Matthew R. Bernier
Associate General Counsel

August 27, 2021

**VIA ELECTRONIC FILING**

Adam J. Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: *Environmental Cost Recovery Clause*; Docket No. 20210007-EI

Dear Mr. Teitzman:

On behalf of Duke Energy Florida, LLC, please find enclosed for electronic filing in the above-referenced Docket:

- DEF's Petition for Approval of Environmental Cost Recovery True-Up and 2022 Environmental Cost Recovery Clause Factors;
- Direct Testimony of Gary P. Dean and Exhibit No.___(GPD-5);
- Direct Testimony of Kim Spence McDaniel;
- Direct Testimony of Timothy Hill; and
- Direct Testimony of Reginald Anderson.

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/cmw
Enclosures

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**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

| | |
|---|---|
| In re: Environmental Cost Recovery Clause | Docket No. 20210007-EI<br>Dated: August 27, 2021 |

**DUKE ENERGY FLORIDA'S PETITION FOR APPROVAL OF ENVIRONMENTAL COST RECOVERY TRUE-UP AND 2022 ENVIRONMENTAL COST RECOVERY CLAUSE FACTORS**

Duke Energy Florida, LLC ("DEF" or "the Company"), hereby petitions for approval of its environmental cost recovery true-up and proposed Environmental Cost Recovery Clause ("ECRC") factors for the period January 2022 to December 2022. In support of this Petition, the Company states:

1. The total true-up applicable for this period is an over-recovery of $1,828,238. This consists of the final true-up over-recovery of $231,488 for the period from January 2020 through December 2020 and an estimated true-up over-recovery of $1,596,750 for the current period of January 2021 through December 2021. Documentation supporting the total true-up over-recovery is provided in the Direct Testimony of Gary P. Dean and Exhibit No.__(GPD-3), submitted on July 30, 2021, and Mr. Dean's testimony and Exhibit No.__(GPD-5) submitted contemporaneously with this Petition. Additional cost information for specific ECRC programs for the period January 2021 through December 2021 are presented in the July 30, 2021, pre-filed testimonies of Reginald Anderson, Timothy Hill and Kim McDaniel.

2. As explained in Mr. Dean's testimony submitted with this Petition and shown on Form 42-1P, Line 4 of Mr. Dean's Exhibit No.__(GPD-5), the total projected jurisdictional capital and O&M costs for the period January 2022 through December 2022 are $10,448,824. Projected costs for specific ECRC programs for the period January 2022 through December 2022 are

presented in the pre-filed testimonies of Mr. Anderson, Mr. Dean, Mr. Hill and Ms. McDaniel, submitted with this Petition.

3. DEF's proposed ECRC factors for the period January 2022 to December 2022, which are designed to recover the 2020 final true-up, 2021 actual/estimated true-up and projected 2022 costs, are presented for the Commission's review and approval in Mr. Dean's testimony and supporting exhibits submitted with this Petition.

4. The environmental cost recovery true-up and proposed ECRC factors presented in Mr. Dean's testimony and exhibits are consistent with the provisions of Section 366.8255, Florida Statutes, and with prior rulings by the Commission.

WHEREFORE, DEF respectfully requests that the Commission approve the Company's environmental cost recovery true-up and proposed ECRC factors for the period January 2022 through December 2022 as set forth in the testimony and supporting exhibits of Mr. Dean filed contemporaneously with this Petition.

Respectfully submitted this 27th day of August, 2021.

*/s/ Matthew R. Bernier*

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**CERTIFICATE OF SERVICE**

*Docket No. 20210007-EI*

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 27th day of August, 2021.

*/s/ Matthew R. Bernier*
Attorney

| | |
|---|---|
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**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

DIRECT TESTIMONY OF

GARY P. DEAN

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

August 27, 2021

**Q. Please state your name and business address.**

A. My name is Gary P. Dean. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

**Q. Have you previously filed testimony before this Commission in Docket No. 20210007-EI?**

A. Yes. I provided direct testimony on April 1, 2021, and July 30, 2021.

**Q. Has your job description, education, background or professional experience changed since that time?**

A. No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to present, for Commission review and approval, Duke Energy Florida, LLC's ("DEF" or "the Company") calculation of revenue

requirements and Environmental Cost Recovery Clause ("ECRC") factors for customer billings for the period January 2022 through December 2022. My testimony also addresses capital and O&M expenses for DEF's environmental compliance activities for the year 2022.

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

A. Yes. I am sponsoring the following exhibit:

Exhibit No.__(GPD-5), which consists of PSC Forms 42-1P through 42-8P The individuals listed below are co-sponsors of Forms 42-5P, pp. 1 through 4, and 6 through 23 as indicated in their Direct Testimonies. I am sponsoring Form 42-5P, p. 5.

- Ms. McDaniel will co-sponsor Forms 42-5P, pp. 1 through 4, 6 and 8 through 19.
- Mr. Anderson and Ms. McDaniel will co-sponsor Form 42-5P, p. 7.
- Mr. Anderson will co-sponsor Form 42-5P, pp. 20 through 22.
- Mr. Hill will co-sponsor Form 42-5P, p. 23.

**Q. Please summarize your testimony.**

A. My testimony supports the approval of an average ECRC billing factor of 0.027 cents per kWh, which includes projected jurisdictional capital and O&M revenue requirements for the period January 2022 through December 2022 of approximately $12.3 million associated with a total of 18 environmental projects,

and a true-up over-recovery provision of approximately $1.8 million from prior periods. My testimony also supports that projected environmental expenditures for 2022 are appropriate for recovery through the ECRC.

