32 | 32 | 32 | 32 | 389 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 394 | 393 | 392 | 391 | 390 | 389 | 388 | 387 | 385 | 384 | 383 | 382 | 4,659 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 427 | 426 | 425 | 424 | 422 | 421 | 420 | 419 | 418 | 416 | 415 | 414 | 5,048 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E.s 1175, 1191, 1305, 1330, 1461, 1462
(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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 15,715,201 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 29,712,897 | 29,712,897 | 29,712,897 | 29,712,897 | 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) | (8,334,047) | (8,418,095) | (8,502,143) | (8,586,192) | 7,044,962 | 7,004,130 | 6,963,299 | 6,922,468 | 6,881,636 | 6,840,805 | 6,799,974 | 6,759,143 | 6,718,311 | |
| 4 | 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) | 21,378,850 | 21,294,802 | 21,210,754 | 21,126,705 | 21,042,657 | 21,001,826 | 20,960,995 | 20,920,164 | 20,879,332 | 20,838,501 | 20,797,670 | 20,756,838 | 20,716,007 | |
| 6 | Average Net Investment | | 21,336,826 | 21,252,778 | 21,168,729 | 21,084,681 | 21,022,242 | 20,981,410 | 20,940,579 | 20,899,748 | 20,858,917 | 20,818,085 | 20,777,254 | 20,736,423 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 115,880 | 115,424 | 114,967 | 114,511 | 114,172 | 113,950 | 113,728 | 113,507 | 113,285 | 113,063 | 112,841 | 112,620 | 1,367,948 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 29,616 | 29,499 | 29,382 | 29,266 | 29,179 | 29,122 | 29,066 | 29,009 | 28,952 | 28,896 | 28,839 | 28,782 | 349,606 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 84,048 | 84,048 | 84,048 | 84,048 | 40,831 | 40,831 | 40,831 | 40,831 | 40,831 | 40,831 | 40,831 | 40,831 | 662,843 |
| | 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) | | 229,544 | 228,971 | 228,398 | 227,825 | 184,182 | 183,904 | 183,625 | 183,347 | 183,068 | 182,790 | 182,511 | 182,233 | 2,380,396 |
| | a Recoverable Costs Allocated to Energy | | 17,657 | 17,613 | 17,569 | 17,525 | 14,168 | 14,146 | 14,125 | 14,104 | 14,082 | 14,061 | 14,039 | 14,018 | 183,107 |
| | b Recoverable Costs Allocated to Demand | | 211,887 | 211,358 | 210,829 | 210,300 | 170,014 | 169,757 | 169,500 | 169,243 | 168,986 | 168,729 | 168,472 | 168,215 | 2,197,289 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 17,122 | 17,101 | 17,071 | 17,045 | 13,787 | 13,777 | 13,756 | 13,729 | 13,712 | 13,677 | 13,634 | 13,592 | 178,004 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 205,681 | 205,168 | 204,654 | 204,141 | 165,035 | 164,786 | 164,536 | 164,287 | 164,037 | 163,788 | 163,538 | 163,289 | 2,132,941 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 222,804 | 222,269 | 221,726 | 221,186 | 178,822 | 178,562 | 178,293 | 178,016 | 177,749 | 177,465 | 177,173 | 176,881 | 2,310,945 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist $13,997,696; Smith $15,715,201. Ending Balances: Crist $13,997,696; Smith $0.
(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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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 | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
Return on Capital Investments, Depreciation and Taxes
For Project: Plant 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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | 20,023,891 | |
| 3 | Less: Accumulated Depreciation (C) | (3,971,136) | (4,029,545) | (4,087,955) | (4,146,365) | (4,204,774) | (4,263,184) | (4,321,594) | (4,380,003) | (4,438,413) | (4,496,823) | (4,555,233) | (4,613,642) | (4,672,052) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 16,052,755 | 15,994,346 | 15,935,936 | 15,877,526 | 15,819,117 | 15,760,707 | 15,702,297 | 15,643,888 | 15,585,478 | 15,527,068 | 15,468,658 | 15,410,249 | 15,351,839 | |
| 6 | Average Net Investment | | 16,023,551 | 15,965,141 | 15,906,731 | 15,848,322 | 15,789,912 | 15,731,502 | 15,673,092 | 15,614,683 | 15,556,273 | 15,497,863 | 15,439,454 | 15,381,044 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 87,024 | 86,707 | 86,389 | 86,072 | 85,755 | 85,438 | 85,121 | 84,803 | 84,486 | 84,169 | 83,852 | 83,534 | 1,023,350 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 22,241 | 22,160 | 22,079 | 21,997 | 21,916 | 21,835 | 21,754 | 21,673 | 21,592 | 21,511 | 21,430 | 21,349 | 261,537 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 58,410 | 700,916 |
| | 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) | | 167,674 | 167,276 | 166,878 | 166,479 | 166,081 | 165,683 | 165,285 | 164,886 | 164,488 | 164,090 | 163,691 | 163,293 | 1,985,804 |
| | a Recoverable Costs Allocated to Energy | | 12,898 | 12,867 | 12,837 | 12,806 | 12,775 | 12,745 | 12,714 | 12,684 | 12,653 | 12,622 | 12,592 | 12,561 | 152,754 |
| | b Recoverable Costs Allocated to Demand | | 154,776 | 154,409 | 154,041 | 153,673 | 153,306 | 152,938 | 152,570 | 152,203 | 151,835 | 151,467 | 151,100 | 150,732 | 1,833,050 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 12,507 | 12,493 | 12,473 | 12,455 | 12,432 | 12,412 | 12,382 | 12,347 | 12,320 | 12,278 | 12,228 | 12,180 | 148,508 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 150,244 | 149,887 | 149,530 | 149,173 | 148,816 | 148,459 | 148,102 | 147,745 | 147,388 | 147,032 | 146,675 | 146,318 | 1,779,368 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 162,751 | 162,380 | 162,003 | 161,628 | 161,248 | 160,871 | 160,485 | 160,092 | 159,709 | 159,309 | 158,903 | 158,497 | 1,927,876 |

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 compoocnt has been grossed up for taxes. Tbc 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 Linc 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 | 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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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) | (1,968,600) | (1,986,549) | (2,004,497) | (2,022,446) | (2,040,395) | (2,058,344) | (2,076,292) | (2,094,241) | (2,112,190) | (2,130,138) | (2,148,087) | (2,166,036) | (2,183,984) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 4,184,540 | 4,166,591 | 4,148,643 | 4,130,694 | 4,112,745 | 4,094,797 | 4,076,848 | 4,058,899 | 4,040,951 | 4,023,002 | 4,005,053 | 3,987,104 | 3,969,156 | |
| 6 | Average Net Investment | | 4,175,566 | 4,157,617 | 4,139,668 | 4,121,720 | 4,103,771 | 4,085,822 | 4,067,874 | 4,049,925 | 4,031,976 | 4,014,027 | 3,996,079 | 3,978,130 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 22,677 | 22,580 | 22,483 | 22,385 | 22,288 | 22,190 | 22,093 | 21,995 | 21,898 | 21,800 | 21,703 | 21,605 | 265,696 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 5,796 | 5,771 | 5,746 | 5,721 | 5,696 | 5,671 | 5,646 | 5,621 | 5,596 | 5,571 | 5,547 | 5,522 | 67,904 |
| 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) | | 46,422 | 46,300 | 46,177 | 46,055 | 45,932 | 45,810 | 45,688 | 45,565 | 45,443 | 45,320 | 45,198 | 45,076 | 548,985 |
| | a Recoverable Costs Allocated to Energy | | 3,571 | 3,562 | 3,552 | 3,543 | 3,533 | 3,524 | 3,514 | 3,505 | 3,496 | 3,486 | 3,477 | 3,467 | 42,230 |
| | b Recoverable Costs Allocated to Demand | | 42,851 | 42,738 | 42,625 | 42,512 | 42,399 | 42,286 | 42,173 | 42,060 | 41,947 | 41,834 | 41,721 | 41,608 | 506,755 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 3,463 | 3,458 | 3,451 | 3,446 | 3,438 | 3,432 | 3,423 | 3,412 | 3,404 | 3,391 | 3,376 | 3,362 | 41,056 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 41,596 | 41,486 | 41,377 | 41,267 | 41,157 | 41,048 | 40,938 | 40,828 | 40,719 | 40,609 | 40,499 | 40,390 | 491,915 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 45,059 | 44,944 | 44,828 | 44,713 | 44,596 | 44,479 | 44,361 | 44,240 | 44,122 | 44,000 | 43,876 | 43,752 | 532,970 |

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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Compliance Program
P.E.s 1034, 1035, 1036, 1037, 1067, 1075, 1095, 1168, 1187, 1188, 1222, 1233, 1259, 1279, 1288, 1362, 1468, 1469, 1505, 1508, 1512, 1513, 1517, 1551, 1552, 1646, 1647, 1684, 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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 3,707,838 | 1,644,655 | 1,566,036 | 1,509,761 | 1,503,091 | 1,527,099 | 430,937 | 87,207 | 1,092,814 | 1,076,031 | 1,116,693 | 1,076,043 | |
| | b Clearings to Plant | | 3,126,175 | 1,062,993 | 1,066,980 | 1,010,705 | 1,004,035 | 988,668 | 3,793,098 | 45,541 | 45,503 | 28,720 | 28,720 | 4,063,250 | |
| | c Retirements | | 0 | 0 | 0 | 12,701,643 | 0 | 0 | 0 | 0 | 0 | 0 | 2,068,161 | 996,591 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 368,150 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 80,000 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 1,163,876,874 | 1,167,003,049 | 1,168,066,042 | 1,169,133,022 | 1,157,442,083 | 1,158,446,118 | 1,159,434,786 | 1,163,227,884 | 1,163,273,425 | 1,163,318,928 | 1,163,347,648 | 1,161,308,207 | 1,164,374,866 | |
| 3 | Less: Accumulated Depreciation (C) | (178,371,900) | (181,877,822) | (185,391,037) | (188,906,732) | (179,723,273) | (183,208,886) | (186,696,841) | (190,187,103) | (193,688,402) | (197,189,808) | (200,691,321) | (201,756,589) | (204,335,611) | |
| 4 | CWIP - Non Interest Bearing | 2,474,894 | 3,056,557 | 3,638,219 | 4,137,275 | 4,636,331 | 5,135,387 | 5,673,818 | 2,311,657 | 2,353,323 | 3,400,634 | 4,447,945 | 5,535,918 | 2,548,711 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 987,979,867 | 988,181,784 | 986,313,223 | 984,363,564 | 982,355,141 | 980,372,619 | 978,411,763 | 975,352,438 | 971,938,345 | 969,529,754 | 967,104,272 | 965,087,536 | 962,587,966 | |
| 6 | Average Net Investment | | 988,080,825 | 987,247,503 | 985,338,394 | 983,359,353 | 981,363,880 | 979,392,191 | 976,882,101 | 973,645,392 | 970,734,049 | 968,317,013 | 966,095,904 | 963,837,751 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 5,366,267 | 5,361,741 | 5,351,373 | 5,340,625 | 5,329,787 | 5,319,079 | 5,305,447 | 5,287,868 | 5,272,057 | 5,258,930 | 5,246,867 | 5,234,603 | 63,674,643 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,371,456 | 1,370,300 | 1,367,650 | 1,364,903 | 1,362,133 | 1,359,396 | 1,355,912 | 1,351,420 | 1,347,379 | 1,344,024 | 1,340,941 | 1,337,807 | 16,273,321 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 3,167,588 | 3,174,881 | 3,177,361 | 3,179,850 | 3,147,279 | 3,149,621 | 3,151,928 | 3,162,966 | 3,163,072 | 3,163,178 | 3,163,245 | 3,157,279 | 37,958,248 |
| | b Amortization (F) | | 23,437 | 23,437 | 23,437 | 23,437 | 23,437 | 23,437 | 23,437 | 23,437 | 23,437 | 23,437 | 23,437 | 23,437 | 281,244 |
| | c Dismantlement | | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 314,897 | 3,778,764 |
| | d Property Taxes | | 351,836 | 351,836 | 351,836 | 351,836 | 351,836 | 351,836 | 351,836 | 351,836 | 351,836 | 351,836 | 351,836 | 351,836 | 4,222,033 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 10,595,481 | 10,597,092 | 10,586,554 | 10,575,548 | 10,529,369 | 10,518,267 | 10,503,457 | 10,492,424 | 10,472,678 | 10,456,302 | 10,441,223 | 10,419,859 | 126,188,252 |
| | a Recoverable Costs Allocated to Energy | | 815,037 | 815,161 | 814,350 | 813,504 | 809,951 | 809,097 | 807,958 | 807,110 | 805,591 | 804,331 | 803,171 | 801,528 | 9,706,789 |
| | b Recoverable Costs Allocated to Demand | | 9,780,444 | 9,781,931 | 9,772,203 | 9,762,044 | 9,719,418 | 9,709,169 | 9,695,499 | 9,685,314 | 9,667,087 | 9,651,971 | 9,638,052 | 9,618,331 | 116,481,463 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 790,338 | 791,451 | 791,288 | 791,213 | 788,190 | 787,944 | 786,869 | 785,681 | 784,410 | 782,374 | 780,002 | 777,197 | 9,436,958 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 9,494,020 | 9,495,463 | 9,486,020 | 9,476,159 | 9,434,781 | 9,424,832 | 9,411,562 | 9,401,676 | 9,383,982 | 9,369,309 | 9,355,798 | 9,336,655 | 113,070,257 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 10,284,358 | 10,286,914 | 10,277,308 | 10,267,372 | 10,222,971 | 10,212,776 | 10,198,431 | 10,187,357 | 10,168,392 | 10,151,684 | 10,135,800 | 10,113,852 | 122,507,215 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $783,351,695; Smith $12,931,385; Daniel $367,593,793. Ending Balances: Crist $788,097,895; Smith $229,742; Daniel $376,047,229.
(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 1222, 1233, 1279 and 1909 have a 7 year amortization period. PE 1168 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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 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 | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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) Fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residual
P.E.s 0404, 0412, 0514, 1193, 1597, 1598, 1599, 1641, 1912, 1997
(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 Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 770,384 | 770,384 | 870,384 | 770,384 | 770,384 | 770,384 | 770,384 | 770,384 | 770,384 | 770,384 | 770,384 | 785,376 | |
| | b Clearings to Plant | | 0 | 0 | 100,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 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 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 660,000 | 660,000 | 660,000 | 760,000 | 760,000 | 760,000 | 760,000 | 760,000 | 760,000 | 760,000 | 760,000 | 760,000 | 760,000 | |
| 3 | Less: Accumulated Depreciation (C) | 0 | (1,785) | (3,570) | (5,355) | (7,415) | (9,475) | (11,535) | (13,595) | (15,655) | (17,715) | (19,775) | (21,835) | (23,895) | |
| 4 | CWIP - Non Interest Bearing | 0 | 770,384 | 1,540,768 | 2,311,152 | 3,081,536 | 3,851,920 | 4,622,304 | 5,392,688 | 6,163,072 | 6,933,456 | 7,703,840 | 8,474,224 | 9,259,600 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (A) | 660,000 | 1,428,599 | 2,197,198 | 3,065,797 | 3,834,121 | 4,602,445 | 5,370,769 | 6,139,093 | 6,907,417 | 7,675,741 | 8,444,065 | 9,212,389 | 9,995,705 | |
| 6 | Average Net Investment | | 1,044,299 | 1,812,898 | 2,631,497 | 3,449,959 | 4,218,283 | 4,986,607 | 5,754,931 | 6,523,255 | 7,291,579 | 8,059,903 | 8,828,227 | 9,604,047 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component (Line 6 x Equity Component x 1/12) (D) | | 5,672 | 9,846 | 14,292 | 18,737 | 22,909 | 27,082 | 31,255 | 35,428 | 39,601 | 43,773 | 47,946 | 52,160 | 348,700 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,449 | 2,516 | 3,653 | 4,789 | 5,855 | 6,921 | 7,988 | 9,054 | 10,121 | 11,187 | 12,254 | 13,330 | 89,117 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 1,785 | 1,785 | 1,785 | 2,060 | 2,060 | 2,060 | 2,060 | 2,060 | 2,060 | 2,060 | 2,060 | 2,060 | 23,895 |
| | 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) | | 8,906 | 14,147 | 19,729 | 25,585 | 30,825 | 36,064 | 41,303 | 46,542 | 51,781 | 57,021 | 62,260 | 67,550 | 461,713 |
| | a Recoverable Costs Allocated to Energy | | 685 | 1,088 | 1,518 | 1,968 | 2,371 | 2,774 | 3,177 | 3,580 | 3,983 | 4,386 | 4,789 | 5,196 | 35,516 |
| | b Recoverable Costs Allocated to Demand | | 8,221 | 13,059 | 18,212 | 23,617 | 28,453 | 33,290 | 38,126 | 42,962 | 47,798 | 52,634 | 57,471 | 62,354 | 426,196 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 664 | 1,057 | 1,475 | 1,914 | 2,307 | 2,702 | 3,094 | 3,485 | 3,878 | 4,266 | 4,651 | 5,038 | 34,532 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 7,980 | 12,677 | 17,678 | 22,926 | 27,620 | 32,315 | 37,009 | 41,704 | 46,398 | 51,093 | 55,787 | 60,528 | 413,715 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 8,645 | 13,733 | 19,153 | 24,840 | 29,928 | 35,016 | 40,103 | 45,189 | 50,277 | 55,359 | 60,439 | 65,566 | 448,247 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $270,000; Smith $210,000; Daniel $180,000. Ending Balances: Crist $270,000; Smith $310,000; Daniel $180,000.
(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 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 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 | 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 | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 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.

Docket No. 150007-EI
ECRC 2016 Projection Filing
Exhibit CSB-3, Page 32 of 93

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**
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 | 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 Annual Nox 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 | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 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 2016 - December 2016**
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 | 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 Seasonal NOx 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 | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 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 1.0015 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 2016 - December 2016**
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 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 | 6,234,958 | 6,218,949 | 6,206,873 | 6,194,974 | 6,179,110 | 6,153,958 | 6,135,905 | 6,104,998 | 6,074,746 | 6,057,104 | 6,030,719 | 6,016,976 | 6,000,356 | |
| | 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 | (8,137) | (7,438) | (6,738) | (6,039) | (5,339) | (4,640) | (3,940) | (3,241) | (2,542) | (1,842) | (1,143) | (443) | 256 | |
| 3 | Total Working Capital Balance | 6,226,821 | 6,211,511 | 6,200,135 | 6,188,936 | 6,173,771 | 6,149,318 | 6,131,964 | 6,101,756 | 6,072,204 | 6,055,262 | 6,029,576 | 6,016,533 | 6,000,612 | |
| 4 | Average Net Working Capital Balance | | 6,219,166 | 6,205,823 | 6,194,535 | 6,181,353 | 6,161,544 | 6,140,641 | 6,116,860 | 6,086,980 | 6,063,733 | 6,042,419 | 6,023,054 | 6,008,572 | |
| 5 | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a Equity Component (Line 4 x Equity Component x 1/12) (A) | | 33,776 | 33,704 | 33,643 | 33,571 | 33,463 | 33,350 | 33,221 | 33,058 | 32,932 | 32,816 | 32,711 | 32,633 | 398,878 |
| | b Debt Component (Line 4 x Debt Component x 1/12) | | 8,632 | 8,614 | 8,598 | 8,580 | 8,552 | 8,523 | 8,490 | 8,449 | 8,416 | 8,387 | 8,360 | 8,340 | 101,941 |
| 6 | Total Return Component (D) | | 42,408 | 42,318 | 42,241 | 42,151 | 42,016 | 41,873 | 41,711 | 41,507 | 41,349 | 41,203 | 41,071 | 40,972 | 500,819 |
| 7 | Expenses | | | | | | | | | | | | | | |
| | a Gains | | (699) | (699) | (699) | (699) | (699) | (699) | (699) | (699) | (699) | (699) | (699) | (699) | (8,393) |
| | b Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c SO2 Allowance Expense | | 16,009 | 12,076 | 11,898 | 15,865 | 25,152 | 18,053 | 30,907 | 30,252 | 17,642 | 26,385 | 13,743 | 16,620 | 234,602 |
| 8 | Net Expenses (E) | | 15,310 | 11,377 | 11,199 | 15,165 | 24,453 | 17,354 | 30,208 | 29,552 | 16,943 | 25,686 | 13,043 | 15,921 | 226,209 |
| 9 | Total System Recoverable Expenses (Lines 6 + 8) | | 57,718 | 53,694 | 53,440 | 57,316 | 66,468 | 59,227 | 71,918 | 71,059 | 58,291 | 66,889 | 54,114 | 56,893 | 727,028 |
| | a Recoverable Costs Allocated to Energy | | 18,572 | 14,632 | 14,448 | 18,407 | 27,685 | 20,575 | 33,416 | 32,745 | 20,123 | 28,855 | 16,203 | 19,072 | 264,734 |
| | b Recoverable Costs Allocated to Demand | | 39,146 | 39,062 | 38,991 | 38,908 | 38,784 | 38,652 | 38,502 | 38,314 | 38,168 | 38,034 | 37,912 | 37,821 | 462,295 |
| 10 | Energy Jurisdictional Factor | | 0.9682439 | 0.9694592 | 0.9702248 | 0.9711428 | 0.9716749 | 0.9723972 | 0.9724397 | 0.9719927 | 0.9722491 | 0.9712453 | 0.9696982 | 0.9681922 | |
| 11 | Demand Jurisdictional Factor | | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | 0.9707146 | |
| 12 | Retail Energy-Related Recoverable Costs (B) | | 18,009 | 14,206 | 14,039 | 17,903 | 26,941 | 20,037 | 32,544 | 31,876 | 19,594 | 28,068 | 15,735 | 18,493 | 257,445 |
| 13 | Retail Demand-Related Recoverable Costs (C) | | 38,000 | 37,918 | 37,849 | 37,769 | 37,648 | 37,520 | 37,375 | 37,192 | 37,050 | 36,920 | 36,802 | 36,713 | 448,756 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 56,009 | 52,125 | 51,888 | 55,672 | 64,589 | 57,557 | 69,919 | 69,068 | 56,644 | 64,988 | 52,537 | 55,207 | 706,202 |

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x 1.0015 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)
January 2016-December 2016

**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 CEM system was replaced during the 2002-2003 recovery period. The CEMS trailer was also replaced in 2010. 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: $0**

**Progress Summary:** Retired.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 as a result of burning low sulfur coal. 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 will be upgraded during 2015.

**Project-to-Date:** Plant-in-service of $33,678,001 projected at December 2016.

**Progress Summary:** In Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 2016-December 2016

**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 will be upgraded during 2015.

**Project-to-Date:** Plant-in-service of $12,010,894 projected at December 2016.

**Progress Summary:** In-Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: CEMs – Plant Crist, Scholz, Smith, and Daniel**
**PEs 1001, 1060, 1154, 1164, 1213, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1325, 1357, 1358, 1364, 1440, 1441, 1442, 1444, 1445, 1454, 1459, 1460, 1558, 1570, 1592, 1658, 1829, and 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 $7,673,179 projected at December 2016.