**Q. What is the total recoverable revenue requirement for the period January 2022 through December 2022?**

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is approximately $10.4 million as shown on Form 42-1P, line 4 of Exhibit No.__(GPD-5).

**Q. What is the total true-up to be applied for the period January 2022 through December 2022?**

A. The total true-up applicable to this period is an over-recovery of approximately $1.8 million. This amount consists of the final true-up over-recovery of approximately $231 thousand for the period January 2020 through December 2020, and an estimated true-up over-recovery of approximately $1.6 million for the current period of January 2021 through December 2021. The detailed calculation supporting the 2021 estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No.__(GPD-3) filed with the Commission on July 30, 2021.

**Q. Are all the costs listed on Forms 42-1P through 42-7P attributable to environmental compliance programs previously approved by the**

**Commission?**

A. Yes, the following ECRC programs were previously approved by the Commission:

The Substation and Distribution System Programs (Project 1 & 2) were previously approved in Order No. PSC-2002-1735-FOF-EI.

The Pipeline Integrity Management Program (Project 3) and the Above Ground Tank Secondary Containment Program (Project 4) were previously approved in Order No. PSC-2003-1348-FOF-EI.

The recovery of Sulfur Dioxide ($SO_2$) Emission Allowances (Project 5) was previously approved in Order No. PSC-1995-0450-FOF-EI; however, the costs were moved to the ECRC docket from the Fuel docket beginning January 1, 2004, at the request of Staff to be consistent with the other Florida investor-owned utilities.

CAIR was replaced by the Cross-State Air Pollution Rule on January 1, 2015. Consistent with Order No. PSC-2011-0553-FOF-EI, DEF treated the costs associated with unusable NOx emission allowances as a regulatory asset and amortized it over three (3) years, beginning January 1, 2015, until fully recovered on December 31, 2017, with a return on the unamortized investment.

The Phase II Cooling Water Intake 316(b) Program (Project 6) was previously approved in Order No. PSC-2004-0990-PAA-EI, PSC-2018-0014-FOF-EI and PSC-2020-0433-FOF-EI.

DEF's Integrated Clean Air Compliance Plan (Project 7) was approved by the Commission as a prudent and reasonable means of complying with the Clean Air Interstate Rule and related regulatory requirements in Order No. PSC-2007-0922-FOF-EI.

The Arsenic Groundwater Standard Program (Project 8), Sea Turtle Lighting Program (Project 9) and Underground Storage Tanks Program (Project 10) were previously approved in Order No. PSC-2005-1251-FOF-EI.

The Modular Cooling Tower Project (Project 11) was previously approved in Order No. PSC-2007-0722-FOF-EI.

The Crystal River Thermal Discharge Compliance Project (Project 11.1) and Greenhouse Gas Inventory and Reporting Project (Project 12) were previously approved in Order No. PSC-2008-0775-FOF-EI.

The Mercury Total Maximum Loads Monitoring Program (Project 13) was previously approved in Order No. PSC-2009-0759-FOF-EI.

The Hazardous Air Pollutants (HAPs) ICR Program (Project 14) was previously approved in Order No. PSC-2010-0099-PAA-EI.

The Effluent Limitations Guidelines ICR Program (Project 15) was previously approved in Order No. PSC-2010-0683-PAA-EI.

The Effluent Limitations Guidelines Program (Project 15.1) was previously approved in Order No. PSC-2013-0606-FOF-EI.

The National Pollutant Discharge Elimination System (NPDES) Program (Project 16) was previously approved in Order No. PSC-2011-0553-FOF-EI.

The Mercury & Air Toxic Standards (MATS) Program (Project 17), which replaces Maximum Achievable Control Technology (MACT), was previously approved in Order Nos. PSC-2011-0553-FOF-EI, PSC-2012-0432-PAA-EI and PSC-2014-0173-PAA-EI.

The Coal Combustion Residual (CCR) Rule (Project 18) was previously approved in Order No. PSC-2015-0536-FOF-EI, Order No. PSC-2018-0594-FOF-EI, and Order No. PSC-2019-0500-FOF-EI.

**Q. Does the 2022 Projection Filing comply with the 2021 Settlement Agreement approved by the Commission in Order No. PSC-2021-0202-AS-EI?**

A. Yes. All matters in the 2021 Settlement Agreement have been incorporated into the filing.

**Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2022?**

A. Yes. Form 42-2P of Exhibit No.__(GPD-5) summarizes recoverable jurisdictional O&M cost estimates for these projects of approximately $8.2 million.

**Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2022?**

A. Yes. Form 42-3P of Exhibit No.__(GPD-5) summarizes recoverable jurisdictional capital cost estimates for these projects of approximately $4.1 million. Form 42-4P, pp. 1 through 9, show detailed calculations of these costs.

**Q. Have you prepared schedules providing progress reports for all environmental compliance projects?**

A. Yes. Form 42-5P, pp. 1 through 23 of Exhibit No.__(GPD-5), provide a description, progress summary and recoverable cost estimates for each project.

**Q. What are the total projected jurisdictional costs for environmental compliance projects for the year 2022?**

A. The total jurisdictional capital and O&M costs to be recovered through the ECRC

are approximately $12.3 million. The costs are calculated on Form 42-1P, line 1c of Exhibit No.__(GPD-5).

**Q. Please describe how the proposed ECRC factors are developed.**

A. The ECRC factors are calculated on Forms 42-6P and 42-7P of Exhibit No.__(GPD-5). The demand component of class allocation factors is calculated by determining the percentage each rate class contributes to monthly system peaks adjusted for losses for each rate class, which is obtained from DEF's load research study filed with the Commission in July 2021. The energy allocation factors are calculated by determining the percentage each rate class contributes to total kilowatt-hour sales adjusted for losses for each rate class. Form 42-7P presents the calculation of the proposed ECRC billing factors by rate class.

**Q. What effect does the 2021 Settlement Agreement Order No. PSC-2021-0202-AS-EI, dated June 4, 2021, have on the ECRC O&M and Capital Investments presented in this Docket (20210007-EI)?**

A. Pursuant to the 2021 Settlement Agreement in Docket 20210016-EI and approved in Order PSC-2021-0202-AS-EI, DEF will move the ECRC costs identified in Exhibit 2 of the 2021 Settlement Agreement to base rates as of year-end 2021. The Settlement Agreement provides that effective with the first billing cycle of January 2022, DEF is authorized to remove the Capital and/or O&M ECRC recovery associated with Above Ground Secondary Containment (Projects 4.1, 4.2, 4.3), CAIR/CAMR Peaking (Project 7.2), CAIR/CAMR Crystal River AFUDC Base

(Project 7.4), CAIR/CAMR Crystal River AFUDC A&G (Project 7.4), CAIR/CAMR Crystal River Conditions of Certification (Project 7.4), Sea Turtle Coastal Street Lighting (Project 9), Underground Storage Tanks (Projects 10.1, 10.2) and Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion (Project 17.1), and transfer those to base rates in an amount which will equal the annual retail revenue requirements of the assets in-service as of December 31, 2021. The investments that are not included in the 2021 Settlement Agreement as moving to base will continue to be recovered through ECRC in future Dockets.

**Q. What are DEF's proposed 2022 ECRC billing factors by the various rate classes and delivery voltages?**

A. The calculation of DEF's proposed ECRC factors for 2022 customer billings is shown on Form 42-7P in Exhibit No.__(GPD-5) as follows:

(Information found on the following page.)

| RATE CLASS | ECRC FACTORS |
|---|---|
| Residential | 0.028 cents/kWh |
| General Service Non-Demand | |
| @ Secondary Voltage | 0.027 cents/kWh |
| @ Primary Voltage | 0.027 cents/kWh |
| @ Transmission Voltage | 0.026 cents/kWh |
| General Service 100% Load Factor | 0.024 cents/kWh |
| General Service Demand | |
| @ Secondary Voltage | 0.025 cents/kWh |
| @ Primary Voltage | 0.025 cents/kWh |
| @ Transmission Voltage | 0.025 cents/kWh |
| Curtailable | |
| @ Secondary Voltage | 0.022 cents/kWh |
| @ Primary Voltage | 0.022 cents/kWh |
| @ Transmission Voltage | 0.022 cents/kWh |
| Interruptible | |
| @ Secondary Voltage | 0.023 cents/kWh |
| @ Primary Voltage | 0.023 cents/kWh |
| @ Transmission Voltage | 0.023 cents/kWh |
| Lighting | 0.020 cents/kWh |

**Q. When is DEF requesting that the proposed ECRC billing factors be effective?**

A. DEF is requesting that its proposed ECRC billing factors be effective with the

first billing cycle of January 2022 and continue through the last billing cycle of December 2022.

**Q. Does this conclude your testimony?**

A. Yes.

# DUKE ENERGY FLORIDA, LLC
# Environmental Cost Recovery Clause
# Commission Forms 42-1P Through 42-8P

## January 2022 - December 2022
## Calculation of Projected Period Amount

## Docket No. 20210007-EI

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2022 - December 2022**

| 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) | $7,851,653 | $0 | $0 | $317,302 | $8,168,955 |
| b | Projected Capital Projects (Form 42-3P, Lines 7 through 9) | 864,083 | 0 | 0 | 3,244,024 | 4,108,106 |
| c | Total Jurisdictional Rev Req for the Projected Period (Lines 1a + 1b) | 8,715,736 | 0 | 0 | 3,561,326 | 12,277,061 |
| 2 | True-up for Estimated Over/(Under) Recovery for the Current Period January 2021 - December 2021 (Form 42-2E, Line 5 + 6 + 10) | 1,710,639 | 1,924 | 646 | (116,460) | 1,596,750 |
| 3 | Final True-up for the Period January 2020 - December 2020 (Form 42-1A, Line 3) | 217,889 | 264 | 7 | 13,327 | 231,488 |
| 4 | Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection Period January 2022 - December 2022 (Line 1 - Line 2 - Line 3) | $6,787,207 | ($2,188) | ($654) | $3,664,458 | $10,448,824 |