**Progress Summary:**
The Plant Scholz Units 1 & 2 CEMS analyzer replacements and the Smith Unit 1 gas analyzers and opacity monitor replacements were completed in 2001 and 2002. The Plant Crist Unit 6 & 7 and the Plant Scholz Units 1 & 2 flow monitors were replaced during 2005. The Plant Daniel Units 1 & 2 gas analyzers were also replaced during 2005 and the flow monitors were replaced during 2007. During 2008, the opacity, flow, and gas monitors at Plant Smith and opacity and gas monitors at Plant Scholz were replaced. 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. During 2016, Plant Crist will upgrade and relocate the CEMS bypass monitoring system from the stack to the individual unit duct to comply with the MATS rule and upgrade Plant Crist's Unit 7 flue gas monitors. The Smith CEMS systems are projected to be retired in April 2016 after the coal units cease operations in March 2016. The Scholz CEMS systems were retired in 2015 after the coal units ceased operation.

**Projections:** Expenditures reflected in the 2016 projection filing for this line item total $3,081,553

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 $2,483,333 projected at December 2016.

**Progress Summary:** N/A

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 $242,973 projected at December 2016.

**Progress Summary:** In-Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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.

**Project-to-Date:** $0

**Progress Summary:** Retired

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Crist Dechlorination System**
**PE 1180 and PE 1248**

**FPSC Approval: Order No. PSC-94-1207-FOF-EI**

**Description:**
State and Federal Pollution Discharge Elimination System permits require significant 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 2016.

**Progress Summary:** In service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 to determine if groundwater contamination was present. 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 2016.

**Progress Summary:** In-Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 must 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 2016.

**Progress Summary:** In-Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 2016.

**Progress Summary:** In-Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Sodium Injection System**
**PEs 1214 and 1413**

**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 is used at Plant Smith on Units 1 and 2 and 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 Plants Smith and Crist have been installed. These systems are fully operational. The Smith systems are projected to be retired in April 2016 after the coal units cease operations in March 2016.

**Project-to-Date:** Plant-in-service of $284,622 projected at December 2016.

**Progress Summary:** In Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 unpermitted discharge of contaminated 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 $2,782,600 projected at December 2016.

**Progress Summary:** In-Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 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 $178,962 projected at December 2016.

**Progress Summary:** In-Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 2016.

**Progress Summary:** In-Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Smith Water Conservation**
**PEs 1601, 1620, & 1638**

**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 and will begin the process of installing piping and initial equipment for the pump station during the latter portion of 2015 and the first part of 2016. During 2016, Gulf will obtain additional operational data required to design the final pump station and wastewater treatment equipment as well as any additional piping.

**Accomplishments:** Plant Smith estimated that the closed loop cooling project reduced water consumption by approximately 125,000 gallons per day.

**Project-to-Date:** Plant-in-service of $17,038,307 projected at December 2016.

**Progress Summary:** See Accomplishments

**Projections:** The projected 2016 expenditures for this line item total $340,807.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 Recovey Clause (ECRC)
January 2016-December 2016

**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 plans to add or replace a layer of the Plant Crist unit 7 SCR catalyst and install the Plant Crist unit 6 flame scanner during 2016.

**Project-to-Date:** Plant-in-service of $120,839,331 projected at December 2016.

**Progress Summary:** In-Service.

**Projections:** The projected 2016 expenditures for this line item total $1,183,284.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: SPCC Compliance**
**PEs 1272, 1404, and 1628**

**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.

**Project-to-Date:** Plant-in-service of $934,730 projected at December 2016.

**Progress Summary:** In-service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 2016

**Progress Summary:** In-Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Precipitator Upgrades for Compliance Assurance Monitoring Compliance PEs 1175, 1191, 1305, 1330, 1461, and 1462**

**FPSC Approval: Order No. PSC-04-1187-FOF-EI**

**Description:** Compliance Assurance Monitoring (CAM) Precipitator Upgrades were required to comply with new CAM regulations. 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 are projected to be retired in April 2016 after Plant Smith Units 1 & 2 cease operations in March 2016.

**Project-to-Date:** Plant-in-service of $13,997,696 projected at December 2016.

**Progress Summary:** See Accomplishments

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 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 2016-December 2016

**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 Number19850074 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.

**Project-to-Date:** Plant-in-service of $20,023,891 projected at December 2016.

**Progress Summary:** See Accomplishments

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Plant NPDES Permit Compliance Projects**
**PE 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 Pollution 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.

**Project-to-Date:** Plant-in-service of $6,153,140 projected at December 2016.

**Progress Summary:** See Accomplishments

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Air Quality Compliance Program**
**PEs 1034, 1035, 1036, 1037, 1067, 1075, 1095, 1168, 1187, 1188, 1222, 1233, 1259, 1279, 1362, 1468, 1469, 1505, 1508, 1512, 1513, 1517, 1551, 1552, 1646, 1647, 1684, 1809, 1810, 1824, 1826, 1909, 1911, 1913, and 1950**

**FPSC Approval: Order No. PSC-06-0972-FOF-EI**

**Description:** This line item includes the prudently incurred costs for compliance with Gulf's Air Quality Compliance Program.

**Accomplishments:** The Plant Smith Unit 1 and Unit 2 SNCRs were placed in service during May 2009 and December 2008, respectively. 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. Gulf added an additional catalyst layer to the Plant Crist Unit 6 SCR in 2015. The digital control systems for the Unit 6 SCR and the scrubber were upgraded in 2015.

**Project-to-Date:** Plant-in-service of $1,164,403,582 projected at December 2016.

**Progress Summary:** Gulf Power began installing MATS monitoring systems at Plant Plant Crist in 2014 and Plant Daniel in 2015 to comply with the MATS rule. The 2016 projected expenditures for the Plant Crist MATS monitoring systems are $3.2 million. The Plant Daniel MATS monitoring costs are included in the cost projection for the Plant Daniel scrubbers. Also, projected for this line item are capital retrofit projects for the Plant Crist scrubber. Gulf plans to replace Plant Crist's scrubber booster fan hubs, scrubber mist eliminator, and scrubber expansion joints, as well as increase the capacity of its scrubber wastewater treatment plant.

The Plant Daniel scrubber projects are currently scheduled for completion in October and November 2015. The 2016 capital expenditures for Gulf's ownership portion of the scrubber are projected to be $8.5 million. The scrubbers when used in conjunction with the bromine and activated carbon injection systems will allow Plant Daniel to comply with the MATS standards.

**Projections:** The projected 2016 expenditures for this line item total $16,338,205.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: General Water Quality**
**PE 1280**

**FPSC Approval: Order No. PSC-06-0972-FOF-EI**

**Description:** Gulf Power 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.

**Project-to-Date:** $0.

**Progress Summary:** Retired

**Projections: N/A**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Coal Combustion Residual**
**PEs 0404, 0412, 0514, 1193, 1597, 1598, 1599, 1641, 1912, 1997**

**FPSC Approval:**

**Description:** 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 CCR rule includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills (collectively referred to as "CCR Units"). Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. The new criteria will apply to CCR Units at Gulf's Plants Crist, Smith, and Daniel.

**Accomplishments:** Gulf is planning to install groundwater monitoring wells at Plants Crist, Daniel, and Smith during 2015. The projected 2015 capital expenditures total $660,000.

**Project-to-Date:** Plant-in-service of $760,000 projected at December 2016.

**Progress Summary:** N/A

**Projections:** The proposed 2016 capital expenditures totaling $9,359,600 are associated with the installation of a new bottom ash handling system for Plant Crist, dust suppression control equipment for Plant Smith, as well as new CCR wastewater management systems for Plant Crist and Plant Smith.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 2016-December 2016

**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. 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:** Gulf is not projecting the need to purchase additional annual NOx CSAPR allowances during 2016.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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, they 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. 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:** Gulf is not projecting the need to purchase additional seasonal NOx allowances during 2016.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 utilize 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**: Gulf is not projecting the need to purchase any additional $SO_2$ allowances during 2016. The projected 2016 O&M $SO_2$ allowance expenses are $226,209.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 2016-December 2016

**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) 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:** $560,352

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 the 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. 2009, 2014, etc). Title V permits are periodically revised between renewals to incorporate major changes or modifications of a source.

**Accomplishments:**
Gulf applied for Title V permit renewals for Plant Crist, Plant Scholz, and Plant Smith on May 19, 2014. An application to renew the Pea Ridge facility was submitted on July 25, 2014. All Title V 2014 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 July, 2015 for Plant Crist, Plant Scholz and Plant Smith. Gulf's Perdido Landfill Gas-to-Energy Facility Title V permit is valid until March 1, 2017 and is not currently up for renewal.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments

**Projections:** $144,489

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 2016-December 2016

**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:** $816,217

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 permit including dechlorination, surface and groundwater monitoring studies as well as 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:** The 2016 projected costs for this line item are $2,009,676.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 92 sites.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments

**Projections:** $3,437,656

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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:** $36,500

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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:** $16,974

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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:** $9,000

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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:** $771,232

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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:** $164,181

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 on Plant Crist Units 4 & 5 and Plant Smith Unit 1 have been installed and are in-service. Plant Smith Unit 1 is projected to cease operations in March 2016. The Smith Unit 1 Low NOx burners are scheduled to be retired in April 2016.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 ash pond were required to effectively increase water retention time in the ash pond. Diversion curtains allow for the sedimentation/precipitation treatment process to be more effective in reducing levels of suspended particulate from the Plant Crist ash pond 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 2016-December 2016

**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 2016.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 the O&M expenses associated with the sodium injection systems at Plant Smith and Plant Crist. Sodium carbonate is added to the Plant Crist and Plant Smith coal supply to enhance precipitator efficiencies when burning certain low sulfur coals.

**Accomplishments:**
Sodium carbonate injection is used at Plant Smith and Plant Crist as necessary when low sulfur coal is burned.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments

**Projections:** $72,800

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 2016-December 2016

**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 July 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 reasonable 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 2016-December 2016

**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 the 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. 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:** $952,387

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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**

**Description:** This line item includes the O&M expenses associated with Gulf's Air Quality Compliance program and the Climate Registry. 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 are projected to be retired in April 2016 after the coal units cease operations in March 2016. 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 are currently scheduled for completion in the October to November 2015 time period. The Plant Daniel Bromine and Activated Carbon Injection systems will be completed during the same timeframe. Gulf will be incurring O&M expenses associated with these projects during 2016.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments

**Projections:** $27,146,432

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**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 2016-December 2016

**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 and valve maintenance and pump replacements.

**Accomplishments:**
Gulfs began receiving reclaimed water from ECUA during November 2010.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments

**Projections:** $570,300

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2016-December 2016

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.23**

**Title: Coal Combustion Residual**

**FPSC Approval:**

**Description:** 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 new rule will apply to CCR Units at Gulf's Plants Crist, Smith, and Daniel.

In addition, pursuant to its authority granted under the Clean Water Act, the FDEP issues National Pollutant Discharge Elimination System (NPDES) permits for each of Gulf's generating facilities. A draft NPDES renewal permit for Plant Scholz (FL0002283) was issued on August 24, 2015 and is expected to become final in the fourth quarter of 2015. This permit renewal has new conditions requiring closure of the Plant Scholz CCR Unit.

**Accomplishments:**
By the effective date of the CCR rule, October 19, 2015, any CCR Unit subject to the EPA's new rule must have a publicly available website established, weekly and monthly inspections initiated, and a fugitive dust plan prepared. During 2015, Gulf is also required to install permanent markers at all CCR ponds and have annual inspections of the CCR impoundments and landfills performed by a professional engineer (PE). In 2016, Gulf will prepare closure and post-closure care plans for the CCR Units, conduct hydrologic and hydraulic capacity studies of the CCR ponds, compile a history of the structural integrity reports and design information for the CCR Units, prepare stormwater management plans, and conduct annual dust control and engineering inspections as well as groundwater monitoring.

Pursuant to the draft Plant Scholz NPDES permit, a CCR closure plan is required to be submitted to the FDEP in 2016 for review and approval. Once approved, Gulf will move forward with activities required for closure.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments

**Projections:** $680,000 in 2015 and $12,560,000 in 2016

Schedule 6P

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
**Calculation of the Energy & Demand Allocation % By Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) Average 12 CP Load Factor at Meter (%) | (2) Jan - Dec. 2016 Projected Sales at Meter (KWH) | (3) Projected Avg 12 CP at Meter (KW) | (4) Demand Loss Expansion Factor | (5) Energy Loss Expansion Factor | (6) Projected Sales at Generation (KWH) | (7) Projected Avg 12 CP at Generation (KW) | (8) Percentage of KWH Sales at Generation (%) | (9) Percentage of 12 CP Demand at Generation (%) |
|---|---|---|---|---|---|---|---|---|---|
| RS, RSVP, RSTOU | 57.025261% | 5,268,731,000 | 1,051,832 | 1.00820508 | 1.00777864 | 5,309,714,562 | 1,060,462 | 48.17163% | 57.28868% |
| GS | 65.082883% | 283,353,000 | 49,564 | 1.00820395 | 1.00777656 | 285,556,512 | 49,971 | 2.59067% | 2.69954% |
| GSD, GSDT, GSTOU | 75.900487% | 2,572,527,000 | 385,854 | 1.00800263 | 1.00762887 | 2,592,152,474 | 388,942 | 23.51693% | 21.01155% |
| LP, LPT | 85.148219% | 979,635,000 | 130,977 | 0.97344897 | 0.98364378 | 963,611,874 | 127,500 | 8.74223% | 6.88784% |
| PX, PXT, RTP, SBS | 88.430490% | 1,773,222,000 | 228,280 | 0.95247952 | 0.96644352 | 1,713,718,911 | 217,432 | 15.54747% | 11.74621% |
| OS-I/II | 782.722832% | 111,141,000 | 1,616 | 1.00802086 | 1.00777465 | 112,005,082 | 1,629 | 1.01615% | 0.08803% |
| OS-III | 101.182319% | 45,381,000 | 5,106 | 1.00838359 | 1.00778595 | 45,734,334 | 5,149 | 0.41492% | 0.27815% |
| TOTAL | | 11,033,990,000 | 1,853,231 | | | 11,022,493,749 | 1,851,086 | 100.00000% | 100.00000% |

Notes:
(1) Average 12 CP load factor based on actual 2012 load research data
(2) Projected KWH sales for the period January 2016 - December 2016
(3) Calculated: (Col 2) / (8,784 x Col 1), (8,784 hours = the # of hours in 1 year)
(4) Based on demand losses identified in Docket No. 110138-EI
(5) Based on energy losses identified in Docket No. 110138-EI
(6) Col 2 x Col 5
(7) Col 3 x Col 4
(8) Col 6 / total for Col 6
(9) Col 7 / total for Col 7

Schedule 7P

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
**Calculation of the Energy & Demand Allocation % By Rate Class**
**January 2016 - December 2016**

| Rate Class | (1) Percentage of KWH Sales at Generation (%) | (2) Percentage of 12 CP Demand at Generation (%) | (3) Energy-Related Costs | (4) Demand-Related Costs | (5) Total Environmental Costs | (6) Projected Sales at Meter (KWH) | (7) Environmental Cost Recovery Factors (¢/KWH) |
|---|---|---|---|---|---|---|---|
| RS, RSVP, RSTOU | 48.17163% | 57.28868% | 19,833,434 | 91,289,022 | 111,122,456 | 5,268,731,000 | 2.109 |
| GS | 2.59067% | 2.69954% | 1,066,642 | 4,301,694 | 5,368,336 | 283,353,000 | 1.895 |
| GSD, GSDT, GSTOU | 23.51693% | 21.01155% | 9,682,494 | 33,481,725 | 43,164,219 | 2,572,527,000 | 1.678 |
| LP, LPT | 8.74223% | 6.88784% | 3,599,389 | 10,975,714 | 14,575,103 | 979,635,000 | 1.488 |
| PX, PXT, RTP, SBS | 15.54747% | 11.74621% | 6,401,273 | 18,717,485 | 25,118,758 | 1,773,222,000 | 1.417 |
| OS-I, OS-II | 1.01615% | 0.08803% | 418,374 | 140,275 | 558,649 | 111,141,000 | 0.503 |
| OS-III | 0.41492% | 0.27815% | 170,833 | 443,230 | 614,063 | 45,381,000 | 1.353 |
| TOTAL | 100.00000% | 100.00000% | $41,172,439 | $159,349,145 | 200,521,584 | 11,033,990,000 | 1.817 |

Notes:
(1) From Schedule 6P, Col 8
(2) From Schedule 6P, Col 9
(3) Col 1 x Total Energy $ from Schedule 1P, line 5
(4) Col 2 x Total Demand $ from Schedule 1P, line 5
(5) Col 3 + Col 4
(6) Projected KWH sales for the period January 2016 - December 2016
(7) Col 5 x 100 / Col 6

**Schedule 8P**
Page 1 of 1

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2016 - December 2016**

**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 | 710,379 | 36.4100 | 4.49 | 1.6348 | 1.6348 | |
| 2 | Short-Term Debt | 21,331 | 1.0933 | 0.27 | 0.0030 | 0.0030 | |
| 3 | Preferred Stock | 79,362 | 4.0676 | 6.14 | 0.2498 | 0.4067 | |
| 4 | Common Stock | 713,646 | 36.5774 | 10.25 | 3.7492 | 6.1037 | |
| 5 | Customer Deposits | 21,109 | 1.0819 | 2.40 | 0.0260 | 0.0260 | |
| 6 | Deferred Taxes | 403,636 | 20.6881 | | | | |
| 7 | Investment Tax Credit | 1,592 | 0.0816 | 7.31 | 0.0060 | 0.0086 | |
| 8 | Total | 1,951,055 | 100.0000 | | 5.6688 | 8.1828 | 0.6819 |
| | ITC Component: | | | | | | |
| 9 | Debt | 710,379 | 47.2519 | 4.49 | 2.1216 | 0.0017 | |
| 10 | Equity-Preferred | 79,362 | 5.2789 | 6.14 | 0.3241 | 0.0004 | |
| 11 | -Common | 713,646 | 47.4692 | 10.25 | 4.8656 | 0.0065 | |
| 12 | | 1,503,387 | 100.0000 | | 7.3113 | 0.0086 | |
| | Breakdown of Revenue Requirement Rate of Return between Debt and Equity: | | | | | | |
| 13 | Total Debt Component (Lines 1, 2, 5, and 9) | | | | | 1.6655 | 0.1388 |
| 14 | Total Equity Component (Lines 3, 4, 10, and 11) | | | | | 6.5173 | 0.5431 |
| 15 | Total Revenue Requirement Rate of Return | | | | | 8.1828 | 0.6819 |

Column:
(1) Based on the May 2015 Surveillance Report, Schedule 4.
(2) Column (1) / Total Column (1)
(3) Based on the May 2015 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

# 28

# FPL's Responses to Staff's First Set of Interrogatories, Nos. 1-8

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 28
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's First Set of Interrogatories, Nos. 1-8. [Bates

**Q.**

**On page 13, witness Keith testifies that FPL became aware of a limited window of opportunity to make use of low salinity water with the next opportunity not available until June 2015 at the earliest. Please explain what the limiting factors are with respect to FPL's window of opportunity to make use of low salinity water.**

**A.**

The "limited window" is based on the South Florida Management District's ("SFWMD") rules for consumptive use of surface waters. The SFWMD allows permitted withdrawals from regional surface canals only during the South Florida rainy season, normally June 1 to October 15 of each year as defined by the SFWMD. FPL applied for, and was granted permission for consumptive use of a local surface water canal until October 15, 2014. The next opportunity for such consumptive use did not become available until June 1, 2015. The water was of low salinity and significantly aided managing salinity in the cooling canal system.

**Q.**

**On page 10, witness Keith testifies that the variance for Project 33 is "primarily due to baghouse overhaul costs that were not included in the 2014 projection." Was the overhaul of the baghouse previously planned? If no, what caused the need for the overhaul?**

**A.**

The outage for the overhaul of the baghouse on Scherer Unit 4 was planned to occur in 2014 but the costs for the outage were inadvertently omitted from the Project 33 projections for 2014.

**Q.**

**On pages 10-11, witness Keith testifies that the variance for Project 35 is primarily due to an increase in monthly charges to clean nano-scale filters and the inadvertent exclusion of annual fees for activated carbon. How much of the total variance ($9,389) was associated with the increase in monthly charges to clean nano-scale filters?**

**A.**

Of the $9,389 variance, the amount associated with the monthly increase to clean nano-scale filters was $4,500 (an additional $450/month x 10 months).

**Q.**

**On page 11, witness Keith testifies that the variance for Project 38 was partially due to a reduction in staffing. Is the reduction in staff permanent?**

**A.**

No. The staffing level for the solar site has not been reduced; the site had two vacancies that took several months to fill. Both were filled by July of 2014 and the site was at full staffing through the end of 2014.

**Q.**

**On page 12, witness Keith states:**

**Based on the data collected under this monitoring program, the FDEP, in consultation with SFWMD and Miami Dade County ("MDC"), developed a draft Administrative Order ("AO") that was first shared with FPL for comments in the Summer of 2014 and Fall of 2014. The draft and, ultimately, the final AO that was issued by the FDEP on December 23, 2014, directed FPL to reduce salinity in the [Cooling Canal System] and identified a series of potential measures that FPL could include in its Salinity Management Plan.**

**a. Please provide a description of the potential measures, that FPL could include in its Salinity Management Plan, identified in the Final Administrative Order.**

**b. Is FPL currently in compliance with the Final Administrative Order?**

**c. If no, when does FPL anticipate being in compliance with the Final Administrative Order?**

**A.**

a. The AO provides a non-exclusive list of options in paragraph 37.d., as follows:

"The Management Plan may propose options, or combination of options, for reducing the salinity of the CCS. Among the options, FPL may propose to: 1) utilize the existing unused allocation of water for Unit 5 from the Floridan aquifer; 2) license and construct new Floridan wells; 3) utilize water from the L-31E canal consistent with District water reservation and consumptive use rule criteria; 4) utilize water from the Card Sound Canal consistent with Department and District rule criteria; 5) remove organic and sediment biomass within the CCS, and/or 6) remove hypersaline water from within and/or beneath the CCS through use of an Underground Injection Control ("UIC") well."

b. Administrative challenges were filed in opposition to the AO, which tolls the AO's effect. Compliance is deferred until the administrative challenges are resolved.

c. Compliance with the final AO will begin once it is made effective by the results of the currently ongoing administrative proceeding. A DOAH hearing is currently set for August 4-7, 2015. Assuming that the AO is finalized without revision at the conclusion of the administrative proceeding, FPL will file the Salinity Management Plan required by the AO within 90 days of the AO becoming final, which will be designed to achieve the required salinity reduction in the CCS within the two years allowed by the AO.

**Q.**

**On page 13, witness Keith testifies that storm water is an exceptionally cost-effective means of salinity reduction. Did FPL perform an economic analysis evaluating the use of storm water as a means of salinity reduction?**

**a. If yes, please provide the results of FPL's economic analysis.**

**b. If no, please explain why not.**

**A.**

FPL reviewed multiple options for providing cost-effective salinity reduction of the CCS. The decision criteria included cost and timeliness of access. Excess stormwater was immediately available, whereas other sources had significantly longer development timelines.

Excess storm water, readily available during certain times of the year, and requiring a limited pumping system, could provide up to 100 million gallons per day for the $3.4 million expended.

Use of these readily available and proximate resources is generally more cost effective than use of degraded water sources that require extensive treatment and/or significant delivery systems (pumps and pipes).

For comparison, FPL is also seeking approvals to install 5 Upper Floridan Aquifer ("UFA") wells to provide up to 14 million gallons per day of water that has higher salinity than the storm water, for an estimated $13 million cost. While these wells will be an important contributor to achieving the required salinity reduction in the CCS, the use of storm water is clearly a more cost-effective alternative to the extent available. FDEP approved the Site Certification Modification for the UFA well project, but it was challenged and is in an Administrative Proceeding to resolve.

**Q.**

**On page 13, witness Keith testifies that equipment failures associated with Project 45 were covered under warranty. How much would equipment failures, which occurred during 2014, cost if the failures weren't under warranty?**

**A.**

There were no ESP equipment failures in 2014. The statement should have said… "any equipment failures would have been covered under warranty".

**Q.**

**On page 15, witness Keith testifies that the variance for Project 50 is primarily due to FPL's portion of the cost of studies conducted by Georgia Power Company. Please explain how FPL's portion of the costs was determined.**

**A.**

Steam Effluent Guidelines cost studies common to Plant Scherer are allocated in a two-step process. First, 25% is allocated to each of the 4 operating units. Secondly, the 25% unit cost is allocated to each owner based on its unit ownership percentage. FPL is 76.36% owner of Unit 4 therefore the portion of the study costs common to Plant Scherer allocated to FPL is 25% times 76.36% or 19.09%.

**AFFIDAVIT**

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 18th day of JUNE, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Ron Hix, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 8 from Staff's First Set Of Interrogatories to Florida Power & Light Company (Nos. 1-8) in Docket No. 150007-EI, and that the response is true and correct based on his personal knowledge.

Ronald Hix

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18th day of JUNE, 2015.

Notary Public
State of Florida, at Large

Notary Public State of Florida
Lois M Sivia
My Commission EE130697
Expires 11/05/2015

My Commission Expires:
11-5-15

**AFFIDAVIT**

STATE OF FLORIDA )

COUNTY OF PALM BEACH )

I hereby certify that on this 23 day of June, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Roxane Kennedy, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatories numbers 2, 3, 4 and 7 from **Staff's First Set Of Interrogatories to Florida Power & Light Company (Nos. 1-8)** in Docket No. 150007-EI, and that the responses are true and correct based on her personal knowledge.

Roxane Kennedy

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 23 day of June, 2015.

Notary Public
State of Florida, at Large

My Commission Expires:

KATHLEEN L. HALL
MY COMMISSION # EE 222600
EXPIRES: December 5, 2016
Bonded Thru Notary Public Underwriters

**AFFIDAVIT**

~~STATE OF FLORIDA~~ )
District of Columbia
~~COUNTY OF PALM BEACH~~ )

I hereby certify that on this 24th day of June, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven D. Scroggs, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatories numbers 1, 5 and 6 from **Staff's First Set Of Interrogatories to Florida Power & Light Company (Nos. 1-8)** in Docket No. 150007-EI, and that the responses are true and correct based on his personal knowledge.

Steven D. Scroggs

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24th day of June, 2015.

LINDA C. BROWN NOTARY PUBLIC EXP. 8-31-2016 DISTRICT OF COLUMBIA

Notary Public
~~State of Florida, at Large~~

LINDA C. BROWN
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires August 31, 2016

My Commission Expires:

# 29

# FPL's Responses to Staff's Second Set of Interrogatories, Nos. 10-18

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 29
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's Second Set of Interrogatories, Nos. 10-18.

**Q.**

**The following questions refer to Witness Keith's July 31, 2015, testimony.**

**On page 4, regarding Project 5a, the witness testifies that, "FPL is implementing the use of a new work management system."**

**a. What is the cost of the new work management system being implemented by FPL?**

**b. Will the described work management system be used for projects other than Project 5a? Please explain.**

**A.**

a. The new work management system is associated with all FPL production assets. None of the costs for this system are being charged to the ECRC.

b. Yes. Fuel oil storage tanks are but one asset type that will be managed through this system. All of FPL's Power Generation assets and equipment will utilize the Maximo system (work management system) to manage daily work and longer term scheduled work such as the fuel storage tank inspection program.

**Q.**

**On page 7, regarding Project 23, the witness testifies that, "there was a staffing reduction of one full time and one part time position." How much of the lower than expected expenditures are associated with the described staffing reduction?**

**A.**

The staffing reduction was responsible for expenditures being $24,651 lower than expected.

**Q.**

**On page 8, regarding Project 30, the witness testifies that the expenditure "variance is primarily associated with replacement of gauges at each station on the Little Manatee River." What prompted the gauge replacement?**

**A.**

In order to continue obtaining accurate data to comply with the project's monitoring requirements, FPL needed to replace the 10 year old monitors that were at the end of their useful life. The portion of the wooden structures and supports were in poor condition and needed to be removed and replaced with new pressure treated wood. The barnacle crusted PVC needed to be removed. The structures that held the data sondes equipment were failing. The staff gauges were not providing any data at the lower elevations.

**Q.**

**The following questions refer to Witness Labauve's July 31, 2015, testimony.**

**For the proposed Coal Combustion Residual project, please describe how FPL developed its estimated capital expenditures and estimated O&M expenses. Please include a list and description of sources relied on for each estimate.**

**A.**

Estimates of capital expenditures were provided by the operating agents, Georgia Power Corporation ("GPC") and St John's River Power Park ("SJRPP"). Preliminary estimates prepared by GPC staff and consultants were based on task and action plans for compliance with the new rule's requirements for demonstrations and certifications for continued use or forced closure of the CCR management units (impoundments and landfills). FPL reviewed the approach and cost estimate for consistency with general industry expectations and practices. FPL's ownership share was calculated from these estimates.

**Q.**

**On page 8, the witness testifies that, "FPL's preliminary estimate for its ownership share of capital investment costs associated with the CCR Project for both Plant Scherer and SJRPP combined is approximately $8 million."**

**a. Please describe how FPL developed the $8 million estimate described by witness Labauve. Also, please identify any sources relied on to develop the $8 million estimate.**

**b. Please identify how much of the $8 million is associated with activities at Plant Scherer and SJRPP respectively.**

**c. Has FPL incurred any costs associated with the CCR project in 2015? If yes, please state the amount.**

**d. Does FPL anticipate incurring any costs associated with the CCR project in 2015? If yes, please state the anticipated amount.**

**A.**

a. Estimates used by FPL were provided by the operating agents GPC and SJRPP for the respective plants. The FPL estimate of $8 million reflects FPL's ownership share of the total estimated project costs provided by the operating agents of each facility.

b. The $8 million estimate assumes that Plant Scherer may and SJRPP will be able to demonstrate compliance with the new regulatory performance standards to continue the use of the existing unlined management units. The estimate associated with the new requirements for the Plant Scherer impoundment and management units without early closure is $7.5 million. The estimate associated with the new requirements for the landfill and other management units at SJRPP is $0.5 million.

c. No costs have been incurred in 2015 to date.

d. FPL does not anticipate any costs associated with the CCR project in 2015.

**Q.**

**On page 8, the witness testifies that proposed activities, associated with the CCR Project, "include engineering studies, plan development, CCR transport system modifications, groundwater monitoring well design, monitoring well installation and periodic monitoring, and new CCR waste management unit design."**

**a. Please provide a cost estimate for each activity identified above.**

**b. Please discuss why FPL considers the described activities as capital investment costs.**

**A.**

a. The activities are either specific requirements from the new CCR Rule or will be required modifications to plant systems in order to comply with the design requirements of the new CCR Rule. FPL has been provided broad category estimates developed by Georgia Power Corporation and their consultants and general plan structure for the CCR management activities, but not individual activity costs.

The use of a landfill for management of coal ash and other CCR at SJRPP reduces the complexity and number of engineering demonstrations required under the new CCR Rule. The initial estimates for FPL's share to address the unlined landfill and CCR systems at SJRPP may be allocated to the requested activity elements as follows:

- Engineering studies of plant CCR management systems and units -- $16,000
- Plan development -- $8,300
- CCR transport modifications -- $30,000
- Groundwater monitoring well design -- $2,600
- New monitoring well installation and periodic monitoring -- $5,900
- New lined CCR waste management landfill development -- $430,000

b. The new CCR Rule requires these activities to extend throughout the life of the existing units or the initiation of early retirement and construction of new replacement capacity (landfill) that will meet the new design requirements established in the Rule. The landfill, water monitoring wells, and the pond are all retirement units currently listed in the property retirement unit catalog. Any costs directly or functionally related to the installation and removal of a retirement unit is capital. Early retirement of the Plant Scherer pond and construction of new capacity will require the additional $42 million referenced in previous testimony for final closure of the existing units and construction of new units.

**Q.**

**On page 9, the witness testifies that,**
**In the event the ash impoundment at Plant Scherer is forced to enter preliminary closure requiring conversion to full dry ash management and construction of dry ash storage, FPL's ownership share of associated costs are projected to be $42 million.**

**a. Please describe how FPL developed the $42 million estimate discussed by witness Labauve. Also, please identify any sources relied on to develop the $42 million estimate.**

**b. Please discuss the anticipated activities associated with the preliminary closure of the ash impoundment at Plant Scherer.**

**A.**

a. Estimates used by FPL were provided by the operating agent Georgia Power Corp. The FPL estimate of $42 million reflects FPL's ownership share of the total estimated project costs ($200 million) provided by the operating agent.

b. At this time the closure plan required by the new CCR Rule has not been fully developed for the 550 acre ash impoundment (pond). If the pond does not meet requirements for continued use, the pond must cease receiving CCR and CCR wastewater within 6 months of the triggering event and begin closure. During the 6 month period alternate disposal will need to be developed. The closure is to be completed within 5 years, but closure may be extended an additional 10 years in two year increments. The pond may be closed with the CCR in place provided the free liquids are removed, the remaining CCR dewatered and stabilized sufficiently to support the final cover, the final cover system is installed to prevent infiltration, and drainage systems are installed to prevent ponding and erosion. Alternatively, the CCR may be removed and the former pond decontaminated as demonstrated by post removal testing and monitoring. The quantity of CCR in the pond was estimated in excess of 11 million cubic yards in December 2008. Closure of the existing pond will require construction of a new ash landfill and conversion to full dry ash management at the plant. The new landfill would include purchase of additional land, and construction of the landfill with prescribed liner system, monitoring wells and CCR transfer systems. This will require additional equipment installation to facilitate the removal of CCR that is currently managed through wet conveyance systems. Additionally, new wastewater treatment systems will be required for the management of those waste streams that were managed in the pond as co-disposal.

**Q.**

**On page 14, the witness testifies that, "FPL is projecting to spend approximately $231,000 in additional O&M expenses" for Project No. 28. Please describe the steps FPL will take to ensure that the costs incurred are prudent and reasonable.**

**A.**

The $231,000 of projected additional O&M costs is predominantly comprised of two activities:

1) Required inspections and modifications to the existing temporary conceptual horseshoe crab barrier (barrier) and;

2) Relocation of the horseshoe crabs that manage to get past the barrier and are retrieved from the intake course bar screens.

For both activities, contracts were issued utilizing standard practices to ensure that costs are prudent and reasonable.

For the first contract, a single source justification process was utilized. The vendor being utilized installed the existing barrier and therefore is most familiar with the design and the possible issues that might be observed during the inspections; as well as potential modifications that might improve the barrier's effectiveness.

A single source justification process was also utilized for the second contract. In this case, the vendor, who is relocating the horseshoe crabs, has bid competitively and has conducted extensive biological work at the Cape Canaveral Energy Center (CCEC) as well as many other FPL facilities. The vendor is familiar with the plant intakes and the surrounding areas of the Indian River Lagoon. In addition, the vendor has a Master Contract with FPL to do this type of work and during recent bidding for services to address the biological portion of the studies for the new 316 (b) Rule for existing facilities, was part of each bidder's team due to its expertise and cost effective operations.

FPL has worked with both vendors in the past, and each has a history of being efficient and cost-conscious. In summary, use of these vendors will give FPL the best chance for the most efficient and economical outcome.

**Q.**

**On pages 14 and 15, the witness testifies that, "FPL's capital investment costs for the concrete barrier are projected to be approximately $0.5 million.**

**a. Please describe how FPL developed the $0.5 million estimate described by witness Labauve and identify any sources relied on to develop the $0.5 million estimate.**

**A.**

In August 2014, FPL invited several companies to bid on a Request for Proposal to design and construct a permanent barrier to deter horseshoe crabs from entering the Cape Canaveral Energy Center's intake canal area. The lowest bid for construction of that permanent barrier was from UESI and was approximately $400,000. Not included in the bid was the cost of permitting, which historically adds approximately 5-10% to the cost of this type of project, or the potential need for design modifications.

Based on the original bid price of approximately $400,000, along with an additional, yet undetermined, cost of any required permitting and barrier modifications, the final cost was estimated to be approximately $500,000.

**AFFIDAVIT**

STATE OF FLORIDA )

COUNTY OF ~~PALM BEACH~~ Volusia )

I hereby certify that on this 24 day of September, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Jack Alexander, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 11 from **Staff's Second Set Of Interrogatories to Florida Power & Light Company (Nos. 10-18)** in Docket No. 150007-EI, and that the response is true and correct based on his personal knowledge.

Jack Alexander

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24 day of September, 2015.

Patricia A. Mulligan
Notary Public
State of Florida, at Large

PATRICIA A. MULLIGAN
MY COMMISSION # FF 064787
EXPIRES: November 15, 2017
Bonded Thru Notary Public Underwriters

My Commission Expires:
11-15-2017

**AFFIDAVIT**

STATE OF FLORIDA )

COUNTY OF PALM BEACH )

I hereby certify that on this 21 day of September, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Tomey Tuttle, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 13 through 16 from **Staff's Second Set Of Interrogatories to Florida Power & Light Company (Nos. 10-18)** in Docket No. 150007-EI, and that the response is true and correct based on his personal knowledge.

Tomey Tuttle

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 21st day of September, 2015.

Lois M Sivia
Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission EE130697
Expires 11/05/2015

**AFFIDAVIT**

STATE OF FLORIDA )

COUNTY OF PALM BEACH )

I hereby certify that on this 22nd day of September, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Roxane Kennedy, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 10 and 12 from **Staff's Second Set Of Interrogatories to Florida Power & Light Company (Nos. 10-18)** in Docket No. 150007-EI, and that the response is true and correct based on her personal knowledge.

Roxane Kennedy

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 22nd day of September, 2015.

Notary Public
State of Florida, at Large

My Commission Expires:
August 3, 2019

BRENDA THEROFF
MY COMMISSION # FF905959
EXPIRES August 03, 2019
(407) 398-0153 FloridaNotaryService.com

**AFFIDAVIT**

STATE OF FLORIDA )

COUNTY OF PALM BEACH )

I hereby certify that on this 21st day of September, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Ron Hix, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 17 and 18 from **Staff's Second Set Of Interrogatories to Florida Power & Light Company (Nos. 10-18)** in Docket No. 150007-EI, and that the response is true and correct based on his personal knowledge.

Ronald Hix

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 21st day of September, 2015.

Lois M Sivia
Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission EE130897
Expires 11/05/2015

# 30

# FPL's Responses to Staff's Third Set of Interrogatories, Nos. 19-21

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 30
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's Third Set of Interrogatories, Nos. 19-21.

**Q.**

**On page 11 of witness Randall LaBauve's testimony, filed August 31, 2015, the witness identifies TPCCMP activities that FPL expects to undertake in 2016. Please provide the projected cost of each activity listed.**

**A.**

FPL will continue to conduct the monitoring and reporting requirements of the TPCCMP, including data collection and publication of periodic reports. FPL estimated that it will incur $1.5 million in 2016.

FPL plans to continue to pump water from the three wells completed in 2015 and also anticipates being able to receive excess stormwater from the L-31 canal. FPL estimated that it will incur $1 million in 2016.

The permits that allow for the use of the excess stormwater from the L- 31 contain a number of requirements that FPL is obligated to execute, including ground and surface water sampling as well as administrative requirements to monitor and document water flow from the L-31 canal, which will need to be addressed in 2016. FPL estimated that it will incur $500,000 in 2016.

FPL plans to install the Upper Floridan Aquifer wells at Turkey Point, once the administrative challenge to that work is resolved. FPL estimated that it will incur $6.8 million in 2016.

FPL plans to continue the CCS sediment removal. FPL estimated that it will incur $25 million in 2016.

**Q.**

**On page 3 of witness Terry Keith's testimony, filed August 31, 2015, the witness testifies that Form 42-5P "provides the description and progress of approved environmental projects included in the projected period." For each project identified in Form 42-5P with an estimated fiscal expenditure greater than $50,000, please provide a summary of activities that are expected to be performed in 2016.**

**A.**

Please see Attachment I.

# O&M Projects

**Project 1: Air Operating Permit Fees**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $273,565. The monthly fees for 2015 emissions will be paid during the 2016 time period. Year 2015 air operating permit fees for the Florida facilities are calculated in January 2016 utilizing 2015 operating information. Fees will be paid to the Florida Department of Environmental Protection on March 2016.

**Project 3a: Continuous Emission Monitoring Systems ("CEMS")**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $591,966. Operation and maintenance of the CEMS will continue in 2016 in accordance with the requirements of the CEMS Quality Assurance ("QA") Program Manual as well as training on the operation and maintenance of the system.

**Project 5a: Maintenance of Stationary Above Ground Fuel Storage Tanks**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $213,583. Work will continue on miscellaneous maintenance of above ground fuel storage tanks and piping systems. All required API 653 external inspections will continue through 2016 and all 2016 tank registration fees will be paid in May of 2016. PTF tank #1 and PTF5 L/O (Light Oil) are due for API external inspection. PMR Start-up tank, WCEC tanks 1 & 2, and TMR tank 1273 is due in 2016 for touch-up painting. TMT tank 1272 is due for complete coating in 2016.

**Project 8a: Oil Spill Clean-up**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $257,829. These cost projections are associated with inspection and maintain oil spill response equipment at all of the OPA 90 sites as well as support for required tabletop and deployment drill exercises at the various sites and corporate response plan.

**Project 14: NPDES Permit Fees**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $69,200. 2015 yearly permit fees will be paid to the FDEP for power generation operating plants and nuclear plants. The payment is due January 2016.

**Project 19a, 19b: Substation Pollutant Discharge Prevention & Removal**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are:

19a $2,734,611

19b $1,006,105

Estimated expenditures for the prevention and removal of substation pollutant discharges are based on historical clearances for both Transmission and Distribution transformers.

**Project 21: St. Lucie Turtle Net**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $110,000, related to inspections and net cleaning in order to remove algae and jellyfish buildup to maintain the effectiveness of the net in avoiding sea turtle fatalities.

**Project 22: Pipeline Integrity Management**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $196,500. The Dania Spur pipeline jet fuel 8" line is due for inline inspection. Additionally, there will be some confirmatory/repair digs on the Terminal Manatee and Terminal Martin pipelines.

**Project 23: Spill Prevention Control and Countermeasures ("SPCC")**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $975,871. Power Generation and Delivery projects for 2016 will include updates to Facility Response Plans ("FRP") for the Turkey Point fossil unit. Additionally, new CT's at the Lauderdale plant will require revisions to the FRP and SPCC plan. The installation of a coalescing filter at Martin is planned. Evaluation and subsequent repairs of secondary containment is underway at Martin metering tanks and will be performed at Manatee Terminal.

Transmission and Substation projects for 2016 will include quarterly compliance inspections of all substation facilities, SPCC administrative program oversight, and creation of SPCC plans for new facilities, amendment of current SPCC plans as required for updated facilities and equipment, and repairs performed for broken curbing or oil diversionary structures.

**Project 24: Manatee Reburn**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $191,795. Projected activities for 2016 include installation of a platform on the fourth burner deck on Manatee Units 1 and 2. Additionally, there is a planned replacement of all burner gas valves on Manatee Unit 2.

**Project 27: Lowest Quality Water Source**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $144,000. The projected activities for 2016 include the cost of running the system and included chemicals. These costs are based on the amount of water processed from the cooling pond, which is the source of lowest quality water.

**Project 28: CWA 316(b) Phase II Rule**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $520,780. These expenditures are primarily associated with the implementation of studies required by the 316 (b) Existing Facilities Rule along with required inspections, maintenance, and other activities associated with the Cape Canaveral Plant temporary horseshoe crab barrier.

**Project 29: SCR Consumables**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $476,279. Planned activities at the Martin Plant are for ammonia purchases, inspections of two of the SCR systems (Unit 8B & 8D), and ammonia flow control valve actuator overhauls (Unit 8B, 8C, & 8D)

**Project 31: CAIR**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $7,168,062, primarily for the operation and maintenance of the FGD and SCR on Scherer Unit 4.

**Project 33: MATS Project**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $3,018,075, primarily for the operation and maintenance of the baghouse and sorbent injection system on Scherer Unit 4.

**Project 37: Desoto Solar**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $897,458 associated with the following activities:

- Payroll, training and benefits for De Soto's allocated share of Engineers and an increase in staffing to fill a position that was left vacant in March 2015
- Material purchases in support of reliability task and preventative maintenance
- Operation and Maintenance of new building which includes; utilities, cleaning services, AC maintenance, pest control and trash pickup
- Outside contractor services, which include breaker maintenance, Inverter maintenance, tracker lubrication and inspection, and other contractor services
- Vegetation management and landscaping of the 360 acre property
- Purchases and licenses for PI and Wonderware software used for remote monitoring and control at the site. Planned technical fleet team support payroll and expenses

**Project 38: Space Coast Solar**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $288,893, associated with the following:

- Payroll, training and benefits for Space Coast's allocated share of Engineers
- Material and parts for the site in support of reliability tasks and preventative maintenance
- Operating and maintenance for office building, which will include cleaning services, AC maintenance, pest control and trash pickup
- Outside contractor services which include inverter maintenance and other contractor services
- Vegetation management and landscaping of the 60 acre property
- Purchases and licenses for PI and Wonderware software
- Lodging, vehicle utilization, meals and other travel expenses

- Planned technical fleet team support payroll and expenses

**Project 39: Martin Next Generation Solar Energy Center**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $3,754,487, associated with the following:

- Payroll, training and benefits for Martin Solar's allocated share of Engineers
- Materials and parts for the site in support of reliability tasks and preventative maintenance
- Vehicle maintenance which includes routine repairs and maintenance
- Outside services from contracted work that includes Mirror Frame Support Arm repairs, Field Ball Joint Bracket installations and mirror washing services

**Project 40: Greenhouse Gas Reduction Program**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $79,000. The primary environmental activity will be for technical development of the States Implementation Plan ("SIP"). The Clean Power Plan will be final in December 2015 and then the state will be required to start development of their SIP. Most of that effort will occur in the spring with some activity continuing on through the summer as they near the deadline for their September submittal.

Expenditures will include modeling impacts of various scenarios and legal assistance.

Development of the SIP is the crucial template for how Florida will implant the rule and will determine how FPL is treated during implementation. The SIP will likely have significant impact to our costs in the future.

**Project 41: Manatee Temporary Heating System**

Estimated project fiscal expenditures for January 2016 through December 2016 are $1,886,820. This amount is primarily associated with relocating the manatee heating area and removing the existing barrier wall in the plant intake (part of the existing manatee heating area) at the Cape Canaveral Energy Center.