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2022 - December 2022**

**O&M Activities**
**(in Dollars)**

| Line | Description | Estimated Jan-22 | Estimated Feb-22 | Estimated Mar-22 | Estimated Apr-22 | Estimated May-22 | Estimated Jun-22 | Estimated Jul-22 | Estimated Aug-22 | Estimated Sep-22 | Estimated Oct-22 | Estimated Nov-22 | Estimated Dec-22 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | O&M Activities - System | | | | | | | | | | | | | |
| 1 | Transmission Substation Environmental Investigation, Remediation and Pollution Prevention | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1a | Distribution Substation Environmental Investigation, Remediation and Pollution Prevention | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | Distribution System Environmental Investigation, Remediation and Pollution Prevention | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | Above Ground Tank Secondary Containment - Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | SO2/NOx Emissions Allowances - Energy | 986 | 967 | 1,553 | 1,182 | 1,289 | 1,289 | 1,433 | 1,350 | 1,262 | 1,312 | 662 | 848 | 14,134 |
| 6 | Phase II Cooling Water Intake 316(b) - Base | 0 | 0 | 0 | 20,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20,000 |
| 6a | Phase II Cooling Water Intake 316(b) - Intm | 0 | 20,833 | 20,833 | 20,834 | 20,833 | 20,833 | 20,834 | 0 | 10,000 | 85,000 | 20,000 | 20,000 | 260,000 |
| 7.2 | CAIR/CAMR - Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.4 | CAIR/CAMR Crystal River - Base | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.4 | CAIR/CAMR Crystal River - Energy | 531,503 | 541,537 | 763,587 | 600,363 | 740,384 | 689,863 | 725,279 | 753,530 | 724,758 | 689,409 | 357,556 | 442,456 | 7,560,224 |
| 7.4 | CAIR/CAMR Crystal River - A&G | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.4 | CAIR/CAMR Crystal River - Conditions of Certification - Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.5 | Best Available Retrofit Technology (BART) - Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Arsenic Groundwater Standard - Base | 5,367 | 5,367 | 5,367 | 5,367 | 5,367 | 5,367 | 5,367 | 5,367 | 5,367 | 10,367 | 10,367 | 5,367 | 74,401 |
| 9 | Sea Turtle - Coastal Street Lighting - Distrib | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | Modular Cooling Towers - Base | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | Greenhouse Gas Inventory and Reporting - Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Mercury Total Daily Maximum Loads Monitoring - Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Hazardous Air Pollutants (HAPs) ICR Program - Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | Effluent Limitation Guidelines ICR Program - Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15.1 | Effluent Limitation Guidelines Program CRN - Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Energy | 0 | 0 | 0 | 4,700 | 6,100 | 0 | 0 | 0 | 9,800 | 4,700 | 6,100 | 0 | 31,400 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 20,000 | 63,500 | 89,500 | 0 | 9,091 | 0 | 0 | 0 | 0 | 9,091 | 0 | 0 | 191,182 |
| 17.1 | Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17.2 | Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | Coal Combustion Residual (CCR) Rule - Energy | 16,486 | 40,986 | 24,486 | 18,986 | 54,986 | 21,486 | 16,486 | 18,986 | 16,486 | 16,486 | 37,486 | 59,486 | 342,830 |
| 2 | Total O&M Activities - Recoverable Costs | $574,342 | $673,190 | $905,326 | $671,432 | $838,049 | $738,837 | $769,398 | $779,232 | $767,673 | $816,365 | $432,171 | $528,157 | $8,494,170 |
| 3 | Recoverable Costs Allocated to Energy | 568,975 | 646,990 | 879,126 | 625,232 | 811,849 | 712,637 | 743,197 | 773,865 | 752,306 | 720,998 | 401,804 | 502,790 | 8,139,770 |
| 4 | Recoverable Costs Allocated to Demand - Transm | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Recoverable Costs Allocated to Demand - Distrib | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Recoverable Costs Allocated to Demand - Prod-Base | 5,367 | 5,367 | 5,367 | 25,367 | 5,367 | 5,367 | 5,367 | 5,367 | 5,367 | 10,367 | 10,367 | 5,367 | 94,401 |
| | Recoverable Costs Allocated to Demand - Prod-Intm | 0 | 20,833 | 20,833 | 20,834 | 20,833 | 20,833 | 20,834 | 0 | 10,000 | 85,000 | 20,000 | 20,000 | 260,000 |
| | Recoverable Costs Allocated to Demand - Prod-Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Recoverable Costs Allocated to Demand - A&G | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | Retail Energy Jurisdictional Factor | 0.97955 | 0.97713 | 0.95072 | 0.97138 | 0.97055 | 0.96353 | 0.95034 | 0.95576 | 0.96452 | 0.96282 | 0.97472 | 0.96865 | |
| 6 | Retail Transmission Demand Jurisdictional Factor | 0.71994 | 0.71994 | 0.71994 | 0.71994 | 0.71994 | 0.71994 | 0.71994 | 0.71994 | 0.71994 | 0.71994 | 0.71994 | 0.71994 | |
| | Retail Distribution Demand Jurisdictional Factor | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | |
| | Retail Production Demand Jurisdictional Factor - Base | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | |
| | Retail Production Demand Jurisdictional Factor - Intm | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | |
| | Retail Production Demand Jurisdictional Factor - Peaking | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | |
| | Retail Production Demand Jurisdictional Factor - A&G | 0.95415 | 0.95415 | 0.95415 | 0.95415 | 0.95415 | 0.95415 | 0.95415 | 0.95415 | 0.95415 | 0.95415 | 0.95415 | 0.95415 | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | 557,338 | 632,195 | 835,805 | 607,336 | 787,940 | 686,648 | 706,293 | 739,627 | 725,612 | 694,189 | 391,644 | 487,026 | 7,851,653 |
| 8 | Jurisdictional Demand Recoverable Costs - Transm (B) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Jurisdictional Demand Recoverable Costs - Distrib (B) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Jurisdictional Demand Recoverable Costs - Prod-Base (B) | 4,984 | 4,984 | 4,984 | 23,557 | 4,984 | 4,984 | 4,984 | 4,984 | 4,984 | 9,627 | 9,627 | 4,984 | 87,667 |
| | Jurisdictional Demand Recoverable Costs - Prod-Intm (B) | 0 | 18,400 | 18,400 | 18,401 | 18,400 | 18,400 | 18,401 | 0 | 8,832 | 75,073 | 17,664 | 17,664 | 229,635 |
| | Jurisdictional Demand Recoverable Costs - Prod-Peaking (B) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Jurisdictional Demand Recoverable Costs - A&G (B) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8) | $562,322 | $655,579 | $859,189 | $649,294 | $811,324 | $710,032 | $729,678 | $744,611 | $739,428 | $778,889 | $418,935 | $509,674 | $8,168,955 |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2022 - December 2022**

**Capital Investment Projects-Recoverable Costs**
**(in Dollars)**

Form 42-3P

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)


| Line | Description | Estimated Jan-22 | Estimated Feb-22 | Estimated Mar-22 | Estimated Apr-22 | Estimated May-22 | Estimated Jun-22 | Estimated Jul-22 | Estimated Aug-22 | Estimated Sep-22 | Estimated Oct-22 | Estimated Nov-22 | Estimated Dec-22 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investment Projects - System (A) | | | | | | | | | | | | | |
| 3.1 | Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.1 | Above Ground Tank Secondary Containment - Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4.2 | Above Ground Tank Secondary Containment - Base | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4.3 | Above Ground Tank Secondary Containment - Intm | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | SO2/NOX Emissions Allowances - Energy | 20,281 | 20,276 | 20,268 | 20,259 | 20,251 | 20,243 | 20,235 | 20,226 | 20,217 | 20,209 | 20,203 | 20,199 | 242,867 |
| 6 | Phase II Cooling Water Intake 316(b) - Base | 119,356 | 119,102 | 118,847 | 118,593 | 118,339 | 118,085 | 117,831 | 117,577 | 117,322 | 117,069 | 116,815 | 116,560 | 1,415,496 |
| 6.1 | Phase II Cooling Water Intake 316(b) - Base - Bartow | 281 | 842 | 1,404 | 1,965 | 2,527 | 3,089 | 3,651 | 4,212 | 4,774 | 5,335 | 5,897 | 6,458 | 40,435 |
| 6.2 | Phase II Cooling Water Intake 316(b) - Intermediate - Anclote | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.1 | CAIR/CAMR Anclote- Intm | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.2 | CAIR/CAMR - Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7.4 | CAIR/CAMR Crystal River AFUDC - Energy | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 231,778 |
| 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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10.1 | Underground Storage Tanks - Base | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10.2 | Underground Storage Tanks - Intm | 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 |
| 11.1 | Crystal River Thermal Discharge Compliance Project - Base (Post 2012) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11.1 | Crystal River Thermal Discharge Compliance Project - Base (2012) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15.1 | Effluent Limitation Guidelines CRN (ELG) - Base | 26,770 | 26,700 | 26,632 | 26,564 | 26,496 | 26,427 | 26,359 | 26,291 | 26,222 | 26,153 | 26,085 | 26,016 | 316,715 |
| 16 | National Pollutant Discharge Elimination System (NPDES) - Intm | 105,452 | 105,232 | 105,013 | 104,794 | 104,575 | 104,356 | 104,137 | 103,917 | 103,698 | 103,479 | 103,260 | 103,042 | 1,250,955 |
| 17 | Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy | 35,534 | 35,437 | 35,341 | 35,244 | 35,147 | 35,050 | 34,953 | 34,857 | 34,760 | 34,663 | 34,567 | 34,470 | 420,023 |
| 17.1 | Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17.2 | Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | Coal Combustion Residual (CCR) Rule - Base | 44,862 | 44,749 | 44,636 | 44,523 | 44,409 | 44,296 | 44,184 | 44,070 | 43,957 | 43,844 | 43,731 | 43,617 | 530,878 |
| 2 | Total Investment Projects - Recoverable Costs | $371,851 | $371,653 | $371,456 | $371,257 | $371,059 | $370,861 | $370,665 | $370,465 | $370,265 | $370,067 | $369,873 | $369,677 | $4,449,147 |
| 3 | Recoverable Costs Allocated to Energy | 75,130 | 75,028 | 74,924 | 74,818 | 74,713 | 74,608 | 74,503 | 74,398 | 74,292 | 74,187 | 74,085 | 73,984 | 894,668 |
| | Recoverable Costs Allocated to Distribution Demand | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | Recoverable Costs Allocated to Demand - Production - Base | 191,269 | 191,393 | 191,519 | 191,645 | 191,771 | 191,897 | 192,025 | 192,150 | 192,275 | 192,401 | 192,528 | 192,651 | 2,303,524 |
| | Recoverable Costs Allocated to Demand - Production - Intermediate | 105,452 | 105,232 | 105,013 | 104,794 | 104,575 | 104,356 | 104,137 | 103,917 | 103,698 | 103,479 | 103,260 | 103,042 | 1,250,955 |
| | Recoverable Costs Allocated to Demand - Production - Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | Retail Energy Jurisdictional Factor | 0.97955 | 0.97713 | 0.95072 | 0.97138 | 0.97055 | 0.96353 | 0.95034 | 0.95576 | 0.96452 | 0.96282 | 0.97472 | 0.96865 | |
| | Retail Distribution Demand Jurisdictional Factor | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | 1.00000 | |
| 6 | Retail Demand Jurisdictional Factor - Production - Base | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | |
| | Retail Demand Jurisdictional Factor - Production - Intermediate | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | |
| | Retail Demand Jurisdictional Factor - Production - Peaking | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | 0.90678 | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | 73,593 | 73,312 | 71,232 | 72,676 | 72,513 | 71,887 | 70,803 | 71,106 | 71,656 | 71,428 | 72,212 | 71,664 | 864,083 |
| | Jurisdictional Demand Recoverable Costs - Distribution (B) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Jurisdictional Demand Recoverable Costs - Production - Base (C) | 177,622 | 177,737 | 177,854 | 177,971 | 178,088 | 178,205 | 178,324 | 178,440 | 178,556 | 178,673 | 178,791 | 178,905 | 2,139,168 |
| | Jurisdictional Demand Recoverable Costs - Production - Intermediate (C) | 93,136 | 92,942 | 92,749 | 92,555 | 92,362 | 92,168 | 91,975 | 91,781 | 91,587 | 91,394 | 91,200 | 91,008 | 1,104,856 |
| | Jurisdictional Demand Recoverable Costs - Production - Peaking (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8) | $344,352 | $343,991 | $341,834 | $343,203 | $342,962 | $342,260 | $341,102 | $341,327 | $341,799 | $341,495 | $342,203 | $341,577 | $4,108,106 |