**Project 42: Turkey Point Cooling Canal Monitoring Plan**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $28,001,800. FPL will continue to conduct the monitoring and reporting requirements of the TP CCM Plan, including data collection and publication of periodic reports. CCS sediment removal will continue in order to redistribute CCS flows in order to improve the heat exchange efficiency. This results in a lower overall CCS temperature, and therefore a lower evaporation rate contributing to a lower CCS salinity. The sediment removal also improves the hydraulic connection between the CCS and underlying groundwater, an important element of the overall salinity-reduction effort. Additionally, the L-31 permit contains a number of requirements that FPL is obligated to execute, including ground and surface water sampling as well as many administrative requirements to monitor and document water flow from the L-31 canal system when it is being pumped in the CCS.

**Project 45: 800MW Unit ESP Project**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are expected to be $1,205,861 primarily for the routine maintenance of the Martin and Manatee 800 MW ESPs.

**Project 47: NPDES Permit**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $57,898, associated with Whole Effluent Toxicity testing that is required in the NPDES permits for Cape Canaveral, Ft. Myers, Lauderdale, Port Everglades, Riviera and St. Lucie plants.

**Project 48: Industrial Boiler MACT Project 48: Industrial Boiler MACT – O&M**

Estimated project fiscal expenditures for the period January 2016 through December 2016 are $52,500, associated with the annual tune-up of boilers and process heaters at West County and Martin Terminal.

# CAPITAL PROJECTS

**Project 2b: Low NOX Burner Technology**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $100,923. There are no new capital expenditures planned for the 2016 period. Projected expenditures are related to depreciation and return on existing investment.

**Project 3b: CEMS**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $507,575. There are no new capital expenditures planned for the 2016 period. Projected expenditures are related to depreciation and return on existing investment.

**Project 5b: Maintenance of Stationary Above Ground Fuel Storage Tanks**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $1,546,673. There are no new capital expenditures planned for the 2016 period. Projected expenditures are related to depreciation and return on existing investment.

**Project 8b: Oil Spill Clean Up**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $148,938. In 2016, FPL intends to replace two (2) Oil Spill Response Boats; one at Ft. Lauderdale Plant and one at Manatee Plant. FPL will also be constructing a boat ramp at the Port of Manatee to allow for Spill Response equipment to be launched from vicinity closer to the Manatee Fuel terminal. This addition will allow FPL to respond timely safely and efficiently. Ft. Lauderdale will be installing a boat lift to allow for safe deployment of the spill response boat.

**Project 20: Wastewater Discharge Elimination & Reuse**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $76,974. There are no new capital expenditures planned for

the 2016 period. Projected expenditures are related to depreciation and return on existing investment.

**Project 21: St. Lucie Turtle Net**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $783,701. There are no new capital expenditures planned for the 2016 period. Projected expenditures are related to depreciation and return on existing investment.

**Project 22: Pipeline Integrity Management**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $307,123. There are no new capital expenditures planned for the 2016 period. Projected expenditures are related to depreciation and return on existing investment.

**Project 23: SPCC (Spill Prevention, Control, and Countermeasures)**

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $1,845,303. Construction of 46,000 gallon collection basin will continue at Turkey Point and it is expected to be complete in 2016.

**Project 24; Manatee Reburn**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $3,074,050. FPL plans on installing a burner deck platform above the 4th burner deck on both Manatee Plant Units 1 and 2.

**Project 25: Pt. Everglades EPS Tech**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $16,757,728. There are no new capital expenditures planned for the 2016 period. Projected expenditures are related to depreciation and return on existing investment.

**Project 31: CAIR Compliance**

Estimated project fiscal expenditures (depreciation and return) for the period January 2016 through December 2016 are $56,597,147. Project additions in 2016 include the modification of FGD reagent storage and handling area and catalyst replacement at Plant Scherer.

**Project 33: MATS**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $11,407,958. In 2016, Scherer will install a new pugmill with dust collector for Powder Activated Carbon.

**Project 36: Low-Level Radioactive Waste Storage**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $1,854,128. There are no new capital expenditures planned for the 2016 period. Projected expenditures are related to depreciation and return on existing investment.

**Project 37: Desoto Solar**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $15,375,753. There are no new capital expenditures planned for the 2016 period. Projected expenditures are related to depreciation and return on existing investment.

**Project 38: Space Coast Solar**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $7,219,202. There are no new capital expenditures planned for the 2016 period. Projected expenditures are related to depreciation and return on existing investment.

**Project 39: Martin Next Generation Solar Energy Center**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $44,503,043. FPL's 2016 capital expenditures include

replacement of Solar Tube and Mirrors, Digital Ovation Control Upgrades, and a Solar Field 1 Culvert Upgrade.

**Project 41: Manatee Temporary Heating System**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $448,084. There are no new capital expenditures planned for the 2016 period. Projected expenditures are related to depreciation and return on existing investment.

**Project 42: Turkey Point Cooling Canal Monitoring Plan**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $999,521. Pending the outcome of the administrative challenge, FPL will incur costs to install the Upper Floridan Aquifer ("UFA") and saline water wells at Turkey Point.

**Project 45: 800 MW Unit ESP**

Estimated project fiscal expenditures (depreciation and return) for January 2016 through December 2016 are expected to be $24,235,887. The Manatee plant plans to replace reburn burner deck gas valves and A/C replacement Units 1 and 2.

**Q.**

**Please restate the data in Exhibit TJK-3 of witness Terry Keith's August 31, 2015, testimony at Form 42-7P (appendix I, Page 111) to reflect FPL's proposed 2016 ECRC factors in cents/kWh.**

**A.**

Please see Attachment I.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF ENVIRONMENTAL COST RECOVERY CLAUSE FACTORS

JANUARY 2016 THROUGH DECEMBER 2016

| (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 | 54.20416% | 59.09185% | 57.85852% | 45,578,425 | 108,331,215 | 1,820,063 | 155,729,724 | 59,217,744,919 | 0.263 |
| GS1/GST1/WIES1 | 5.46339% | 5.56092% | 5.75989% | 4,593,978 | 10,194,852 | 181,192 | 14,969,821 | 5,968,723,003 | 0.251 |
| GSD1/GSDT1/HLFT1 | 23.59568% | 21.59465% | 21.51961% | 19,840,801 | 39,588,783 | 676,959 | 60,106,543 | 25,780,251,707 | 0.233 |
| OS2 | 0.00962% | 0.00722% | 0.04311% | 8,091 | 13,239 | 1,356 | 22,686 | 10,815,998 | 0.210 |
| GSLD1/GSLDT1/CS1/CST1/HLFT2 | 9.70787% | 8.83336% | 9.10071% | 8,163,015 | 16,193,913 | 286,285 | 24,643,213 | 10,617,262,134 | 0.232 |
| GSLD2/GSLDT2/CS2/CST2/HLFT3 | 2.31458% | 1.75902% | 1.77888% | 1,946,248 | 3,224,750 | 55,959 | 5,226,957 | 2,553,194,139 | 0.205 |
| GSLD3/GSLDT3/CS3/CST3 | 0.14411% | 0.11046% | 0.13230% | 121,181 | 202,509 | 4,162 | 327,852 | 163,603,794 | 0.200 |
| SST1T | 0.07433% | 0.04869% | 0.17248% | 62,502 | 89,258 | 5,426 | 157,186 | 84,383,182 | 0.186 |
| SST1D1/SST1D2/SST1D3 | 0.01248% | 0.01050% | 0.02116% | 10,496 | 19,252 | 666 | 30,414 | 14,030,773 | 0.217 |
| CILC D/CILC G | 2.51334% | 1.91456% | 1.84631% | 2,113,385 | 3,509,897 | 58,080 | 5,681,363 | 2,774,212,820 | 0.205 |
| CILC T | 1.19151% | 0.85585% | 0.67034% | 1,001,900 | 1,569,006 | 27,379 | 2,598,285 | 1,352,648,209 | 0.192 |
| MET | 0.08061% | 0.07461% | 0.07768% | 67,782 | 136,778 | 2,444 | 207,004 | 90,613,286 | 0.228 |
| OL1/SL1/PL1 | 0.58363% | 0.06765% | 0.75182% | 490,751 | 124,019 | 23,650 | 638,420 | 637,607,559 | 0.100 |
| SL2, GSCU1 | 0.10469% | 0.07068% | 0.06697% | 88,031 | 129,570 | 2,107 | 219,708 | 114,374,076 | 0.192 |
| | | | | | | | | | 0.000 |
| Total | | | | 84,066,585 | 183,326,841 | 3,145,748 | 270,559,175 | 109,379,465,607 | 0.247 |

[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, Column 2
[e] Total CP Demand $ from Form 42-1P, Line 5, Column 3
[f] Total GCP Demand $ from Form 42-1P, Line 5, Column 4
[g] Col 5 + Col 6 + Col 7
[h] Projected KWH sales for the period January 2016 through December 2016.
[i] Col 8 / Col 9 * 100

Note: There are currently no customers taking service on Schedules ISST1(D) or ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 Factor.

Totals may not add due to rounding.

**AFFIDAVIT**

STATE OF FLORIDA )

COUNTY OF PALM BEACH )

I hereby certify that on this 30th day of September, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Lisa Fuca, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory number 19 from **Staff's Third Set Of Interrogatories to Florida Power & Light Company (Nos. 19-29)** in Docket No. 150007-EI, and that the response is true and correct based on her personal knowledge.

Lisa Fuca

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of September, 2015.

Notary Public
State of Florida, at Large

My Commission Expires:

JO RETHA FORBES
Notary Public - State of Florida
My Comm. Expires Mar 8, 2018
Commission # FF 090102

**AFFIDAVIT**

STATE OF FLORIDA )

COUNTY OF PALM BEACH )

I hereby certify that on this 30th day of September, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Hampp, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 20 from **Staff's Third Set Of Interrogatories to Florida Power & Light Company (Nos. 19-29)** in Docket No. 150007-EI, and that the response is true and correct based on his personal knowledge.

John Hampp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of September, 2015.

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission EE130697
Expires 11/05/2015

**AFFIDAVIT**

STATE OF FLORIDA )

COUNTY OF MIAMI DADE )

I hereby certify that on this 30th day of September, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Damaris Rodriguez, who is personally known to me, and she acknowledged before me that she provided the answer to interrogatory number 21 from **Staff's Third Set Of Interrogatories to Florida Power & Light Company (Nos. 19-29)** in Docket No. 150007-EI, and that the response is true and correct based on her personal knowledge.

Damaris Rodriguez

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of September, 2015.

Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2018
Commission # FF 122975

# 31

# Commission Staff Final Audit Report for Florida Power & Light Company, Dated June 10, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 31
PARTY: STAFF
DESCRIPTION: Commission Staff Final Audit Report for Florida Power & Light Company,

FILED JUN 10, 2015
DOCUMENT NO. 03563-15
FPSC - COMMISSION CLERK

**State of Florida**

# Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

**-M-E-M-O-R-A-N-D-U-M-**

**DATE:** June 10, 2015

**TO:** Office of Commission Clerk

**FROM:** Lynn M. Deamer, Chief of Auditing, Office of Auditing and Performance Analysis

**RE:** Docket No.: 150007-EI
Company Name: Florida Power & Light
Company Code: EI802
Audit Purpose: Environmental Cost Recovery Clause
Audit Control No: 15-014-4-1

Attached is the final audit report for the Utility stated above. I am sending the Utility a copy of this memo and the audit report. If the Utility desires to file a response to the audit report, it should send a response to the Office of Commission Clerk. There is confidential work papers associated with this audit.

LMD/cp

Attachment: Audit Report

cc: Office of Auditing and Performance Analysis File

**State of Florida**

# Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Miami District Office

## Auditor's Report

Florida Power & Light Company
Environmental Cost Recovery Clause

**Twelve Months Ended December 31, 2014**

Docket No. 150007-EI
Audit Control No. 15-014-4-1
**June 5, 2015**

Bety Maitre
Audit Manager

Iliana H. Piedra
Audit Staff

Jeffery A. Small
Reviewer

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150007 Hearing Exhibits 00048

## Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Engineering in its audit service request dated January 14, 2015. We have applied these procedures to the attached summary exhibit and to several related schedules prepared by Florida Power & Light Company in support of its 2014 filing for the Environmental Cost Recovery Clause in Docket No. 150007-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.



150007 Hearing Exhibits 00049

## Objectives and Procedures

## General

Definition

Utility refers to the Florida Power & Light Company.
ECRC refers to the Environmental Cost Recovery Clause.

## Capital Investments

Utility Plant in Service

**Objectives:** The objectives were to verify a sample of ECRC project-related plant additions, retirements and adjustments for the period January 1, 2014, through December 31, 2014.

**Procedure:** We reconciled Plant in Service (Line 2) and Accumulated Depreciation (Line 3) to the general ledger for each capital project listed on the 2014 Form 42-8A. No exceptions were noted.

Construction Work in Progress

**Objective:** The objective was to verify net investments associated with the following capital projects, and to determine whether any project which involved the replacement or retirement of an existing plant asset is retired at the installed costs by the Utility in accordance with Rule 25-6.0142(4)(b), Florida Administrative Code.

1) CAIR Compliance No. 31
2) Martin Next Generation Solar Energy Center No. 39
3) 800MW Unit ESP Project No. 45

**Procedures:** We selected a sample of the additions to the capital projects for review. We determined whether additions had appropriate supporting documentation and were recorded to the correct project and account. We determined whether items that were replaced had a corresponding retirement. We reconciled Construction Work in Progress Non-Interest Bearing on Form 42-8A to the general ledger. No exceptions were noted.

## Revenue

Operating Revenues

**Objectives:** The objectives were to determine the actual Kilowatt Hours (KWH) sold for the period January 1, 2014, through December 31, 2014, and whether the Utility applied the Commission approved cost recovery factor to actual KWH sales.



150007 Hearing Exhibits 00050

**Procedures:** We reconciled the 2014 filing to the Utility's monthly Environmental Revenue Reports. We computed the factors by rate code and compared them to Order No. PSC-13-0687-FOF-EI, issued December 31, 2013. We selected a sample of residential and commercial customers' bills for the month of April 2014 and recalculated each to verify the use of the correct tariff rates for each of the clause audits of this Utility in Docket 150001-EI, Audit Control Number 15-023-4-2 . No exceptions were noted.

## Expense

Operation and Maintenance Expense

**Objectives:** The objectives were to verify that Operation and Maintenance (O&M) Expense listed on the Utility's Form 42-5A filing was supported by adequate documentation and that the expenses are appropriately recoverable through the ECRC.

**Procedures:** We traced expenses in the filing to the general ledger. We selected a sample of O&M Expenses. The source documentation for selected items was reviewed to ensure the expense was related to the ECRC, charged to the correct accounts, and in the correct amounts. No exceptions were noted.

Depreciation and Amortization

**Objective:** The objective was to verify that the most recent Commission approved depreciation rates or amortization periods were used in calculating Depreciation Expense.

**Procedures:** We recalculated Depreciation Expense on a test basis. We traced total year Depreciation Expense for each capital project listed on Form 42-8A to the general ledger detail. No exceptions were noted.

## Other Issues

$SO_2$ and $NO_X$ Emissions Allowances

**Objectives:** The objectives were to verify investments, inventory, expensed amounts, allowance auction proceeds and to verify amounts included in Working Capital, Form 42-8A.

**Procedures:** We traced the proceeds on the sales of emission allowances to the Environmental Protection Agency's payment coupons. We reviewed the inventory reported in the FERC forms and agreed the amounts to supporting documentation. We reconciled the gains in the ledger to the Working Capital calculation on Form 42-8A. We reviewed the Utility's procedure manual for treatment of the allowances and compared it to the general ledger. No exceptions were noted.



150007 Hearing Exhibits 00051

## True-Up

**Objective:** The objective was to determine if the True-Up and Interest Provision as filed on Form 42-2A was properly calculated.

**Procedures:** We traced the December 31, 2013, True-Up Provision to the Commission Order. We recalculated the True-Up and Interest Provision amounts as of December 31, 2014, using the Commission approved beginning balance as of December 31, 2013, the Financial Commercial Paper rates, and the 2014 ECRC revenues and costs. No exceptions were noted.

## Analytical Review

**Objective:** The objective was to perform an analytical review of the Utility's ECRC Revenues and Expenses to determine if there were any material changes or inconsistencies from the prior year.

**Procedures:** We compared 2014 to 2013 revenues and expenses. We requested explanations from the Utility for significant variances. Explanations provided were sufficient. Further follow-up was not required.



150007 Hearing Exhibits 00052

## Audit Findings

**None**



150007 Hearing Exhibits 00053

# Exhibit

## Exhibit 1: True-Up

FORM 42-2A

FLORIDA POWER && LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD
JANUARY 2014 THROUGH DECEMBER 2014

| | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. ECRC Revenues (net of Revenue Taxes) | $16,550,106 | $15,111,889 | $14,607,578 | $15,437,131 | $18,245,293 | $19,028,987 | $20,154,001 | $21,417,520 | $21,530,886 | $18,541,999 | $15,806,297 | $15,119,997 | $211,551,686 |
| 2. True-up Provision | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($197,075) | ($2,364,901) |
| 3. ECRC Revenues Applicable to Period (Lines 1+2) | $16,353,031 | $14,914,814 | $14,410,503 | $15,240,056 | $18,048,218 | $18,831,912 | $19,956,926 | $21,220,445 | $21,333,811 | $18,344,924 | $15,609,222 | $14,922,922 | $209,186,785 |
| 4. Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| a. O&M Activities (Form 42-5A, Line 9) | $1,899,774 | $1,588,779 | $1,949,688 | $2,201,463 | $1,752,182 | $2,022,853 | $1,912,310 | $2,233,320 | $1,945,736 | $1,250,098 | $1,810,899 | $6,320,897 | $26,888,000 |
| b. Capital Investment Projects (Form 42-7A, Line 9) | $15,300,072 | $15,352,097 | $15,388,398 | $15,496,828 | $15,478,124 | $15,414,274 | $15,297,279 | $15,313,360 | $15,313,254 | $15,311,269 | $15,289,285 | $15,324,128 | $184,278,369 |
| c. Total Jurisdictional ECRC Costs | $17,199,846 | $16,940,877 | $17,338,086 | $17,698,291 | $17,230,306 | $17,437,127 | $17,209,590 | $17,546,680 | $17,258,990 | $16,561,367 | $17,100,184 | $21,645,026 | $211,166,369 |
| 5. Over/(Under) Recovery (Line 3 - Line 4c) | ($846,815) | ($2,026,063) | ($2,927,583) | ($2,458,235) | $817,913 | $1,394,785 | $2,747,337 | $3,673,764 | $4,074,821 | $1,783,557 | ($1,490,962) | ($6,722,103) | ($1,979,584) |
| 6. Interest Provision (Form 42-3A, Line 10) | ($2) | ($69) | ($192) | ($378) | ($333) | ($223) | ($155) | $17 | $237 | $407 | $491 | $296 | $96 |
| 7. Prior Periods True-Up to be (Collected)/Refunded | ($2,364,901) | ($3,014,642) | ($4,843,699) | ($7,574,398) | ($9,835,936) | ($8,821,281) | ($7,229,645) | ($4,285,388) | ($414,532) | $3,857,601 | $5,838,640 | $4,545,244 | ($2,364,901) |
| a. Deferred True-Up (Form 42-1A, Line 7) [1] | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $2,661,563 | $0 |
| 8. True-Up Collected/(Refunded) (See Line 2) | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $197,075 | $2,364,901 |
| 9. End of Period True-Up (Lines 5+6+7+7a+8) | ($353,079) | ($2,182,136) | ($4,912,835) | ($7,174,373) | ($6,159,718) | ($4,568,082) | ($1,623,825) | $2,247,031 | $6,519,164 | $8,500,203 | $7,206,807 | $682,075 | ($1,979,488) |
| 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) | ($353,079) | ($2,182,136) | ($4,912,835) | ($7,174,373) | ($6,159,718) | ($4,568,082) | ($1,623,825) | $2,247,031 | $6,519,164 | $8,500,203 | $7,206,807 | $682,075 | ($1,979,488) |

[1] From FPL's 2013 Final True-up filed on April 1, 2014.

# 32

# Florida Power & Light Company notification of new environmental projects, dated July 1, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 32
PARTY: STAFF
DESCRIPTION: Florida Power & Light Company notification of new environmental
150007 Hearing Exhibits 00055

FILED JUL 01, 2015
DOCUMENT NO. 04052-15
FPSC - COMMISSION CLERK

**John T. Butler**
**Assistant General Counsel – Regulatory**
**Florida Power & Light Company**
**700 Universe Boulevard**
**Juno Beach, FL 33408-0420**
**(561) 304-5639**
**(561) 691-7135 (Facsimile)**
**John.Butler@fpl.com**

July 1, 2015

**-VIA ELECTRONIC FILING -**

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

**Re: Docket No. 150007-EI**

Dear Ms. Stauffer:

I enclose for electronic filing in the above docket Florida Power & Light Company's ("FPL") Preliminary List of New Projects to be Submitted for Cost Recovery.

If there are any questions regarding this transmittal, please contact me at (561) 304-5639.

Sincerely,

*s/ John T. Butler*
John T. Butler

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

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

| | |
|---|---|
| In re: Environmental Cost Recovery Clause | Docket No: 150007-EI<br>Filed: July 1, 2015 |

**FLORIDA POWER & LIGHT COMPANY'S PRELIMINARY LIST OF NEW PROJECTS TO BE SUBMITTED FOR COST RECOVERY**

Florida Power & Light Company herby submits the attached Preliminary List of New Projects to be Submitted for Cost Recovery.

Respectfully submitted this 1st day of July, 2015.

R. Wade Litchfield, Esq.
Vice President and
General Counsel
John T. Butler, Esq.
Assistant General Counsel – Regulatory
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Telephone: (561) 304-5633
Facsimile: (561) 691-7135

BY: *s/ John T. Butler*
John T. Butler
Fla. Bar No. 283479



150007 Hearing Exhibits 00057

**CERTIFICATE OF SERVICE**
**Docket No. 150007-EI**

**I HEREBY CERTIFY** that a true and correct copy of the foregoing has been furnished by electronic service this 1st day of July, 2015 to the following:

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By: *s/ John T. Butler*
John T. Butler
Fla. Bar No. 283479

Florida Power & Light Company
Environmental Cost Recovery
Docket No. 150007-EI
July 1, 2015

**PRELIMINARY LIST OF NEW PROJECTS TO BE SUBMITTED FOR COST RECOVERY**

**Project:** Coal Combustion Residual - SJRPP and Scherer

**Law/Regulation:**
On April 17, 2015 the U.S. Environmental Protection Agency ("EPA") published a final rule in the Federal Register setting standards to regulate the disposal of coal combustion residuals ("CCR") under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). The new rule is codified at 40 CFR 257. This rule applies to all CCR generated by electric utilities and independent power producers that fall within the North American Industry Classification System (NAICS) code 221112.

**Brief Description of Project:**
The new CCR rule is a self-implementing rule with an effective date of October 14, 2015 that will impact Plant Scherer and St. Johns River Power Park ("SJRPP"). FPL must demonstrate compliance with the rule's new location restrictions, safety standards and performance standards of all existing CCR impoundments and landfills. If compliance cannot be demonstrated then corrective action is required. The rule requires the closure of unlined surface impoundments that cannot meet the rule's dam safety, groundwater protection or location standards within a specified timeframe. Closure of the Plant Scherer ash impoundment would have to be initiated within six months if the pond failed to meet one of those specific requirements. For impoundments and landfills that continue to operate, the requirements include the development of a new groundwater sampling and monitoring with a corrective action plan which includes the installation of new monitoring wells at the waste boundary. Future expansion of existing waste management landfill units at SJRPP will be required to meet more stringent design and performance standards. These standards include new requirements to install double liner and monitoring systems. These new requirements will not impact Plant Scherer as Georgia already requires these activities for the landfills in place.

FPL projects it will incur capital costs of $8 million associated with its portion of the initial activities required for implementation and compliance with the rule at Plant Scherer and SJRPP. Activities associated with this estimate include installation and development of new monitoring wells, construction costs to meet the new lined landfill standards, and engineering evaluations and designs required to prepare for closure at both sites. In the event that the Plant Scherer ash impoundment is forced to enter closure, construction of a new lined landfill, conversion of equipment for full dry ash management, and dewatering and closure of the impoundment would add $42 million to cost projections for the project. FPL expects to begin incurring costs in August 2015 for monitoring wells and engineering studies. No O&M components for this project are expected until approximately 2023.



150007 Hearing Exhibits 00060

# 33

# DEF's Responses to Staff's First Set of Interrogatories, Nos. 1-4

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 33
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's First Set of Interrogatories, Nos. 1-4. [Bates
150007 Hearing Exhibits 00061

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environment Cost Recovery Clause DOCKET NO. 150007-EI

DATED: June 29, 2015

**DUKE ENERGY FLORIDA'S RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-4)**

Duke Energy Florida, Inc. ("DEF"), responds to Staff's First Set of Interrogatories to DEF (Nos. 1-4), as follows:

**INTERROGATORIES**

1. On page 3 of witness West's April 1, 2015, testimony, she states:

> The Cooling Water Intake-316(b) variance is $28,570 or 26% lower than projected due to the method used to allocate costs to analyze 316(b) compliance strategies at each affected Duke generating site. Duke intends to implement a consistent 316(b) compliance approach across its entire fleet of regulated units.

a. Please describe Duke's method, which caused the variance, used to allocate costs to analyze 316(b) compliance strategies.

**Answer:**

Cost assumptions for 316(b) compliance strategies for all applicable Duke Energy facilities were initially compiled based on estimated costs associated with standard compliance measures and general rule guidance. Fleet-wide 316(b) program costs were allocated to each Duke Energy generating facility based on estimated facility compliance costs as a percentage of total estimated compliance costs for all facilities. As facility-specific strategic plans were developed, life cycle costs of

select alternatives, site-specific NPDES permit compliance schedules, and inclusion of DEF priorities and future plans led to changes in 316(b) implementation timelines and potential compliance options for Florida facilities. As a result, allocation of fleet-wide costs were adjusted to reflect changes in schedules, effort, activities and deliverables associated with these facilities.

b. Please describe the compliance approach Duke intends to implement across its entire fleet of regulated units.

**Answer:**

The approach Duke Energy intends to implement across its entire fleet of regulated units is to focus on full compliance with applicable 316(b) requirements through the development of facility specific strategic plans. Those strategic plans will include all applicable submittal requirements; targeted entrainment and impingement compliance options; schedules of compliance; identification of decision and agency milestones; risk assessments; and plans for implementation that include key activities and timelines.

2. On page 4 of witness West's April 1, 2015testimony, she testifies that the variance for Project 17 was partially due to an increase in scope of the Mercury Characterization Study. Please explain why the scope of the Mercury Characterization Study was increased.

**Answer:**

DEF originally projected costs for the operation and analysis of sorbent trap monitoring systems which provided a single, average value for a given sampling period. Based on monitoring feedback, which showed continuing elevation of mercury emissions during the planning period, it was determined that continuous emissions monitoring systems (CEMS) were necessary to characterize the root cause of the elevated mercury emissions. This change, from sorbent traps to CEMS, was the scope change addressed in Witness West's testimony.

3. On page 3 of witness Swartz's April 1, 2015, testimony, he testifies that the variance for Project 7.4 is primarily attributable to lower than expected cost for CAIR Crystal River Project 7.4 - Base and higher than expected costs for CAIR Crystal River Project 7.4 - Energy.

a. Please explain what caused the lower than expected cost for CAIR Crystal River Project 7.4 - Base.

**Answer:**

Lower than expected cost for CAIR Crystal River Project 7.4 - Base is primarily driven by a $270 thousand decrease in labor due to lower burden rates offset by a $198 thousand increase as a result of a change in strategy to comply with FDEP wastewater permit requirements (as explained in the response to Question 4) and $52 thousand of maintenance work shifted from 2014 to 2015.

b. Please explain what caused the higher than expected cost for CAIR Crystal River Project 7.4 - Energy.

**Answer:**

Higher than expected CAIR Crystal River Project 7.4 - Energy cost is primarily attributable to a $1.5 million increase in ammonia expense due to a higher ammonia price and $680 thousand higher hydrated lime expenses driven by an increase in consumption, partially offset by $1.1 million in lower limestone expense due to less consumption and $830 thousand lower gypsum expense as a result of lower disposal volume and corresponding reduction in sales expense.

4. On page 3 of witness Swartz's April 1, 2015, testimony, he testifies that the variance for the CAIR Crystal River Project - Base is driven by a change in strategy to comply with FDEP wastewater permit requirements. What caused DEF to change its strategy to comply with FDEP wastewater permit requirements?

**Answer:**

Industry experience with deep-well injection and advances in other technologies changed critical assumptions that were used in DEF's original evaluation. In May 2013, an outside contractor studied five potential technologies for wastewater treatment, and DEF performed a comprehensive evaluation of these alternatives in March 2014 with internal subject matter experts. DEF determined that a combination of physical, chemical, and biological treatments would be more economical and involve less risk than deep-well injection. This strategy will be finalized following publication and review of the US EPA's Effluent Limitation Guidelines, expected in September 2015.

**AFFIDAVIT**

STATE OF FLORIDA

COUNTY OF PINELLAS

Before me, the undersigned authority, on this 22nd day of June, 2015, personally appeared **PATRICIA Q. WEST**, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, acknowledged before me that she provided the answers to Interrogatory Numbers 1 and 2 of Staff's First Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 1-4) in Docket No. 150007-EI and the responses are true and correct to the best of her knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 22nd day of June, 2015.

Patricia Q. West

Patricia Q. West

Notary Public

State of Florida

My commission Expires:

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 8, 2018
Commission # FF 070867

**AFFIDAVIT**

STATE OF FLORIDA

COUNTY OF Pinellas

Before me, the undersigned authority, on this 22nd day of June, 2015, personally appeared **JEFFREY SWARTZ**, who

( ✓ ) is personally known to me, or

( ) produced _____ as identification and who, acknowledged before me that he provided the answers to Interrogatory Numbers 3 and 4 of Staff's First Set of Interrogatories to Duke Energy Florida, Inc. (Nos. 1-4) in Docket No. 150007-EI and the responses are true and correct to the best of his knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 22nd day of June, 2015.

Jeffrey Swartz

Notary Public
State of Florida

My commission Expires:

SANDRA C. COPE
Notary Public - State of Florida
My Comm. Expires Mar 9, 2016
Commission # FF 070867

# 34

# DEF's Responses to Staff's Second Set of Interrogatories, Nos. 5-12
# &
# DEF's Supplemental Response to Staff's Second Set of Interrogatories, No. 10

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 34
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's Second Set of Interrogatories, Nos. 5-12.

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

In re: Environmental Cost Recovery Clause

DOCKET NO. 150007-EI

DATED: September 28, 2015

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 5-12)**

Duke Energy Florida, LLC ("DEF"), responds to Staff's Second Set of Interrogatories to DEF (Nos. 5-12), as follows:

INTERROGATORIES

**The following questions refer to the testimony of Witness Patricia Q. West filed on July 31, 2015.**

5. On page 5, the witness, testifies that capital expenditures for Project 16 are expected to be "lower than originally projected primarily due to a vendor reimbursement payment." Please explain the purpose and circumstances of the reimbursement.

**Answer:**

The 2015 capital expenditures are expected to be lower than originally projected due to the payment of two vendor invoices that contained duplicate costs. The duplicate payment was identified and reimbursement was received from the vendor in 2015.

6. On page 6, the witness testifies that the variance for Project 17 is "driven by the installation of continuous emission monitoring systems (CEMS) for mercury monitoring, compliance demonstration and feedback to re-emission control system." Please describe steps taken by DEF to ensure that the costs incurred for the installation of the CEMS were prudent and reasonable.

**Answer:**

Duke Energy used an enterprise-wide approach for MATS CEMS to reduce costs through economies of scale and to share experience between analogous projects. A formal bid process was conducted, and a single vendor/technology was selected for implementation across the applicable generating fleet. An enterprise-wide program manager coordinated the technology and economic assessments and supported individual projects during design and installation. Costs incurred by DEF were managed by an assigned project manager and project controls specialist. The project manager developed the scope and budget, supervised work activities, reviewed invoices and managed the overall budget. The project controls specialist processed invoices and tracked project cash flows. The mercury CEMS projects for Crystal River Units 4 & 5 are on track to meet the original schedule and budget.

7. On page 6, the witness testifies that, "DEF determined that continuous monitoring was necessary following elevated emissions in the second half of 2014 and a characterization study completed in December 2014." Please describe the events and considerations which led to DEF determining that the continuous monitoring was necessary.

**Answer:**

DEF performed an engineering study in the 4th quarter of 2014 to determine the apparent cause of elevated mercury emissions over the previous six months. The results showed that oxidized mercury captured by the wet scrubbers was being converted back to elemental mercury through a process known as re-emission. It was determined that a chemical injection system was necessary to mitigate re-emission and thus maintain compliant mercury emissions. DEF re-evaluated its emissions monitoring plan as a result of these changes in compliance assumptions. Potential technologies were compared with respect to equipment reliability, data availability, data resolution and expected costs. DEF determined that continuous monitoring was necessary to promptly identify and control re-emission conditions and to maintain sufficient data availability.

**The following questions refer to the testimony of Witness Garry Miller filed on July 31, 2015.**

8. On page 6, the witness testifies that, "DEF has contracts with two engineering firms to study CR ash landfill stability and ash placement." Please describe DEF's process for selecting the two engineering firms referenced by witness Miller.

**Answer:**

DEF contracted with URS-AECOM and Golder to study ash landfill stability and ash placement at its Crystal River (CR) site. These two engineering firms went through a qualifications-based solicitation process and were selected based on the firms' unique qualifications to perform the required scope of work and site-specific knowledge and familiarity with DEF's processes from previous engagements. These two firms were identified as having internationally-recognized levels of expertise with managing coal combustion residuals and performing stability analyses.

URS-AECOM will perform a geotechnical study of the ash landfill including surveys, field inspections, ash samples and engineering calculations to determine landfill stability of the CR ash landfill.

Golder will compile and review historical ash placement and testing documents, and develop process and procedures to address future ash placement requirements for CR.

9. On page 8 the witness testifies that, "additional capital costs in 2015 to comply with the vegetation management requirements are $100k." Please identify each activity or project that resulted in the referenced $100k.

**Answer:**

DEF estimated $100k to purchase two spider mowers to comply with CCR rule vegetation requirements. However, as explained in Garry Miller's direct testimony dated August 31, 2015, expected compliance activities associated with vegetation management changed. DEF has since determined that CCR vegetation management compliance can be achieved without spending the $100k of capital costs included in the July 31, 2015 ECRC Actual/Estimated Filing.

10. Please describe how DEF developed its estimated 2015 costs for work associated with the Temporary Gypsum Pad, FGD Blowdown Ponds, Emergency Action Plan, and Vegetation Management & Inspection Work.

**Answer:**

Per DEF's agreement with Staff, a response to this interrogatory will be provided on September 29, 2015.

**The following questions refer to the testimony of Witness Jeffrey Swartz filed on July 31, 2015.**

11. On page 2 the witness testifies that, "the $710k decrease [for Project 7.4] is due to lower than projected base routine project costs." What caused the lower than projected project costs?

**Answer:**

Certain costs that had previously not been allocated down to the project level and therefore were previously recovered through base rates were allocated down to the project level in the 2015 budget process and included in the 2015 projection filing. Upon identification of this, DEF made sure to remove these costs from ECRC actuals and this is the primary driver for the decrease from the projected costs.

12. On page 3 the witness testifies that, "a decision was made in November 2014 to replace and upgrade the Unit 1 ESP power supplies and internal components in order to achieve PM emission targets considered in the original compliance study."

a. How will the referenced replacements and upgrades result in achieving the PM emission targets considered in the original compliance study?

**Answer:**

The electrostatic precipitator (ESP) utilizes powered electrodes to charge the particulate matter (PM) in the flue gas and gather the particulate on collection plates. Mechanical rappers are then used to knock the particulate into hoppers below for removal. The installation of the components described in part (b) have resulted in improved particulate collection efficiency and equipment availability, reducing overall PM emissions to levels that will support compliance as anticipated in the original study.

b. Please identify and describe each replacement and upgrade.

**Answer**

To meet the more stringent PM emissions limitations in the MATS rule, power supplies were upgraded and re-sectionalized to increase electrical output and to improve the response to dynamic conditions. New collection plates were installed to increase collecting surface area and to support the high electrical output from the new power supplies. New rappers were installed to improve cleaning efficiency, required by the increased particulate collection and challenging electrical characteristics of the alternate fuel. Lastly, wire electrodes were

replaced with more reliable rigid discharge electrodes to improve equipment availability.

**AFFIDAVIT**

STATE OF FLORIDA

COUNTY OF PINELLAS

Before me, the undersigned authority, on this 28 day of September, 2015, personally appeared **JEFFREY SWARTZ**, who

( ✓ ) is personally known to me, or

( ) produced _____ as identification and who, acknowledged before me that he provided the answers to Interrogatory Numbers 5, 6, 7, and 12 of Staff's Second Set of Interrogatories to Duke Energy Florida, LLC (Nos. 5-12) in Docket No. 150007-EI and the responses are true and correct to the best of his knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 28 day of September, 2015.

Jeffrey Swartz

Notary Public

State of Florida

CHARLENE D BOULIANE
MY COMMISSION #FF148831
EXPIRES August 6, 2018
(407) 398-0153 FloridaNotaryService.com

My commission Expires:

August 6, 2018

**AFFIDAVIT**

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

Before me, the undersigned authority, on this 28th day of September, 2015, personally appeared **GARRY MILLER**, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, acknowledged before me that he provided or reviewed and adopted the answer to Interrogatory Numbers 8, 9, and 10 of Staff's Second Set of Interrogatories to Duke Energy Florida, LLC (Nos. 5-12) in Docket No. 150007-EI and the responses are true and correct to the best of his knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 28th day of September, 2015.

Garry Miller

Beth Jenkins Horsley
Notary Public
Gaston County
North Carolina
My Commission Expires 8/25/2016

Notary Public
State of North Carolina

My commission Expires: 08/25/2016

**AFFIDAVIT**

STATE OF FLORIDA

COUNTY OF PINELLAS

Before me, the undersigned authority, on this 25 day of September, 2015, personally appeared **THOMAS G. FOSTER**, who

( X ) is personally known to me, or

( ) produced _____ as identification and who, acknowledged before me that he provided the answer to Interrogatory Number 11 of Staff's Second Set of Interrogatories to Duke Energy Florida, LLC (Nos. 5-12) in Docket No. 150007-EI and the responses are true and correct to the best of his knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 25 day of September, 2015.

Thomas G. Foster

Sarah Hirschman Libes
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF105231
Expires 3/23/2018

Notary Public
State of Florida

My commission Expires:

3/23/2018

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

In re: Environmental Cost Recovery Clause

DOCKET NO. 150007-EI

DATED: September 29, 2015

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 5-12)**

Duke Energy Florida, LLC ("DEF"), provides its Supplemental Response to Staff's Second Set of Interrogatories to DEF (Nos. 5-12), specifically question 10 as follows:

INTERROGATORIES

**The following questions refer to the testimony of Witness Garry Miller filed on July 31, 2015.**

10. Please describe how DEF developed its estimated 2015 costs for work associated with the Temporary Gypsum Pad, FGD Blowdown Ponds, Emergency Action Plan, and Vegetation Management & Inspection Work.

**Answer:**

Estimated 2015 costs for work associated with the Temporary Gypsum Pad, Emergency Action Plan FGD Blowdown Ponds, and Vegetation Management and Inspection Work were developed as follows:

Temporary Gypsum Pad (TGP)
DEF estimated $1.5M for the installation of a windscreen around the gypsum pad at CR. However, as explained in Garry Miller's direct testimony dated August 31, 2015, expected compliance activities associated with the TGP subsequently changed. Based on additional analysis, DEF will be unable to complete this permanent dust control system

by October 19, 2015 (effective CCR compliance date). Instead, DEF will employ a temporary dust mitigation solution while a permanent solution is constructed. The temporary solution consists of monitoring wind conditions and using a water truck, at the appropriate times throughout each day (depending on the season), to mitigate potential dusting of material during wind events, in conjunction with the maintenance of the existing concrete slab and leachate collection system. The cost of the temporary solution is estimated to be $75,000 in 2015. The permanent solution is expected to be in-service by October 2016.

Emergency Action Plan (EAP)

DEF estimated $24,000 for development of an EAP for the CR FGD Blowdown Ponds. This amount was based on an estimate provided by AMEC Inc.

FGD Blowdown Ponds

DEF estimated $200,000 to conduct a dam hazard classification assessment as required by the CCR rule for both FGD blowdown ponds. This amount was based on an estimate with CCR vegetation management and inspection work at CR.

Vegetation Management and Inspection Work

DEF estimated $47,000 for internal labor costs to complete weekly inspections of the Ash Disposal Area and FGD Blowdown Ponds, and $17,000 of contract labor for required CCR vegetation management at the FGD Blowdown Ponds and Ash Landfill.

# 35

# DEF's Responses to Staff's Third Set of Interrogatories, No. 13

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 35
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's Third Set of Interrogatories, No. 13. [Bates
150007 Hearing Exhibit 00034

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environment Cost Recovery Clause

DOCKET NO. 150007-EI

DATED: October 5, 2015

**DUKE ENERGY FLORIDA LLC'S RESPONSE TO STAFF'S THIRD SET OF INTERROGATORIES (NO. 13)**

Duke Energy Florida, LLC ("DEF"), responds to Staff's Third Set of Interrogatories to DEF (No. 13), as follows:

**INTERROGATORIES**

13. On page 3 of DEF witness Jeffrey Swartz's August 31, 2015, testimony, the witness identifies $1.2 million of projected CR4 outage costs. Please describe the activities that are projected to result in the estimated $1.2 million of O&M costs.

**Answer:**

CR4 scheduled outage maintenance activities include absorber draining and cleaning; upper absorber header maintenance; absorber inlet duct cleaning and repair; absorber recycle pump inspection and repair; absorber tile inspection and repair; absorber bleed pump inspection and repair; FGD tank inspections; FGD duct inspection and repair; mist eliminator cleaning and repair; agitator inspection and repair; scheduled outage preventative maintenance; and clinker mitigation system inspection and repair.

**AFFIDAVIT**

STATE OF FLORIDA

COUNTY OF Citrus

Before me, the undersigned authority, on this 30th day of September, 2015, personally appeared **JEFFREY SWARTZ**, who

( ✓ ) is personally known to me, or

( ) produced _____ as identification and who, acknowledged before me that he provided the answer to Interrogatory Number 13 of Staff's Third Set of Interrogatories to Duke Energy Florida, LLC (No. 13) in Docket No. 150007-EI and the responses are true and correct to the best of his knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of September, 2015.

JR Swartz

Jeffrey Swartz

Barbara Martinuzzi

Notary Public

State of Florida

My commission Expires:

May 10, 2017

BARBARA MARTINUZZI
Notary Public - State of Florida
My Comm. Expires May 10, 2017
Commission # EE 867914

# 36

# Commission Staff Final Audit Report for Duke Energy Florida, Inc., dated June 2, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 36
PARTY: STAFF
DESCRIPTION: Commission Staff Final Audit Report for Duke Energy Florida Inc., dated

FILED JUN 02, 2015
DOCUMENT NO. 03296-15
FPSC - COMMISSION CLERK

State of Florida

# Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

## -M-E-M-O-R-A-N-D-U-M-

**DATE:** June 2, 2015

**TO:** Office of Commission Clerk

**FROM:** Lynn M. Deamer, Chief of Auditing, Office of Auditing and Performance Analysis

**RE:** Docket No.: 150007-EI
Company Name: Duke Energy Florida, Inc.
Company Code: EI801
Audit Purpose: Environmental Cost Recovery Clause
Audit Control No: 15-014-2-1

Attached is the final audit report for the Utility stated above. I am sending the Utility a copy of this memo and the audit report. If the Utility desires to file a response to the audit report, it should send a response to the Office of Commission Clerk. There is no confidential work papers associated with this audit.

LMD/cp

Attachment: Audit Report

cc: Office of Auditing and Performance Analysis File

**State of Florida**

# Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tampa District Office

## Auditor's Report

Duke Energy Florida, Inc.
Environmental Cost Recovery Clause

**Twelve Months Ended December 31, 2014**

Docket No. 150007-EI
Audit Control No. 15-014-2-1
**May 4, 2015**

Intesar Terkawi
Audit Manager

Linda Hill
Reviewer

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150007 Hearing Exhibits 00090

## Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Engineering in its audit service request dated January 14, 2015. We have applied these procedures to the attached summary exhibit and to several related schedules prepared by Duke Energy Florida, Inc. in support of its 2014 filing for the Environmental Cost Recovery Clause in Docket No. 150007-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

## Objectives and Procedures

## General

Definitions

Utility refers to Duke Energy Florida, Inc.
ECRC refers to the Environmental Cost Recovery Clause.

## Capital Investment

Utility Plant in Service

**Objectives:** The objectives were to verify all ECRC project-related plant additions, retirements and adjustments for the period January 1, 2014, through December 31, 2014.

**Procedure:** We traced Plant in Service and Accumulated Depreciation to the general ledger for each capital project listed on the 2014 Form 42-8A. No exceptions were noted.

Construction Work in Progress

**Objectives:** The objectives were to verify net investments associated with the following capital projects and to determine whether any project which involved the replacement or retirement of an existing plant asset is retired at the installed costs by the Utility in accordance with Florida Public Service Commission Rule 25-6.0142(4)(b), F.A.C.:

1) Project 16 - NPDES-Intermediate
2) Project 17.1 - MATS-Anclote Gas Conversion-Energy
3) Project 17.2 - MATS-Crystal River Units 1 & 2 Energy.

**Procedures:** We judgmentally selected a sample of capital investment invoices from each of the three projects listed above. We determined whether additions had appropriate supporting documentation and were recorded to the correct project and account. We determined whether items that were replaced had a corresponding retirement. We compared the ledger to the Depreciation Base and the Non-Interest Bearing amounts on Form 42-8A. No exceptions were noted.



150007 Hearing Exhibits 00092

## Revenue

Operating Revenue

**Objectives:** The objectives were to determine the actual Kilowatt Hours (KWH) sold for the period January 1, 2014, through December 31, 2014, and whether the Utility applied the Commission approved cost recovery factor to actual KWH sales for the ECRC.