Notes:

(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9; Form 42-4P, Line 5 for Projects 5 - Emission Allowances and Project 7. 4 - Reagents.
(B) Line 3 x Line 5
(C) Line 4 x Line 6

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2022 - December 2022**

**SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)**
**(in Dollars)**

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)
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| Line | Description | | Beginning of Period Amount | Estimated Jan-22 | Estimated Feb-22 | Estimated Mar-22 | Estimated Apr-22 | Estimated May-22 | Estimated Jun-22 | Estimated Jul-22 | Estimated Aug-22 | Estimated Sep-22 | Estimated Oct-22 | Estimated Nov-22 | Estimated Dec-22 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0158150 $SO_2$ Emission Allowance Inventory | | $3,209,227 | $3,208,240 | $3,207,273 | $3,205,720 | $3,204,538 | $3,203,249 | $3,201,960 | $3,200,527 | $3,199,177 | $3,197,915 | $3,196,604 | $3,195,941 | $3,195,093 | $3,195,093 |
| | b. 0254020 Auctioned $SO_2$ Allowance | | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. 0158170 NOx Emission Allowance Inventory | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Other (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | Total Working Capital | | $3,209,227 | $3,208,240 | $3,207,273 | $3,205,720 | $3,204,538 | $3,203,249 | $3,201,960 | $3,200,527 | $3,199,177 | $3,197,915 | $3,196,604 | $3,195,941 | $3,195,093 | $3,195,093 |
| 3 | Average Net Investment | | | $3,208,734 | $3,207,757 | $3,206,497 | $3,205,129 | $3,203,893 | $3,202,605 | $3,201,244 | $3,199,852 | $3,198,546 | $3,197,259 | $3,196,272 | $3,195,517 | |
| 4 | Return on Average Net Working Capital Balance (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 1.70% | | 4,532 | 4,531 | 4,529 | 4,527 | 4,525 | 4,524 | 4,522 | 4,520 | 4,518 | 4,516 | 4,515 | 4,514 | 54,273 |
| | b. Equity Component Grossed Up For Taxes | 5.89% | | 15,749 | 15,745 | 15,739 | 15,732 | 15,726 | 15,719 | 15,713 | 15,706 | 15,699 | 15,693 | 15,688 | 15,685 | 188,594 |
| 5 | Total Return Component (C) | | | $20,281 | $20,276 | $20,268 | $20,259 | $20,251 | $20,243 | $20,235 | $20,226 | $20,217 | $20,209 | $20,203 | $20,199 | 242,867 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0509030 $SO_2$ Allowance Expense | | | $986 | $967 | $1,553 | $1,182 | $1,289 | $1,289 | $1,433 | $1,350 | $1,262 | $1,312 | $662 | $848 | 14,134 |
| | b. 0407426 Amortization Expense | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. 0 509212 NOx Allowance Expense | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Net Expense (D) | | | 986 | 967 | 1,553 | 1,182 | 1,289 | 1,289 | 1,433 | 1,350 | 1,262 | 1,312 | 662 | 848 | 14,134 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | | $21,267 | $21,243 | $21,821 | $21,441 | $21,540 | $21,532 | $21,668 | $21,576 | $21,479 | $21,521 | $20,865 | $21,047 | 257,001 |
| | a. Recoverable costs allocated to Energy | | | $21,267 | $21,243 | $21,821 | $21,441 | $21,540 | $21,532 | $21,668 | $21,576 | $21,479 | $21,521 | $20,865 | $21,047 | 257,001 |
| | b. Recoverable costs allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 9 | Energy Jurisdictional Factor | | | 0.97955 | 0.97713 | 0.95072 | 0.97138 | 0.97055 | 0.96353 | 0.95034 | 0.95576 | 0.96452 | 0.96282 | 0.97472 | 0.96865 | |
| 10 | Demand Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Retail Energy-Related Recoverable Costs (E) | | | $20,832 | $20,757 | $20,746 | $20,828 | $20,905 | $20,746 | $20,592 | $20,621 | $20,717 | $20,721 | $20,338 | $20,387 | 248,191 |
| 12 | Retail Demand-Related Recoverable Costs (F) | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 13 | Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | | $ 20,832 | $ 20,757 | $ 20,746 | $ 20,828 | $ 20,905 | $ 20,746 | $ 20,592 | $ 20,621 | $ 20,717 | $ 20,721 | $ 20,338 | $ 20,387 | $ 248,191 |

Notes:

(A) N/A
(B) Line 3 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 5 is reported on Capital Schedule
(D) Line 7 is reported on O&M Schedule
(E) Line 8a x Line 9
(F) Line 8b x Line 10

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Projection Amount**
**January 2022 - December 2022**

**Return on Capital Investments, Depreciation and Taxes**
**For Project: Phase II Cooling Water Intake 316(b) - Base (Project 6)**
**(in Dollars)**

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)
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| Line | Description | | Beginning of Period Amount | Estimated Jan-22 | Estimated Feb-22 | Estimated Mar-22 | Estimated Apr-22 | Estimated May-22 | Estimated Jun-22 | Estimated Jul-22 | Estimated Aug-22 | Estimated Sep-22 | Estimated Oct-22 | Estimated Nov-22 | Estimated Dec-22 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $12,505,047 | 12,505,047 | 12,505,047 | 12,505,047 | 12,505,047 | 12,505,047 | 12,505,047 | 12,505,047 | 12,505,047 | 12,505,047 | 12,505,047 | 12,505,047 | 12,505,047 | |
| 3 | Less: Accumulated Depreciation | | (46,273) | (86,478) | (126,683) | (166,888) | (207,093) | (247,298) | (287,503) | (327,708) | (367,913) | (408,118) | (448,323) | (488,528) | (528,733) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $12,458,774 | $12,418,569 | $12,378,364 | $12,338,159 | $12,297,954 | $12,257,749 | $12,217,544 | $12,177,339 | $12,137,134 | $12,096,929 | $12,056,724 | $12,016,519 | $11,976,314 | |
| 6 | Average Net Investment | | | $12,438,671 | $12,398,466 | $12,358,261 | $12,318,056 | $12,277,851 | $12,237,646 | $12,197,441 | $12,157,236 | $12,117,031 | $12,076,826 | $12,036,621 | $11,996,416 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 1.70% | | 17,570 | 17,513 | 17,456 | 17,399 | 17,342 | 17,286 | 17,229 | 17,172 | 17,115 | 17,059 | 17,002 | 16,945 | 207,088 |
| | b. Equity Component Grossed Up For Taxes | 5.89% | | 61,053 | 60,856 | 60,658 | 60,461 | 60,264 | 60,066 | 59,869 | 59,672 | 59,474 | 59,277 | 59,080 | 58,882 | 719,612 |
| | c. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.8582% | | 40,205 | 40,205 | 40,205 | 40,205 | 40,205 | 40,205 | 40,205 | 40,205 | 40,205 | 40,205 | 40,205 | 40,205 | 482,460 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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) | 0.000507 | | 528 | 528 | 528 | 528 | 528 | 528 | 528 | 528 | 528 | 528 | 528 | 528 | 6,336 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $119,356 | $119,102 | $118,847 | $118,593 | $118,339 | $118,085 | $117,831 | $117,577 | $117,322 | $117,069 | $116,815 | $116,560 | 1,415,496 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 119,356 | 119,102 | 118,847 | 118,593 | 118,339 | 118,085 | 117,831 | 117,577 | 117,322 | 117,069 | 116,815 | 116,560 | 1,415,496 |
| 10 | Energy Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor | | | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | |
| 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) | | | 110,840 | 110,604 | 110,367 | 110,131 | 109,896 | 109,660 | 109,424 | 109,188 | 108,951 | 108,716 | 108,480 | 108,243 | 1,314,500 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $110,840 | $110,604 | $110,367 | $110,131 | $109,896 | $109,660 | $109,424 | $109,188 | $108,951 | $108,716 | $108,480 | $108,243 | $1,314,500 |

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 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 2022 - December 2022**