**Procedures:** We reconciled the 2014 filing to the Utility's monthly ECRC monthly Revenue Reports. We applied the billing factors by rate class from Order No. PSC-13-0606-FOF-EI to KWH sales. We recalculated revenues for the months of January through December. We selected a sample of residential and commercial customers' bills for the months of April and September 2014 and recalculated each to verify the use of the correct tariff rate for each of the Environmental, Capacity, Fuel, Conservation and Nuclear Clauses. No exceptions were noted.

## Expense

Operation and Maintenance Expense

**Objectives:** The objectives were to determine whether Operation and Maintenance (O&M) Expenses listed on the Utility's Form 42-5A filing was supported by adequate documentation and that the expenses are appropriately recoverable through the ECRC.

**Procedures:** We traced expenses in the filing to the general ledger. We judgmentally selected a sample of O&M Expenses for testing for the months of March, April and November 2014. The source documentation for selected items was reviewed to ensure the expense was related to the ECRC and that the expense was charged to the correct accounts. No exceptions were noted.

Depreciation and Maintenance Expense

**Objective:** The objective was to determine whether the most recent Commission approved depreciation rates or amortization periods were used in calculating Depreciation Expense.

**Procedures:** We traced total year Depreciation Expense for each capital project listed on Form 42-8A to the general ledger detail. We recalculated 2014 Depreciation Expense on a test basis using the plant balances and depreciation rates per Order No. PSC-10-0131-FOF-EI. No exceptions were noted.

## Other

$SO_2$ Allowances

**Objectives:** The objectives were to verify investments, inventory, expensed amounts, and allowance auctions proceeds and to verify amounts included in Working Capital, Form 42-8A..



150007 Hearing Exhibits 00093

**Procedures:** We trace d 2014 consumption for $SO_2$ allowances from the Utility's detailed allowances reports to the total emission schedule on Form 42-8A. We recalculated amounts included in Working Capital, Form 42-8A page 5. We verified the wholesale portion of the NOx and SO2 Allowance Expense. We traced the sale proceeds to the to the Environmental Protection Agency's payment details.

## True-Up

**Objective:** The objective was to determine if the True-Up and Interest Provision as filed on Form 42-2A was properly calculated.

**Procedures:** We traced the December 31, 2013, True-Up Provision to the Commission Order. We recalculated the True-Up and Interest Provision amounts as of December 31, 2014, using the Commission approved beginning balance as of December 31, 2013, the Financial Commercial Paper rates and the 2014 ECRC revenues and costs. No exceptions were noted

## Analytical Review

**Objective:** The objective was to perform an analytical review of the Utility's ECRC revenues and expenses to determine if there were any material changes or inconsistencies from the prior years.

**Procedures:** We compared 2014 to the 2013 revenues and expenses. We requested explanations from the Utility for the variances. Explanations provided were sufficient. Further follow-up was not required.



150007 Hearing Exhibits 00094

## Audit Findings

**None**



150007 Hearing Exhibits 00095

# Exhibit

## Exhibit 1: True-Up

**DUKE ENERGY FLORIDA**
**Environmental Cost Recovery Clause**
**Final True-Up**
**January 2014 - December 2014**

**End-of-Period True-Up Amount**
**(in Dollars)**

Form 42-2

Docket No. 150007-
Duke Energy Flo
Witness: T. G. Pos
Exh. No. __ (TGP-
Page 1 of

| Line | Description | | Actual Jan-14 | Actual Feb-14 | Actual Mar-14 | Actual Apr-14 | Actual May-14 | Actual Jun-14 | Actual Jul-14 | Actual Aug-14 | Actual Sep-14 | Actual Oct-14 | Actual Nov-14 | Actual Dec-14 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (net of Revenue Taxes) | | $6,054,777 | $6,743,406 | $5,696,498 | $5,684,006 | $6,810,501 | $7,824,663 | $8,347,610 | $9,299,243 | $8,732,198 | $7,364,114 | $6,641,150 | $6,019,544 | $85,628,61 |
| 2 | True-Up Provision | (19,568,336) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (1,630,695) | (19,568,33 |
| | (Order No. PSC-13-0606-FOF-EI) | | | | | | | | | | | | | | |
| 3 | ECRC Revenues Applicable to Period (Lines 1 + 2) | | $4,424,082 | 5,112,711 | 4,065,803 | 4,053,312 | 5,180,306 | 6,193,968 | 6,716,915 | 7,668,548 | 7,101,503 | 5,733,419 | 5,010,454 | 4,388,850 | 66,059,27 |
| 4 | Jurisdictional ECRC Costs | | | | | | | | | | | | | | |
| | a. O & M Activities (Form 42-5A, Line 9) | | $2,420,856 | $2,839,207 | $3,929,619 | $4,154,336 | $2,978,741 | $2,917,017 | $3,098,717 | $3,448,643 | $3,675,270 | $3,665,506 | $4,696,078 | $3,647,528 | $41,495,49 |
| | b. Capital Investment Projects (Form 42-7A, Line 9) | | 2,053,047 | 2,064,099 | 2,036,803 | 2,018,418 | 2,007,255 | 2,154,564 | 2,140,476 | 2,155,799 | 2,143,902 | 2,169,391 | 2,194,094 | 2,391,498 | 25,508,56 |
| | c. Other (A) | | 0 | 0 | (14,291,145) | 0 | $86,290 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (13,704,85 |
| | d. Total Jurisdictional ECRC Costs | | $4,453,903 | $4,897,306 | ($8,324,729) | $6,172,754 | $5,372,286 | $5,081,581 | $5,239,193 | $5,604,442 | $5,819,172 | $5,834,897 | $6,890,172 | $6,038,026 | $53,299,20 |
| 5 | Over/(Under) Recovery (Line 3 - Line 4d) | | ($29,820) | $215,405 | $12,390,532 | ($1,919,442) | ($192,180) | $1,112,387 | $1,477,723 | $2,064,106 | $1,282,332 | ($101,477) | ($1,879,716) | ($1,649,176) | $12,760,47 |
| 6 | Interest Provision (Form 42-5A, Line 10) | | (748) | (794) | (312) | 106 | 134 | 211 | 356 | 633 | 831 | 804 | 1,005 | 1,926 | 3,55 |
| 7 | Beginning Balance True-Up & Interest Provision | | (19,568,336) | (17,568,210) | (16,122,804) | (3,901,989) | (2,150,630) | (951,982) | 1,791,511 | 4,900,086 | 8,585,520 | 11,499,377 | 13,029,199 | 12,781,180 | (19,568,33 |
| | a. Deferred True-Up - January 2013 - December 2013 (Order No. PSC-14-0543-FOF-EI) | | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,998 | 3,807,99 |
| 8 | True-Up Collected/(Refunded) (see Line 2) | | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 1,630,695 | 19,568,33 |
| 9 | End of Period Total True-Up (Lines 5+6+7+7a+8) | | ($14,160,212) | ($12,914,906) | $1,908,009 | $1,617,368 | $2,856,016 | $5,599,309 | $8,708,084 | $12,393,518 | $15,307,375 | $16,837,197 | $16,589,178 | $16,572,922 | $36,572,02 |
| 10 | Adjustments to Period Total True-Up Including Interest | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 11 | End of Period Total True-Up Over/(Under) (Lines 9 + 10) | | ($14,160,212) | ($12,914,906) | $1,908,009 | $1,617,368 | $2,856,016 | $5,599,309 | $8,708,084 | $12,393,518 | $15,307,375 | $16,837,197 | $16,589,178 | $16,572,922 | $36,572,02 |

Notes:
(A) Retail portion of the property tax settlement between Citrus County and DEF for assessment years 2012 and 2013.



150007 Hearing Exhibits 00096

# 37

# Duke Energy Florida Letter advising of new environmental projects, dated July 1, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 37
PARTY: STAFF
DESCRIPTION: Duke Energy Florida Letter advising of new environmental projects, dated
150007 Hearing Exhibits 00037

FILED JUL 01, 2015
DOCUMENT NO. 04051-15
FPSC - COMMISSION CLERK

DUKE ENERGY. FLORIDA

Matthew R. Bernier
Senior Counsel

July 1, 2015

**VIA ELECTRONIC FILING**

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

Re: *Environmental Cost Recovery Clause; Docket No. 150007-EI*

Dear Ms. Stauffer:

On behalf of Duke Energy Florida, Inc. ("DEF"), I am writing to advise the Commission that, at this time, DEF has identified the following new environmental projects for which it intends to seek approval for cost recovery in the above referenced docket:

- **Clean Water Rule clarifying the scope of the Waters of the United States ("WOTUS")** – On May 27, 2015, the EPA issued a final rule that, among other things, clarifies the meaning and scope of the WOTUS for purposes of the Clean Water Act. The rule was published in the Federal Register on June 29, 2015, and will take effect August 28, 2015. DEF is in the process of analyzing the new rule requirements and potential impacts and compliance options at operational sites, and expects to incur compliance costs in 2015 and 2016. However, the full extent of compliance activities and associated expenditures cannot be determined at this time as DEF has not had sufficient opportunity to analyze the rule's impacts on effected facilities and compliance alternatives.

- **Underground Storage Tank ("UST")** - The final draft of the UST rule is currently in process preceding adoption approval by the Secretary of the Florida Department of Environmental Protection ("FDEP"). DEF is in the process of analyzing the draft rule requirements and potential impacts at operational sites and compliance options for the affected unit, and expects to incur compliance costs in 2015 and 2016. However, the full extent of compliance activities and associated expenditures cannot be determined at this time as the final rule has not been issued and is subject to change.

106 East College Avenue, Suite 800 • Tallahassee, Florida 32301
Phone: 850.521.1428 • Fax: 727.820.5041 • Email: matthew.bernier@duke-energy.com

- **Above Ground Storage Tanks ("AST")** –The FDEP is expected to issue amendments to its AST rule in 2016. DEF continues to engage with the FDEP in the rulemaking process, but it is unclear what potential impacts the proposed rule amendments will have on its operational sites, and to what extent potential compliance options will be available and ultimately pursued. However, DEF expects to incur compliance costs in 2016, although the full extent of compliance activities and associated expenditures cannot be determined at this time.

- **Coal Combustion Residuals ("CCR") Rule** – On April 17, 2015, the EPA published the CCR rule, *see* 80 FR 21301, codified at 40 CFR Parts 257 and 261, which becomes effective October 17, 2015. The rule requires an analysis of existing CCR landfills and surface impoundments and implementation of various requirements ranging from 6 to 42 months. The CCR rule includes multiple new requirements for CCR Units such as CCR landfills and CCR surface impoundments including: Location restrictions (40 CFR 257.64); Run off and run on controls (40 CFR 257.81); Fugitive emissions control plan (40 CFR 257.80); Inspections (40 CFR 257.83); Groundwater monitoring and corrective action (40 CFR 257.90 - .98); Closure and post closure care (40 CFR 257.103 -.104); and Recordkeeping, notification (40 CFR 257.105-107). DEF is in the process of analyzing potential impacts of compliance options. DEF will incur compliance costs in 2015, 2016 and beyond. However, the full extent of compliance activities and associated expenditures cannot be determined until further analysis and assessments of the CCR rule are complete.

DEF also notes that its 2016 projection filing will include costs for the modified Crystal River North Flue Gas Desulfurization("FGD") blowdown wastewater project to comply with FDEP permit requirements. The specific discharge method to be used is contingent on the final EPA Effluent Limitation Guidelines ("ELG") rule expected September 30, 2015. DEF does not have a final estimate of total project costs at this time as the full extent of compliance activities and associated expenditures is subject to change based on future regulatory requirements.

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this filing.

Respectfully,

*/s/ Matthew R. Bernier*
Matthew R. Bernier

MRB/db

## CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 1st day of July, 2015.

*/s/ Matthew R. Bernier*
Attorney

| | |
|---|---|
| Charles Murphy, Esq.<br>Office of General Counsel<br>Florida Public Service Commission<br>2540 Shumard Oak Blvd.<br>Tallahassee, FL 32399-0850<br>cmurphy@psc.state.fl.us<br><br>James D. Beasley/J. Jeffry Wahlen/Ashley M. Daniels<br>Ausley Law Firm<br>P.O. Box 391<br>Tallahassee, FL 32302<br>jbeasley@ausley.com<br>jwahlen@ausley.com<br>adaniels@ausley.com<br><br>Jeffrey A. Stone/Russell A. Badders/Steven R. Griffin<br>Beggs & Lane<br>P.O. Box 12950<br>Pensacola, FL 32591<br>jas@beggslane.com<br>rab@beggslane.com<br>srg@beggslane.com<br><br>Jon C. Moyle, Jr., Esq.<br>Moyle Law Firm, P.A.<br>118 North Gadsden Street<br>Tallahassee, FL 32301<br>jmoyle@moylelaw.com<br><br>Kenneth Hoffman<br>Florida Power & Light Company<br>215 S. Monroe Street, Suite 810<br>Tallahassee, FL 32301-1858<br>Ken.Hoffman@fpl.com<br><br>Gary V. Perko, Esq.<br>Hopping Green & Sams<br>P.O. Box 6526<br>Tallahassee, FL 32314<br>gperko@hgslaw.com | John T. Butler, Esq.<br>Florida Power & Light Company<br>700 Universe Blvd. (LAW/JB)<br>Juno Beach, FL 33408-0420<br>john.butler@fpl.com<br><br>Robert L. McGee, Jr.<br>Gulf Power Company<br>One Energy Place<br>Pensacola, FL 32520-0780<br>rlmcgee@southernco.com<br><br>Charles J. Rehwinkel<br>J.R. Kelly<br>Office of Public Counsel<br>c/o The Florida Legislature<br>111 West Madison Street, Room 812<br>Tallahassee, FL 32399-1400<br>rehwinkel.charles@leg.state.fl.us<br>kelly.jr@leg.state.fl.us<br><br>James W. Brew/Owen J. Kopon /Laura A. Wynn<br>Stone Matheis Xenopoulos & Brew, PC<br>1025 Thomas Jefferson Street NW<br>8th Floor, West Tower<br>Washington, DC 20007<br>jbrew@smxblaw.com<br>ojk@smxblaw.com<br>laura.wynn@smxblaw.com<br><br>Ms. Paula K. Brown<br>Tampa Electric Company<br>P.O. Box 111<br>Tampa, FL 33601<br>regdept@tecoenergy.com |

# 38

# TECO's Responses to Staff's First Set of Interrogatories, Nos. 1-2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 38
PARTY: STAFF
DESCRIPTION: TECO's Responses to Staff's First Set of Interrogatories, Nos. 1-2.[Bates
150007 Hearing Exhibit 0010

# BEFORE THE

# FLORIDA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| **In re: Environmental Cost Recovery Clause** | ) | **DOCKET NO. 150007-EI** |
| | ) | **FILED: September 28, 2015** |

## TAMPA ELECTRIC COMPANY'S

## ANSWERS TO FIRST SET OF INTERROGATORIES (NOS. 1-2)

## OF

## FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 1-2) propounded and served on August 28, 2015, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150007-EI
INDEX TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-2)

| Number | Witness | Subject | Bates Stamped Page |
|---|---|---|---|
| 1 | Rusk | On page 6, the witness testifies that the variance in costs, for Big Bend PM Minimization and Monitoring, "is due to an increase in price for routine monthly Best Operating Practices ('BOP') inspections."<br>a) Are the referenced inspections performed by TECO or a contractor?<br>b) What caused the increase in price described by the witness? | 1 |
| 2 | Rusk | On pages 8 and 9, the witness testifies that the variance for the MATS program "is due to [TECO] utilizing internal labor resources for stack testing." What led to the decision for TECO to use internal labor as opposed to contract labor? | 2 |

Penelope Rusk

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

**1.** On page 6, the witness testifies that the variance in costs, for Big Bend PM Minimization and Monitoring, "is due to an increase in price for routine monthly Best Operating Practices ('BOP') inspections."

a. Are the referenced inspections performed by TECO or a contractor?

b. What caused the increase in price described by the witness?

**A.** a. The BOP inspections are performed by a contractor.

b. Upon further investigation, the company discovered that the variance for the Big Bend PM Minimization and Monitoring project was actually caused by two factors. The first cause was that costs for the annual inspections of the penthouse and hoppers were inadvertently omitted from the original 2015 projection and correctly included in the 2015 actual-estimated filing. Secondly, the portion of the variance caused by the increase in price for inspections was caused by an increase in the hourly rate for labor that is provided under the master agreement between Tampa Electric and the contractor that performs these services. The previous change in this contractual rate occurred three years ago.



150007 Hearing Exhibits 00104

**2.** On pages 8 and 9, the witness testifies that the variance for the MATS program "is due to [TECO] utilizing internal labor resources for stack testing." What led to the decision for TECO to use internal labor as opposed to contract labor?

**A.** When Tampa Electric prepared the projection for the stack testing, internal resources were not expected to be available to meet MATS rule compliance, so the company planned to utilize contract labor for the MATS testing. However, Tampa Electric utilizes the internal team when it is available. The use of internal labor resources to complete the stack testing reduced the planned MATS program costs, since internal labor costs are not charged to the clause.

# 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. 1-2) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 23rd day of September, 2015.

Penelope Rusk

Sworn to and subscribed before me this 23rd day of September, 2015.

Cynthia R. Kyle

Notary Public State of Florida
Cynthia R Kyle
My Commission FF 197516
Expires 03/01/2019

My Commission expires _____

# 39

# TECO's Responses to Staff's Second Set of Interrogatories, No. 3

# BEFORE THE

# FLORIDA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| **In re: Environmental Cost Recovery Clause** | ) ) | **DOCKET NO. 150007-EI FILED: OCTOBER 5, 2015** |

## TAMPA ELECTRIC COMPANY'S

## ANSWERS TO SECOND SET OF INTERROGATORIES (NO. 3)

## OF

## FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (No. 3) propounded and served on September 14, 2015, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150007-EI
INDEX TO STAFF'S SECOND SET OF INTERROGATORIES (NO. 3)

| Number | Witness | Subject | Bates Stamped Page |
|---|---|---|---|
| 3 | Carpinone | On page 6 of witness Carpinone's testimony, the witness testifies that "the capital expenditures for the Big Bend Unit 3 SCR are projected to be $2,000,000 for a catalyst replacement." Please explain what prompted the describe replacement. | 1 |

Paul Carpinone
Director, Environmental

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

**3.** On page 6 of witness Carpinone's testimony, the witness testifies that "the capital expenditures for the Big Bend Unit 3 SCR are projected to be $2,000,000 for a catalyst replacement." Please explain what prompted the describe replacement.

**A.** The catalyst performance is monitored by collecting and analyzing samples. The catalyst samples are typically collected from each layer annually during a planned unit outage. The samples are sent to a third party laboratory for analysis of the catalyst properties. If the test results show the catalyst meets the specifications, the catalyst layer will remain in service and is retested during the next planned outage. However, if test results show the catalyst does not meet the supplier's recommendations, then the catalyst is scheduled for replacement during the next planned outage.

The company expects that it will need to replace Big Bend Unit 3's catalyst in 2016; however, in the event that the test results indicate it does not need to be replaced in 2016, the capital expenditure will not occur in 2016 but deferred to 2017.



150007 Hearing Exhibits 00110

# AFFIDAVIT

**STATE OF FLORIDA** )
)
**COUNTY OF HILLSBOROUGH** )

Before me the undersigned authority personally appeared Ashley Sizemore who deposed and said that she is Regulatory Rate Analyst, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (No. 3) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 2nd day of October, 2015.

Ashley Sizemore

Sworn to and subscribed before me this 2nd day of October, 2015.

T. C. V.

Notary Public State of Florida
Tison C Vega
My Commission EE 165415
Expires 02/01/2016

My Commission expires _____

# 39

# TECO's Responses to Staff's Second Set of Interrogatories, No. 3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 39
PARTY: STAFF
DESCRIPTION: TECO's Responses to Staff's Second Set of Interrogatories, No. 3.[Bates
150007 Hearing Exhibits 00107

# BEFORE THE

# FLORIDA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| **In re: Environmental Cost Recovery Clause** | ) ) | **DOCKET NO. 150007-EI FILED: OCTOBER 5, 2015** |

## TAMPA ELECTRIC COMPANY'S

## ANSWERS TO SECOND SET OF INTERROGATORIES (NO. 3)

## OF

## FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (No. 3) propounded and served on September 14, 2015, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150007-EI
INDEX TO STAFF'S SECOND SET OF INTERROGATORIES (NO. 3)

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Paul Carpinone
Director, Environmental

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

**3.** On page 6 of witness Carpinone's testimony, the witness testifies that "the capital expenditures for the Big Bend Unit 3 SCR are projected to be $2,000,000 for a catalyst replacement." Please explain what prompted the describe replacement.

**A.** The catalyst performance is monitored by collecting and analyzing samples. The catalyst samples are typically collected from each layer annually during a planned unit outage. The samples are sent to a third party laboratory for analysis of the catalyst properties. If the test results show the catalyst meets the specifications, the catalyst layer will remain in service and is retested during the next planned outage. However, if test results show the catalyst does not meet the supplier's recommendations, then the catalyst is scheduled for replacement during the next planned outage.

The company expects that it will need to replace Big Bend Unit 3's catalyst in 2016; however, in the event that the test results indicate it does not need to be replaced in 2016, the capital expenditure will not occur in 2016 but deferred to 2017.



150007 Hearing Exhibits 00110

# AFFIDAVIT

**STATE OF FLORIDA** )
)
**COUNTY OF HILLSBOROUGH** )

Before me the undersigned authority personally appeared Ashley Sizemore who deposed and said that she is Regulatory Rate Analyst, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (No. 3) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 2nd day of October, 2015.

Ashley Sizemore

Sworn to and subscribed before me this 2nd day of October, 2015.

T. C. V.

Notary Public State of Florida
Tison C Vega
My Commission EE 165415
Expires 02/01/2016

My Commission expires _____

# 40

# Commission Staff Final Audit Report for Tampa Electric Company, Dated June 4, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 40
PARTY: STAFF
DESCRIPTION: Commission Staff Final Audit Report for Tampa Electric Company, dated
150007 Hearing Exhibits 00113

FILED JUN 04, 2015
DOCUMENT NO. 03347-15
FPSC - COMMISSION CLERK

**State of Florida**

# Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

## -M-E-M-O-R-A-N-D-U-M-

**DATE:** June 4, 2015

**TO:** Office of Commission Clerk

**FROM:** Lynn M. Deamer, Chief of Auditing, Office of Auditing and Performance Analysis

**RE:** Docket No.: 150007-EI
Company Name: Tampa Electric Company
Company Code: EI806
Audit Purpose: Environmental Cost Recovery Clause
Audit Control No: 15-014-2-2

Attached is the final audit report for the Utility stated above. I am sending the Utility a copy of this memo and the audit report. If the Utility desires to file a response to the audit report, it should send a response to the Office of Commission Clerk. There is no confidential work papers associated with this audit.

LMD/cp

Attachment: Audit Report

cc: Office of Auditing and Performance Analysis File

State of Florida

# Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tampa District Office

## Auditor's Report

Tampa Electric Company
Environmental Cost Recovery Clause

**Twelve Months Ended December 31, 2014**

Docket No. 150007-EI
Audit Control No. 15-014-2-2
**May 15, 2015**

Linda Hill
Audit Manager

TK FOR INTESAR TERKAWI

Intesar Terkawi
Reviewer

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150007 Hearing Exhibits 00115

## Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Engineering in its audit service request dated January 14, 2015. We have applied these procedures to the attached summary exhibit and to several related schedules prepared by the Tampa Electric Company in support of its 2014 filing for the Environmental Cost Recovery Clause in Docket No. 150007-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

## Objectives and Procedures

## General

Definitions

Utility refers to the Tampa Electric Company.
ECRC refers to the Environmental Cost Recovery Clause.

## Capital Investments

Utility Plant in Service

**Objectives:** The objectives were to verify all ECRC project-related plant additions, retirements and adjustments for the period January 1, 2014, through December 31, 2014.

**Procedures:** We traced Plant in Service and Accumulated Depreciation to the general ledger for each capital project listed on the 2014 Form 42-8A. No exceptions were noted.

Construction Work in Progress

**Objective:** The objective was to verify net investments associated with the following capital projects and to determine whether any project which involved the replacement or retirement of an existing plant asset is retire at the installed costs by the Utility in accordance with Florida Public Service Commission Rule 25-6.0142(4)(b), F.A.C.:

1) Big Bend Units 1 7 2 FGD
2) Big Bend Unit 1 SCR
3) Big Bend Unit 4 SCR
4) Mercury Air Toxics Standards (MAT)

**Procedures:** We selected additions to capital projects for the months of February, April, and May 2014. We determined whether additions had appropriate supporting documentation and were recorded to the correct project and account. We determined whether items that were replaced had a corresponding retirement. We compared the ledger to the depreciation base and the non-interest bearing amounts on Form 42-8A. No exceptions were noted.

## Revenue

Operating Revenues

**Objectives:** The objectives were to determine the actual Kilowatt Hours (KWH) sold for the period January 1, 2014, through December 31, 2014, and whether the Utility applied the Commission approved cost recovery factor to actual KWH sales for the ECRC.

**Procedures:** We reconciled the 2014 filing to the Utility's monthly Environmental Revenue Reports. We computed the factors by rate code and compared them to the last Commission Order No. PSC-14-0643-FOF-EI. We selected a random sample of residential and commercial customers' bills for the month of April 2014. We recalculated each to verify the use of the correct tariff rate for the Capacity, Fuel, Conservation and Environmental Clauses. No exceptions were noted.

## Expense

Operation and Maintenance Expense

**Objectives:** The objectives were to determine whether Operation and Maintenance (O&M) Expenses listed on the Utility's Form 42-5A filing were supported by adequate documentation and that the expenses are appropriately recoverable through the ECRC.

**Procedures:** We traced expenses in the filing to the general ledger. We judgmentally selected a sample of payroll and non-payroll O&M Expenses for testing for the months of February, June, and August 2014. The source documentation for selected items was reviewed to ensure the expenses were related to the ECRC and that the expenses were charged to the correct accounts. No exceptions were noted.

Depreciation and Amortization

**Objective:** The objective was to determine whether the most recent Commission approved depreciation rates or amortization periods were used in calculating Depreciation Expense.

**Procedures:** We recalculated 2014 Depreciation Expense on a test basis using the plant balances and depreciation rates per Order No. PSC-10-0131-FOF-EI. We traced total year Depreciation Expense for each capital project listed on Form 42-8A to the general ledger detail. No exceptions were noted.

## Other

$SO_2$ Allowances

**Objectives:** The objectives were to verify investments, inventory, expensed amounts, allowance auction proceeds and to verify amounts included in Working Capital, Form 42-8A.



150007 Hearing Exhibits 00118

**Procedures:** We traced 2014 consumption for $SO_2$ Allowances from the Utility's detailed Allowances Reports to the Total Emissions Schedule on Form 42-5E. We determined whether NOx. Sales were made. We verified the 2014 vintage allowance for the sale of Hooker's Point. We verified all auction proceeds. We traced the jurisdictional factors to Order No. PSC-14-0643-FOF-EI. No exceptions were noted.

## True-up

**Objective:** The objective was to determine if the True-Up and Interest Provision as filed on Form 42-2A was properly calculated.

**Procedures:** We traced the December 31, 2013, True-Up Provision to the Commission Order. We recalculated the True-Up and Interest Provision amounts as of December 31, 2014, using the Commission approved beginning balance as of December 31, 2013, the Financial Commercial Paper rates, and the 2014 ECRC revenues and costs. No exceptions were noted.

## Analytical Review

**Objective:** The objective was to perform an analytical review of the Utility's ECRC Revenues and Expenses to determine if there were any material changes or inconsistencies from the prior year.

**Procedures:** We compared 2014 to 2013 and 2012 revenues and expenses. We requested explanations from the Utility for significant variances. Explanations provided were sufficient. Further follow-up was not required.



150007 Hearing Exhibits 00119

## Audit Findings

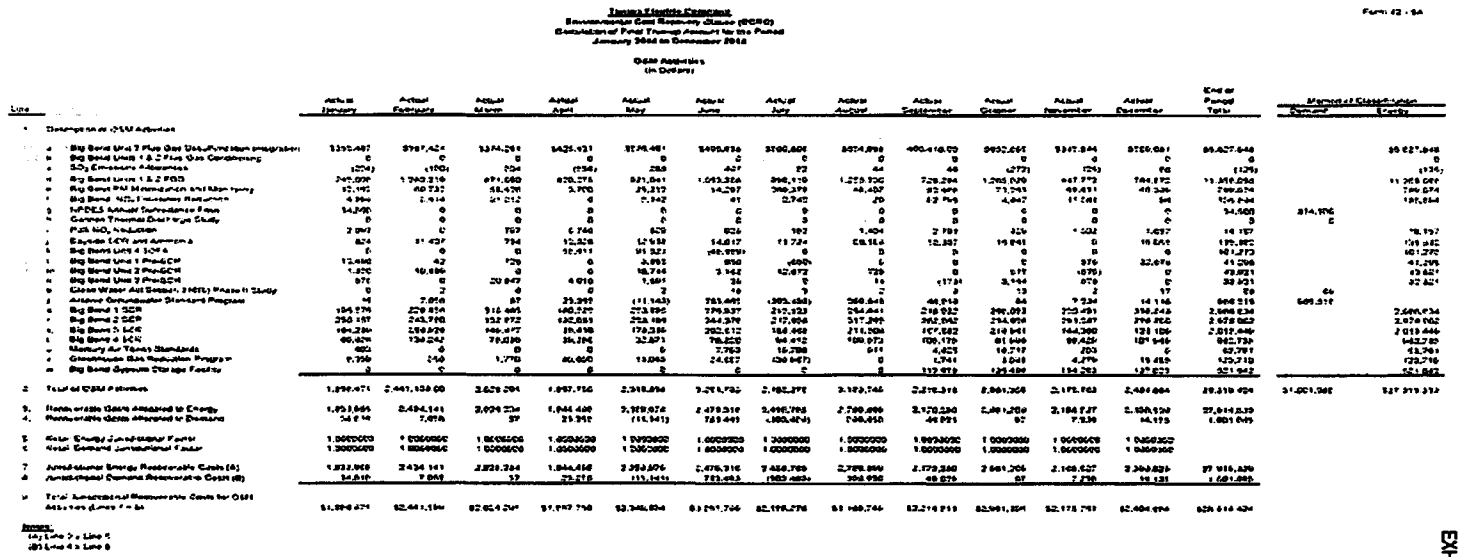
**None**



150007 Hearing Exhibits 00120

# Exhibit

## Exhibit 1: True-Up



DOCKET NO. 150007-EI
ECRC 2014 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 5, PAGE 1 OF 1





150007 Hearing Exhibits 00121

# 41

# GULF's Responses to Staff's First Set of Interrogatories, No. 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 41
PARTY: STAFF
DESCRIPTION: Gulf's Responses to Staff's First Set of Interrogatories, No. 1.[Bates Nos.
150007 Hearing Exhibits 00132

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In re: Environmental Cost Recovery Clause | ) | Docket No. 150007-EI |

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FIRST SET OF INTERROGATORIES (NO. 1)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's First Set of Interrogatories (No. 1) on the following pages.

Respectfully submitted by electronic mail the 29th day of June, 2015.

**JEFFREY A. STONE**
Florida Bar No. 325953
**RUSSELL A. BADDERS**
Florida Bar No. 007455
**STEVEN R. GRIFFIN**
Florida Bar No. 0627569
**BEGGS & LANE**
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
**Attorneys for Gulf Power Company**

1. On page 6, of witness Vick's testimony, the witness testifies that the Plant Crist above ground storage maintenance expenses were less than originally projected. What caused the above ground storage maintenance expenses to be less than originally projected?

ANSWER:

Plant Crist planned to expand and improve the concrete containment area under the coal unloading crane during 2014. The containment system is used to capture hydraulic oil that may be released in the event of a hydraulic system failure on the crane. Due to contractor availability and time constraints the containment work was delayed to 2015.

AFFIDAVIT

STATE OF FLORIDA )
)
COUNTY OF ESCAMBIA )

Docket No. 150007-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D. Ritenour

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

NOTARY PUBLIC STATE OF FLORIDA
MELISSA A. DARNES
MY COMMISSION # EE 150873
EXPIRES: December 17, 2015
Bonded Thru Budget Notary Services

Sworn to and subscribed before me this 26th day of June, 2015.

Melissa A. Darnes

Notary Public, State of Florida at Large

# 42

# GULF's Responses to Staff's Second Set of Interrogatories, Nos. 2-7

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 42
PARTY: STAFF
DESCRIPTION: Gulf's Responses to Staff's Second Set of Interrogatories, Nos. 2-7.[Bates

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In re: Environmental Cost Recovery Clause | ) | Docket No. 150007-EI |

GULF POWER COMPANY'S RESPONSES TO
STAFF'S SECOND SET OF INTERROGATORIES (NOS. 2-7)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Second Set of Interrogatories (Nos. 2-7) on the following pages.

Respectfully submitted by electronic mail the 28th day of September, 2015.

**JEFFREY A. STONE**
Florida Bar No. 325953
**RUSSELL A. BADDERS**
Florida Bar No. 007455
**STEVEN R. GRIFFIN**
Florida Bar No. 0627569
**BEGGS & LANE**
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
**Attorneys for Gulf Power Company**

**The following questions refer to Gulf's July 1, 2015, electronic filing (identifying new environmental projects) in Docket No. 150007-EI.**

2. For each estimated capital expenditure and estimated O&M expense, please describe how Gulf developed its estimates. Please include a list and description of sources relied on for each estimate.

ANSWER:

Gulf Power has followed an on-going process to develop, review, and update environmental compliance strategies and cost projections. The goal of this process is to identify reasonable, cost-effective compliance strategies that will minimize the impact on Gulf Power's customers while achieving environmental objectives and assuring compliance with all environmental requirements.

ELG O&M 2016

In June 2013, the EPA published a proposed Effluent Limitations Guidelines (ELG) rule which requested comments on a range of potential regulatory options for addressing certain waste streams from steam electric power plants and best management practices for Coal Combustion Residual (CCR) surface impoundments. The proposed rule is located in Title 40 Code of Federal Regulations (CFR) Part 423. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The estimated Effluent Limitations Guidelines (ELG) costs were provided by Gulf Power's consultants and were developed based on water use at the various plants. Gulf is examining ways to optimize water use and recycle it at each facility, with the goal of reducing costs for either the treatment of water or its ultimate disposal, in order to meet the new Effluent Limitations Guidelines Rule.

The dry ash studies cost estimates are associated with the engineering needed to identify available technologies with the potential to meet the ELG rule and to determine how best to convert wet ash systems to dry systems, thus developing the most efficient and lowest cost solution for meeting both the new CCR rule and the anticipated ELG rule. The costs also include preliminary engineering studies to evaluate ways to minimize discharges from wastewater units that are subject to the ELG rule.

Water Balance/Optimization/Dry Ash Studies $175,000

CCR Capital 2015

These costs are for developing a groundwater monitoring plan and the associated well installations as required by the new CCR rule. The costs are based on the number of monitoring wells that will be needed to monitor CCR facilities located at Plant Crist, Plant Smith and Plant Daniel. Gulf is utilizing trained hydrologists to determine the number, proper location, and depth of monitoring wells to meet the new CCR Rule.

Plant Crist ground water well installation $270,000
Plant Smith ground water well installation $210,000
Plant Daniel ground water well installation $180,000

CCR O&M 2015

The data management system costs listed below are for storage and evaluation of groundwater quality data necessary for the reporting required by the new CCR rule. In addition, website reporting will be used to report operational information, inspection results and studies required by the new rule. During 2015, Gulf is also required to install permanent markers at all CCR ponds and have annual inspections of the CCR impoundments and landfills performed by a professional engineer (PE). The cost projections are based on estimates Gulf received from its consultant to develop the data management system, website and to install the markers, as well as cost estimates for the requisite studies that were provided by the engineer that will be responsible for the annual inspections.

On August 24, 2015, the Florida Department of Environmental Protection issued a renewal NPDES permit for Plant Scholz. This permit has new conditions requiring the closure of the Plant Scholz CCR unit. Gulf projected expenses to be $600,000 in 2015 and $12.2 million in 2016 for the closure activities. The cost of the closure of Plant Scholz CCR unit was not included in the O&M dollars in Gulf's Preliminary List of New Projects due to it being a very new requirement in the draft renewal NPDES Permit for Plant Scholz, received from the Florida Department of Environmental Protection on August 24, 2015. The total cost of closure is estimated to be $30 million and the estimated completion date is 2018. These estimates were provided to Gulf by its consultant.

Data management system necessary for the CCR Rule $50,000
Annual Engineering Inspections $10,000
Install permanent markers at all CCR ponds $2,000
Scholz ash pond closure $600,000

CCR Capital 2016

The new CCR rule will require Gulf to design, operate, and maintain stormwater run-on and run-off systems for Gulf Power's CCR landfill facilities. To meet this new requirement, Gulf will install additional wastewater injection well capacity at Plant Crist and may be required to construct additional stormwater conveyance and pond systems. The Crist dry bottom ash system costs encompass the additional equipment needed to dewater bottom ash and then store the dry material in an onsite landfill. Gulf is investigating currently available technologies to identify the lowest cost solution for this project. The initial costs for the additional injection well system are based on costs incurred to install similar injection wells at that site. The cross media costs listed for Plant Smith include wastewater treatment required for the new CCR rule. This treatment is necessary before wastewater can be properly disposed in Gulf's permitted injection well system. The estimate is based on information from Gulf's consultant.

Plant Crist injection well expansion $3.0 million
Plant Crist dry bottom ash $2.5 million
Plant Smith cross media $3.8 million

CCR O&M 2016

In 2016, Gulf will conduct hydrologic and hydraulic capacity studies of the CCR ponds, compile a history of the structural integrity reports and design information for the CCR Units, prepare stormwater management plans, and conduct annual dust control and engineering inspections as well as groundwater monitoring. The O&M costs were estimated using existing costs for similar groundwater sampling and analytical analysis and the cost of recent stormwater design projects. As mentioned above in CCR O&M 2015, on August 24, 2015, the Florida Department of Environmental Protection issued a draft renewal of the NPDES permit for Plant Scholz. This permit has new conditions requiring the closure of the Plant Scholz CCR unit and Gulf projected expenses to be $12.2 million in 2016 for the closure activities. These estimates were provided to Gulf by its consultant.

Ground water well monitoring $150,000
Hydrologic and Hydraulic Capacity Evaluations $50,000
Stormwater Design and Planning $40,000
Annual Dust Control and Engineering Inspections $10,000
Scholz ash pond closure $12,200,000

3. Please list Gulf's generating facilities that will be affected by the Effluent Limitations Guidelines.

ANSWER:

Plants Crist, Daniel, Smith and, potentially, Pea Ridge.

**The following questions refer to the testimony of Witness James O. Vick, filed on July 31, 2015.**

4. On page 4, the witness testifies that the variance for Line Item 1.19 "is primarily due to a delay in replacing the FGAS fans in Plant Crist's Unit 7 SCR." Please identify the date that the replacement occurred and describe how the delay resulted in an increase in 2015 capital costs.

ANSWER:

To date, the Crist Unit 7 SCR Flue Gas Sample (FGAS) fans have not been replaced as originally projected in Gulf's 2015 Projection filing which results in a decrease in 2015 capital costs. During the fall outage of 2014, the fans were inspected and found to have more life than expected; therefore, no retirement and replacement expenditures were made. Offsetting the decrease in capital cost was the replacement of the flame scanner on Plant Crist's Unit 6, which was not included in Gulf's 2015 Projection filing. The flame scanners are a necessary component of the Low NOx Burners and have reached the end of their useful life. Estimated 2015 expenditures for the flame scanner are $204,589. Gulf witness James O. Vick inadvertently omitted discussion of the flame scanner replacement in his prefiled direct testimony filed on July 31st, 2015. Mr. Vick's prefiled direct testimony will be amended to include discussion of the flame scanner replacement. The combination of these two changes account for the increase in 2015 capital costs.

5. On page 4, the witness testifies that variance for Line Item 1.26 "is primarily due to two budget items." For the two budget items, please state the capital variance associated with each item.

ANSWER:

The first variance is due to the timing of when the Plant Daniel scrubber units are expected to be placed in service. The scrubbers are projected to be placed in service in October and November 2015 versus the prior projection of December 2015. This change in dates results in approximately $5.6 million of the variance. The second variance is a result of $1.8 million of modifications to the Plant Crist gypsum cell #2 that were not included in 2015 Projection filing. These modifications were needed in order to extract more gypsum from the pond. Modifications to cell #2 will also delay the construction of cell #1. The capital variance associated with these modifications is approximately $51,000.

6. On page 4 the witness testifies that, "Plant Daniel anticipates bringing the Unit 1 scrubber and common scrubber equipment in-service in the month of October and the Unit 2 scrubber in-service in November," instead of December. Please explain how/why the change in in-service date impacted the capital costs associated with Line Item 1.26.

ANSWER:

The variance associated with Line Item 1.26 is primarily a timing difference in the commencement of actual recovery for the new investment through the ECRC mechanism. Until the in-service date for the Plant Daniel scrubbers, these projects are treated as interest bearing Construction Work in Progress. The accrual of AFUDC ceases as each scrubber is placed in-service and recovery commences through the ECRC mechanism. The Plant Daniel scrubbers were originally projected to be placed in service beginning in December 2015. As a result, the carrying cost for this investment as a component of recoverable ECRC cost was projected to begin in December 2015. Because the scrubbers are now projected to be placed in service in October and November 2015, recovery of the carrying costs as a component of recoverable ECRC cost will begin sooner than previously expected. This results in the variance associated with Line Item 1.26.

7. On page 7, the witness testifies that the variance for Line Item 1.20 is primarily due to costs that were "incurred by Gulf in determining its MATS compliance strategy for Plant Smith."
   a. Please provide an itemized list of activities and costs associated with the compliance strategy discussed by witness Vick.
   b. Please describe the steps taken by Gulf to ensure that the costs incurred were prudent and reasonable.

ANSWER:

a. Gulf incurred Plant Smith MATS related compliance strategy costs in association with two time periods. These activities and costs are summarized below:

- August 2012 through December 2012 at a cost of $44,000: Engineering analysis was performed for the Plant Smith and Plant Scholz Electrostatic Precipitators (ESP) to examine each plant's ability to comply with the new proposed MATS particulate standard. The majority of the costs were incurred from modeling studies performed by Southern Environmental, Inc. The results of the studies indicated that Plant Smith and Plant Scholz coal-fired generating units would require ESP modifications/upgrades to comply with the MATS particulate emissions standard, and the analysis provided an estimated cost for those modifications.

- April 2013 through April 2014 at a cost of $1,625,000: Engineering tests were conducted to evaluate low cost MATS compliance options with an ultra-low sulfur coal and chemical additives at Plant Smith. The testing was conducted in two phases. Phase 1 was conducted in 2013 utilizing the boiler additive "ClearChem" to reduce sulfur dioxide and mercury. Phase 2 was conducted between November 2013 and February 2014 and utilized ultra-low sulfur coal (PRB) with Dry Sorbent Injection (DSI) and Activated Carbon Injection (ACI) technologies. A variety of chemical additives were evaluated, including ACI with different compositions from various manufactures (BASF, Norit, ADA) and two DSIs (hydrated lime and "trona"). The majority of the costs were chemical purchases, handling equipment, injection equipment, water treatment and emission testing and monitoring. The purpose of the test program was to determine emission optimization and any operational impacts from the use of an ultra-low sulfur coal as a primary fuel as part of the MATS control.

b. Gulf Power has followed an on-going process to develop, review, and update environmental compliance strategies and cost projections. The goal of this process is to identify reasonable, cost-effective compliance strategies that will

minimize the impact on Gulf Power's customers while achieving environmental objectives and assuring compliance with all environmental requirements. The Plant Smith MATS compliance test plan was reviewed, accepted and permitted by the Florida Department of Environmental Protection (FDEP). Gulf completed the testing and submitted a report to the FDEP summarizing the results on April 2, 2014. Gulf has processes in place to ensure oversight in all of its environmental activities to minimize the cost of compliance to Gulf's customers.

AFFIDAVIT

STATE OF FLORIDA )
)
COUNTY OF ESCAMBIA )

Docket No. 150007-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D. Ritenour

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

MELISSA A. DARNES
MY COMMISSION # EE 150873
EXPIRES: December 17, 2015
Bonded Thru Budget Notary Services

Sworn to and subscribed before me this 25th day of September, 2015.

Melissa A. Darnes

Notary Public, State of Florida at Large

# 43

# GULF's Responses to Staff's Third Set of Interrogatories, Nos. 8-10

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 43
PARTY: STAFF
DESCRIPTION: Gulf's Responses to Staff's Third Set of Interrogatories, Nos. 8-10.[Bates
150007 Hearing Exhibit 00188

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In re: Environmental Cost Recovery Clause | ) | Docket No. 150007-EI |

GULF POWER COMPANY'S RESPONSES TO
STAFF'S THIRD SET OF INTERROGATORIES (NOS. 8-10)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Third Set of Interrogatories (Nos. 8-10) on the following pages.

Respectfully submitted by electronic mail the 28th day of September, 2015.

**JEFFREY A. STONE**
Florida Bar No. 325953
**RUSSELL A. BADDERS**
Florida Bar No. 007455
**STEVEN R. GRIFFIN**
Florida Bar No. 0627569
**BEGGS & LANE**
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
**Attorneys for Gulf Power Company**

**The following questions refer to the testimony of Witness James O. Vick, filed on August 31, 2015.**

8. On page 6, the witness testifies that "the [ELG] project costs will be recorded to a preliminary design and investigation account (deferred debit) until the rule is finalized and Gulf has determined the best option to comply with the regulation."
   a. Will the recording of this expense in the design and investigation account as a deferred debit create a regulatory asset? If yes, what Commission order provides the authority to create this regulatory asset?
   b. In proposing this accounting treatment, is Gulf asking for an order to allow it to create a regulatory asset?
   c. If this creates a regulatory asset, what is Gulf's proposed cost recovery for this asset?
   d. If this deferred debit is not a regulatory asset, what is Gulf's proposed cost recovery for this asset?

ANSWER:

   a. No.
   b. No.
   c. Not applicable.
   d. Gulf is not seeking cost recovery of ELG preliminary design and investigation costs in the 2016 period. Gulf proposes to record these costs to FERC account 183 – Preliminary Survey and Investigation. Once the EPA rule is finalized, Gulf will determine the best option to comply with the regulation, which will result in Gulf either expensing the ELG preliminary design and investigation costs or capitalizing these costs to the appropriate utility plant account.

9. On page 8, the witness testifies that "Gulf plans to replace Plant Crist's scrubber booster fan hubs, scrubber mist eliminator, and scrubber expansion joints, as well as increase the capacity of its scrubber wastewater treatment plant." Please explain why Gulf has planned the described activities.

ANSWER:

The scrubber booster fan hubs are at the end of their useful life. Booster fans have a recommended rebuild interval of every four years per the fan's manufacturer. However, based on annual inspections conducted by plant personnel and discussion with subject matter experts and the manufacturer's technical advisors, the rebuild interval was extended to six years. Fan operation started in December 2009. The recommended rebuild is currently scheduled for 2016.

The scrubber mist eliminators are now at the end of their useful life. The current mist eliminators have been in service since startup, December 2009. Visual inspections conducted in April 2015 found some modules loose and hanging, while other modules had fallen completely out.

The scrubber expansion joint (joint #1) is exhibiting signs of wear and chemical deterioration. The recommended replacement is due in 2016, at the end of its expected reliable life.

Scrubber wastewater treatment plant is expanding capacity from 230 gpm to 500 gpm to deal with excess water due to storm events. The scrubber, gypsum dewatering and gypsum storage systems are all closed loop, and the only way to blow down or reduce excess water from the system is passage through the wastewater treatment plant and into the deep well injection system.

10. On page 13, the witness testifies that the "projected 2015 and 2016 CCR O&M expenses are $13.24 million." In Gulf Power Company's Preliminary List of New Projects, filed on July 1, 2015, the Company estimated 2015 and 2016 CCR O&M expenditures of $660,000 and $250,000 respectively.
    a. Please explain what led to the estimated/projected O&M expense increase.
    b. Please describe how Gulf developed the $13.24 million estimate described by witness Vick. Also, please identify any sources relied on to develop the $13.24 million estimate.

ANSWER:

a. The CCR O&M expenditures for 2015 listed in Gulf's Preliminary List of New Projects is $62,000 not $660,000. The $660,000 is the 2015 capital expenditures. The amounts provided in Gulf Power Company's Preliminary List of New Projects were preliminary and do not include costs associated with new requirements that were identified after July 1, 2015. On pages 4 and 5 of Gulf's 2016 Projection filing, Witness Vick discusses the draft NPDES renewal permit for Plant Scholz that was issued on August 24, 2015. The permit renewal has new conditions requiring closure of Plant Scholz CCR Unit. Gulf now projects expenses to be $600,000 in 2015 and $12.2 million in 2016 for the closure activities.

b. Gulf describes how it developed its estimates for the CCR O&M for 2015 and 2016 as it relates to the $62,000 and $250,000 outlined in its Preliminary List of New Projects in Staff's Second Set of Interrogatories Item No. 2. With respect to the $12.8 million over 2015 and 2016 discussed in Item 10a for the closure of Plant Scholz CCR Unit, these dollars were developed with Gulf's consultants. The total cost of closure is estimated to be $30 million and is scheduled to be completed in 2018.

AFFIDAVIT

STATE OF FLORIDA )
)
COUNTY OF ESCAMBIA )

Docket No. 150007-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

MELISSA A. DARNES
MY COMMISSION # EE 150673
EXPIRES: December 17, 2015
Bonded Thru Budget Notary Services

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 25th day of September, 2015.

Melissa A. Darnes
Notary Public, State of Florida at Large

# 44

# Commission Staff Final Audit Report for Gulf Power Company, Dated June 11, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 44
PARTY: STAFF
DESCRIPTION: Commission Staff Final Audit Report for Gulf Power Company, dated June

FILED JUN 11, 2015
DOCUMENT NO. 03575-15
FPSC - COMMISSION CLERK

**State of Florida**

# Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

**-M-E-M-O-R-A-N-D-U-M-**

**DATE:** June 11, 2015

**TO:** Office of Commission Clerk

**FROM:** Lynn M. Deamer, Chief of Auditing, Office of Auditing and Performance Analysis

**RE:** Docket No.: 150007-EI
Company Name: Gulf Power Company
Company Code: EI804
Audit Purpose: Environmental Cost Recovery Clause
Audit Control No: 15-014-1-1

Attached is the final audit report for the Utility stated above. I am sending the Utility a copy of this memo and the audit report. If the Utility desires to file a response to the audit report, it should send a response to the Office of Commission Clerk. There is no confidential work papers associated with this audit.

LMD/cp

Attachment: Audit Report

cc: Office of Auditing and Performance Analysis File

**State of Florida**

# Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tallahassee District Office

## Auditor's Report

Gulf Power Company
Environmental Cost Recovery Clause

**Twelve Months Ended December 31, 2014**

Docket No. 150007-EI
Audit Control No. 15-014-1-1
**June 8, 2015**

Donna D. Brown
Audit Manager

Lynn M. Deamer
Reviewer

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150007 Hearing Exhibits 00147

## Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Engineering in its audit service request dated January 14, 2015. We have applied these procedures to the attached summary exhibit and to several related schedules prepared by Gulf Power Company in support of its 2014 filing for the Environmental Cost Recovery Clause in Docket No. 150007-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

## Objectives and Procedures

## General

Definition

Utility refers to the Gulf Power Company.
ECRC refers to the Environmental Cost Recovery Clause.

## Capital Investments

Utility Plant in Service

**Objectives:** The objectives were to verify all ECRC project-related plant additions, retirements and adjustments for the period January 1, 2014, through December 31, 2014.

**Procedure:** We reconciled Plant in Service (Line 2) and Accumulated Depreciation (Line 3) to the general ledger for each capital project listed on the 2014 Form 42-8A. No exceptions were noted.

Construction Work in Progress

**Objective:** The objective was to verify net investments associated with the following capital projects, and to determine whether any project which involved the replacement or retirement of an existing plant asset is retired at the installed costs by the Utility in accordance with Rule 25-6.0142(4) (b), F.A.C.

1) Air Quality Compliance Program
2) Smith Water Conservation
3) Crist FDEP Agreement for Ozone Attainment

**Procedures:** We selected a sample of the additions to the capital projects for review. We determined whether additions had appropriate supporting documentation and were recorded to the correct project and account. We determined whether items that were replaced had a corresponding retirement, which was recorded in accordance with Rule 25-6.0142(4) (b), F.A.C. We reconciled Construction Work in Progress Non-Interest Bearing amounts on Form 42-8A to the general ledger. No exceptions were noted.



150007 Hearing Exhibits 00149

## Revenue

Operating Revenues

**Objectives:** The objectives were to determine the actual Kilowatt Hours (KWH) sold for the period January 1, 2014, through December 31, 2014, and whether the Utility applied the Commission approved cost recovery factor to actual KWH sales.

**Procedures:** We reconciled the 2014 filing to the Utility's monthly Environmental Revenue Reports. We selected a sample of residential and commercial customers' bills and recalculated each to verify the use of the approved tariff rate. This work was performed jointly with the revenue portions of the other clause audits of the Utility. The work product is contained in Docket No. 150001-EI, Audit Control No. 15-023-1-1. No exceptions were noted.

## Expense

Operation and Maintenance Expense

**Objectives:** The objectives were to verify that Operation and Maintenance (O&M) Expense listed on the Utility's Form 42-5A filing was supported by adequate documentation and that the expenses are appropriately recoverable through the ECRC.

**Procedures:** We traced expenses in the filing to the general ledger. We judgmentally selected a sample of O&M Expenses for testing. The source documentation for selected items was reviewed to ensure the expense was related to the ECRC and that the expense was charged to the correct accounts. No exceptions were noted.

Depreciation and Amortization

**Objective:** The objective was to verify that the most recent Commission approved depreciation rates or amortization periods were used in calculating Depreciation Expense.

**Procedures:** We recalculated Depreciation Expense on a test basis. We traced total year Depreciation Expense for each capital project listed on Form 42-8A to the general ledger detail. No exceptions were noted.

## Other Issues

$SO_2$ and NOx Allowances

**Objectives:** The objectives were to verify investments, inventory, expensed amounts, allowance auction proceeds and to verify amounts included in Working Capital, Form 42-8A.

**Procedures:** We traced 2014 consumption for $SO_2$ Allowances, net of Gains on Sales of Emission Allowances, from the Utility's detailed Allowances Reports to the Total Emissions Schedule on Form 42-8A. We reconciled the inventory amounts in the general ledger to the Working Capital Calculation on Form 42-8A. No exceptions were noted.



150007 Hearing Exhibits 00150

## True-up

**Objective:** The objective was to determine if the True-Up and Interest Provision as filed on Form 42-2A was properly calculated.

**Procedures:** We traced the December 31, 2013, True-Up Provision to the Commission Order. We recalculated the True-Up and Interest Provision amounts as of December 31, 2014, using the Commission approved beginning balance as of December 31, 2013, the Financial Commercial Paper rates, and the 2014 ECRC revenues and costs. No exceptions were noted.

## Analytical Review

**Objective:** The objective was to perform an analytical review of the Utility's ECRC Revenues and Expenses to determine if there were any material changes or inconsistencies from the prior year.

**Procedures:** We compared 2014 to 2013 revenues and expenses. We requested explanations from the Utility for significant variances. Explanations provided were sufficient. Further follow-up was not required.

## Audit Findings

**None**



150007 Hearing Exhibits 00152

# Exhibit

## Exhibit 1: True-Up

Schedule2A

Gulf Power Company Environmental Cost Recovery Clause (ECRC) Calculation of the Final True-Up Amount January 2014- December 2014

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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ECRC Revenues (net of Revenue Taxes) | 14,427,037 | 9,814,540 | 10,171,868 | 9,839,795 | 12,280,824 | 14,558,539 | 15,631,370 | 16,134,629 | 13,508,428 | 11,125,702 | 10,398,403 | 10,527,797 | 148,418,933 |
| | True-Up Provision (Order No. PSC-13-0606-FOF-EO | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,073) | (649,075) | (7,788,878) |
| | ECRC Revenues Applicable to Period (Lines 1 + 2) | 13,777,964 | 9,165,467 | 9,522,795 | 9,190,722 | 11,631,751 | 13,909,466 | 14,982,297 | 15,485,556 | 12,859,355 | 10,476,629 | 9,749,330 | 9,878,722 | 140,630,055 |
| 4 | Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| | a O & M Activities (Schedule 5A, Line 9) | 3,086,570 | 2,747,697 | 2,239,814 | 1,774,143 | 2,347,923 | 1,714,073 | 3,271,590 | 2,532,730 | 1,867,003 | 2,439,332 | 1,692,133 | 2,679,685 | 28,392,693 |
| | b Capital Investment Projects (Schedule 7A, Line 9) | 9,693,176 | 9,677,372 | 9,658,895 | 9,645,777 | 9,629,014 | 9,601,653 | 9,565,150 | 9,551,708 | 9,538,634 | 9,528,466 | 9,748,775 | 9,532,429 | 115,371,046 |
| | c Total Jurisdictional ECRC Costs | 12,779,746 | 12,425,069 | 11,898,709 | 11,419,920 | 11,976,937 | 11,315,726 | 12,836,740 | 12,084,438 | 11,405,637 | 11,967,798 | 11,440,908 | 12,212,114 | 143,763,739 |
| | Over/(Under) Recovery (Line 3 - Line 4c) | 998,218 | (3,259,602) | (2,375,914) | (2,229,198) | (345,185) | 2,593,740 | 2,145,558 | 3,401,118 | 1,453,719 | (1,491,168) | (1,691,578) | (2,333,392) | (3,133,684) |
| | Interest Provision (Schedule 3A, Line 10) | (858) | (817) | (943) | (1,129) | (1,169) | (906) | (688) | (600) | (422) | (359) | (478) | (671) | (9,040) |
| | Beginning Balance True-Up & Interest Provision | | | | | | | | | | | | | |
| | a Actual Total for True-Up Period 2013 | (10,730,771) | (9,084,337) | (11,695,683) | (13,423,467) | (15,004,721) | (14,702,002) | (11,460,095) | (8,666,153) | (4,616,561) | (2,514,191) | (3,356,645) | (4,399,628) | (10,730,771) |
| | b Final True-Up from January2012- December 2012 (Order No. PSC-13-0606-FOF-EO | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) | (3,704,022) |
| | True-Up Collected/(Refunded) (see Line 2) | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,073 | 649,075 | 7,788,878 |
| | Adjustments | | | | | | | | | | | | | |
| 10 | End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8 + 9) | (12,788,359) | (15,399,705) | (17,127,489) | (18,708,743) | (18,406,024) | (15,164,117) | (12,370,175) | (8,320,583) | (6,218,213) | (7,060,667) | (8,103,650) | (9,788,638) | (9,788,638) |



150007 Hearing Exhibits 00153

# 45

# Gulf Power Company notification of new environmental projects, Dated July 1, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 45
PARTY: STAFF
DESCRIPTION: Gulf Power Company notification of new environmental projects,

FILED JUL 01, 2015
DOCUMENT NO. 04053-15
FPSC - COMMISSION CLERK

**Robert L. McGee, Jr.**
Regulatory & Pricing Manager

One Energy Place
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RLMCGEE@southernco.com

GULF POWER
A SOUTHERN COMPANY

July 1, 2015

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

Re: Docket No. 150007-EI - Preliminary List of New Projects

Dear Ms. Stauffer:

Attached is Gulf Power Company's Preliminary List of New Projects, to be filed in the above-referenced Environmental Cost Recovery Clause docket. Pursuant to the Order Establishing Procedure, a copy of this Preliminary List of New Projects prepared using Microsoft Word is being provided to Commission staff and all parties.

Sincerely,

Robert L. McGee, Jr.
Regulatory and Pricing Manager

md

Attachments

cc: Beggs & Lane
Jeffrey A. Stone, Esq.

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

# ENVIRONMENTAL COST RECOVERY CLAUSE

# DOCKET NO. 150007-EI

PRELIMINARY LIST-
NEW PROJECTS FOR COST RECOVERY

FOR THE PERIOD
JANUARY 2016 – DECEMBER 2016

July 1, 2015

GULF POWER

A SOUTHERN COMPANY

**Project:**
Effluent Limitations Guidelines

**Law/Regulation Requiring Project:**
In June 2013, the EPA published a proposed Effluent Limitations Guidelines (ELG) rule which requested comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants and best management practices for Coal Combustion Residual (CCR) surface impoundments. The rule is located in Title 40 Code of Federal Regulations (CFR) Part 423. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015.

**Description:**
During the 2015-2016 timeframe Gulf plans to complete water balance and design studies to further evaluate the impact of the proposed ELG regulatory options. The project costs will be booked to a preliminary design and investigation account (deferred debit) until the rule is finalized and Gulf determines the best option to comply with the regulation.

The proposed ELG regulations could require the installation of additional controls such as wastewater treatment systems and/or dry ash handling systems at Gulf's generating facilities. The ultimate impact of these proposed regulations will, however, depend on the specific requirements of the final rule.

**Estimated 2016 Capital Expenditures**: To be determined
**Estimated 2016 O&M Expenses**: $175,000 ± 20%

**Project:**
Coal Combustion Residuals

**Law/Regulation Requiring Project:**

On April 17, 2015 EPA published the final Coal Combustion Residuals (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 will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards.

By the effective date of the rule, October 19, 2015, any CCR unit subject to the federal rule must have a publicly available website established, weekly and monthly inspections initiated, and a fugitive dust plan prepared. Additional compliance reporting and demonstrations will be required throughout the life of the CCR unit including groundwater monitoring and potential corrective actions during the 2016-2018 timeframe.

**Description:**
During 2015 Gulf will move forward with the following activities related to compliance with the new CCR regulation: revising the weekly and monthly CCR inspection program, developing a publically available website that will serve as the compliance record for the CCR regulation, installing permanent markers at all CCR ponds, preparing a fugitive dust control plan, developing and installing a new groundwater monitoring system, and performing annual professional engineer (PE) inspections of the CCR impoundments and landfills.

In 2016 Gulf will prepare closure and post-closure care plans for the CCR pond and landfills, conduct hydrologic and hydraulic capacity studies of the CCR ponds, compile a history of the structural integrity reports and design information for the CCR units, and conduct annual professional engineering (PE) and dust control inspections as well as groundwater monitoring. In addition, sites are required to address run-on and run-off of stormwater from CCR units.

The projected 2015 capital expenditures include installation of additional groundwater monitoring systems required for Plant Crist, Plant Smith, and Plant Daniel. The proposed 2016 capital expenditures are associated with installation of a new dry bottom ash handling system for Plant Crist as well as new CCR wastewater management systems for Plant Crist and Plant Smith.

**Estimated 2015 Capital Expenditures: $660,000 ± 20%**
**Estimated 2015 O&M Expenses: $62,000± 20%**

**Estimated 2016 Capital Expenditures: $9.3 Million ± 20%**
**Estimated 2016 O&M Expenses: $250,000 ± 20%**

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: **Environmental Cost Recovery Clause** )

Docket No.: **150007-EI**

**CERTIFICATE OF SERVICE**

I HEREBY CERTIFY that a true copy of the foregoing was furnished by electronic mail this 1st day of July, 2015 to the following:

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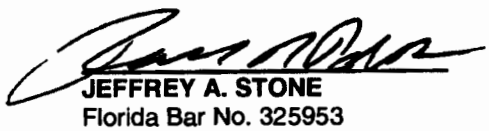

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**Attorneys for Gulf Power**

EXHIBIT NO. 46

DOCKET NO: 150007-EI

WITNESS: None – stipulated exhibit

PARTY: OPC & Gulf Power Co.

DESCRIPTION: Deferral stipulation for the Plant Scholz CCR Unit I (Issue 11A)

DOCUMENTS: Transmittal e-mail and stipulation language

PROFFERED BY: OPC

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150007-EI EXHIBIT: 46
PARTY: OPC/Gulf
DESCRIPTION: Deferral Stipulation for Plant Scholz CCR Unit 1

| | |
|---|---|
| **From:** | Jeffrey Stone |
| **To:** | "Charles Murphy" |
| **Cc:** | Rehwinkel, Charles (REHWINKEL.CHARLES@leg.state.fl.us); Russell Badders |
| **Bcc:** | Stone, Jeffrey A. (x2jstone@southernco.com) |
| **Subject:** | RE: 150007 draft prehearing order |
| **Date:** | Thursday, October 29, 2015 8:33:00 AM |
| **Importance:** | High |

Charlie,

This follows separate telephone conversations Charles Rehwinkel and I have each had with you last night and/or this morning. As you now know, OPC and Gulf have been working on and have now achieved an agreement that will allow the only remaining contested issue for Gulf (Issue 11A) to be shown as a Type 2 stipulation and further allow Gulf witnesses Vick and Boyett to be excused from next week's scheduled hearing in this docket. The agreement between OPC and Gulf is set forth below:

> Subsequent to the prehearing conference held on October 19, 2015, representatives from both Gulf Power and the Office of Public Counsel have continued their discussions in an effort to reach agreement on the aspect of Issue 11A related to the recovery of Scholz CCR closure costs through the ECRC mechanism. All other aspects of Issue 11A are eligible for "Type 2" stipulation. Gulf and OPC have agreed to jointly request deferral of the Scholz CCR closure cost issue to a future proceeding either in the ongoing ECRC docket or in a separate spin-off limited scope proceeding. In the event the issue being deferred is addressed in a separate spin-off docket, the parties agree that the hearing should not occur until after Gulf submits an actual closure plan to the FDEP for its review and approval under the applicable NPDES permit. Whether or not the hearing on the deferred issue occurs in the ongoing ECRC docket or in a separate spin-off docket, OPC will be allowed to litigate its concerns in such hearing over (1) eligibility of the Scholz CCR closure costs for ECRC recovery, (2) prudence of such costs, and/or (3) assurances that there is no duplication of cost recovery already provided for in mechanisms other than ECRC. In order to preserve the relative positions of the parties pending such future proceeding, and to minimize the total costs ultimately recovered from Gulf's customers in the event that Gulf ultimately prevails on the deferred issue regarding ECRC recovery, OPC and Gulf agree that the projections of costs for Scholz CCR closure included in Gulf's proposed cost recovery rates for 2016 shall remain in the total amount on which the proposed 2016 cost recovery rates are based pending the ultimate resolution of the issue deferred through this agreement. Such amounts collected through the 2016 cost recovery rates will be trued up with interest upon final resolution of the deferred issue, such true up to occur through the true up processes provided in the ECRC mechanism. As a result of this agreement to defer the Scholz CCR closure cost issue, the only remaining impediment to excusing Gulf witnesses Vick and Boyett is hereby removed, and their testimony and exhibits shall be inserted into the record without objection as a basis for recovery pending ultimate resolution of the issues deferred as set forth above. Although the testimony and exhibits of Gulf witness Vick is hereby stipulated into the record, there shall be no presumption of correctness applied to such evidence by virtue of this stipulation.

As you and I discussed this morning, we are working on incorporating this agreement into a broader

statement for the prehearing order intended to show Issue 11A as a type 2 stipulation. We expect to have that broader statement ready to circulate in a few minutes. Thanks for your patience and assistance.

Jeff

Agreement to defer Scholz CCR closure cost issue to a future proceeding:

Subsequent to the prehearing conference held on October 19, 2015, representatives from both Gulf Power and the Office of Public Counsel have continued their discussions in an effort to reach agreement on the aspect of Issue 11A related to the recovery of Scholz CCR closure costs through the ECRC mechanism. All other aspects of Issue 11A are eligible for "Type 2" stipulation. Gulf and OPC have agreed to jointly request deferral of the Scholz CCR closure cost issue to a future proceeding either in the ongoing ECRC docket or in a separate spin-off limited scope proceeding. In the event the issue being deferred is addressed in a separate spin-off docket, the parties agree that the hearing should not occur until after Gulf submits an actual closure plan to the FDEP for its review and approval under the applicable NPDES permit. Whether or not the hearing on the deferred issue occurs in the ongoing ECRC docket or in a separate spin-off docket, OPC will be allowed to litigate its concerns in such hearing over (1) eligibility of the Scholz CCR closure costs for ECRC recovery, (2) prudence of such costs, and/or (3) assurances that there is no duplication of cost recovery already provided for in mechanisms other than ECRC. In order to preserve the relative positions of the parties pending such future proceeding, and to minimize the total costs ultimately recovered from Gulf's customers in the event that Gulf ultimately prevails on the deferred issue regarding ECRC recovery, OPC and Gulf agree that the projections of costs for Scholz CCR closure included in Gulf's proposed cost recovery rates for 2016 shall remain in the total amount on which the proposed 2016 cost recovery rates are based pending the ultimate resolution of the issue deferred through this agreement. Such amounts collected through the 2016 cost recovery rates will be trued up with interest upon final resolution of the deferred issue, such true up to occur through the true up processes provided in the ECRC mechanism. As a result of this agreement to defer the Scholz CCR closure cost issue, the only remaining impediment to excusing Gulf witnesses Vick and Boyett is hereby removed, and their testimony and exhibits shall be inserted into the record without objection as a basis for recovery pending ultimate resolution of the issues deferred as set forth above. Although the testimony and exhibits of Gulf witness Vick is hereby stipulated into the record, there shall be no presumption of correctness applied to such evidence by virtue of this stipulation.