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: Phase II Cooling Water Intake 316(b) - Base - Bartow (Project 6.1)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-22 | Estimated Feb-22 | Estimated Mar-22 | Estimated Apr-22 | Estimated May-22 | Estimated Jun-22 | Estimated Jul-22 | Estimated Aug-22 | Estimated Sep-22 | Estimated Oct-22 | Estimated Nov-22 | Estimated Dec-22 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $88,848 | $88,848 | $88,848 | $88,848 | $88,848 | $88,848 | $88,848 | $88,848 | $88,848 | $88,848 | $88,848 | $88,848 | $1,066,178 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | 88,848 | 177,696 | 266,545 | 355,393 | 444,241 | 533,089 | 621,937 | 710,785 | 799,634 | 888,482 | 977,330 | 1,066,178 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $0 | $88,848 | $177,696 | $266,545 | $355,393 | $444,241 | $533,089 | $621,937 | $710,785 | $799,634 | $888,482 | $977,330 | $1,066,178 | |
| 6 | Average Net Investment | | | $44,424 | $133,272 | $222,120 | $310,969 | $399,817 | $488,665 | $577,513 | $666,361 | $755,209 | $844,058 | $932,906 | $1,021,754 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 1.70% | | 63 | 188 | 314 | 439 | 565 | 690 | 816 | 941 | 1,067 | 1,192 | 1,318 | 1,443 | 9,036 |
| | b. Equity Component Grossed Up For Taxes | 5.89% | | 218 | 654 | 1,090 | 1,526 | 1,962 | 2,399 | 2,835 | 3,271 | 3,707 | 4,143 | 4,579 | 5,015 | 31,399 |
| | c. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.8582% | | 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) | 0.000507 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $281 | $842 | $1,404 | $1,965 | $2,527 | $3,089 | $3,651 | $4,212 | $4,774 | $5,335 | $5,897 | $6,458 | 40,435 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 281 | 842 | 1,404 | 1,965 | 2,527 | 3,089 | 3,651 | 4,212 | 4,774 | 5,335 | 5,897 | 6,458 | 40,435 |
| 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) | | | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | |
| 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) | | | 261 | 782 | 1,304 | 1,825 | 2,347 | 2,869 | 3,391 | 3,911 | 4,433 | 4,954 | 5,476 | 5,997 | 37,550 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $261 | $782 | $1,304 | $1,825 | $2,347 | $2,869 | $3,391 | $3,911 | $4,433 | $4,954 | $5,476 | $5,997 | $37,550 |

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 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 2022 - December 2022**

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: Phase II Cooling Water Intake 316(b) - Intermediate - Anclote (Project 6.2)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-22 | Estimated Feb-22 | Estimated Mar-22 | Estimated Apr-22 | Estimated May-22 | Estimated Jun-22 | Estimated Jul-22 | Estimated Aug-22 | Estimated Sep-22 | Estimated Oct-22 | Estimated Nov-22 | Estimated Dec-22 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3 | Less: Accumulated Depreciation | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 6 | Average Net Investment | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 1.70% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Equity Component Grossed Up For Taxes | 5.89% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 10.3694% | | 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) | 0.005960 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor - Production (Intermediate) | | | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13 | Retail Demand-Related Recoverable Costs (F) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 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 2022 - December 2022**

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-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-22 | Estimated Feb-22 | Estimated Mar-22 | Estimated Apr-22 | Estimated May-22 | Estimated Jun-22 | Estimated Jul-22 | Estimated Aug-22 | Estimated Sep-22 | Estimated Oct-22 | Estimated Nov-22 | Estimated Dec-22 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 0154401 Ammonia Inventory | | $1,343,285 | $1,343,285 | $1,343,285 | $1,343,285 | $1,343,285 | $1,343,285 | $1,343,285 | $1,343,285 | $1,343,285 | $1,343,285 | $1,343,285 | $1,343,285 | $1,343,285 | 1,343,285 |
| | b. 0154200 Limestone Inventory | | $1,712,468 | 1,712,468 | 1,712,468 | 1,712,468 | 1,712,468 | 1,712,468 | 1,712,468 | 1,712,468 | 1,712,468 | 1,712,468 | 1,712,468 | 1,712,468 | 1,712,468 | 1,712,468 |
| 2 | Total Working Capital | | $3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 |
| 3 | Average Net Investment | | | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | 3,055,753 | |
| 4 | Return on Average Net Working Capital Balance (A) | | | | | | | | | | | | | | | |
| | a. Debt Component | 1.70% | | 4,316 | 4,316 | 4,316 | 4,316 | 4,316 | 4,316 | 4,316 | 4,316 | 4,316 | 4,316 | 4,316 | 4,316 | $51,795 |
| | b. Equity Component Grossed Up For Taxes | 5.89% | | 14,999 | 14,999 | 14,999 | 14,999 | 14,999 | 14,999 | 14,999 | 14,999 | 14,999 | 14,999 | 14,999 | 14,999 | 179,983 |
| 5 | Total Return Component (B) | | | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 19,315 | 231,778 |
| 6 | | | | | | | | | | | | | | | | |
| | a. 0502010 Ammonia Expense | | | 271,900 | 277,100 | 389,800 | 306,700 | 379,100 | 352,900 | 370,700 | 385,800 | 371,300 | 351,900 | 182,600 | 225,900 | 3,865,700 |
| | b. 0502040 Limestone Expense | | | 413,657 | 405,531 | 650,922 | 495,542 | 539,958 | 539,805 | 600,169 | 565,083 | 528,289 | 550,643 | 277,661 | 355,773 | 5,923,033 |
| | c. 0502050 Dibasic Acid Expense | | | 2,600 | 2,800 | 3,800 | 3,000 | 3,700 | 3,400 | 3,600 | 3,800 | 3,700 | 3,400 | 1,800 | 2,200 | 37,800 |
| | d. 0502070 Gypsum Disposal/Sale | | | (404,655) | (396,794) | (637,035) | (485,079) | (528,674) | (528,642) | (587,890) | (553,653) | (517,731) | (538,134) | (271,606) | (347,917) | (5,797,810) |
| | e. 0502040 Hydrated Lime Expense | | | 248,000 | 252,900 | 356,100 | 280,200 | 346,300 | 322,400 | 338,700 | 352,500 | 339,200 | 321,600 | 167,100 | 206,500 | 3,531,500 |
| | f. 0502300 Caustic Expense | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Net Expense (C) | | | 531,503 | 541,537 | 763,587 | 600,363 | 740,384 | 689,863 | 725,279 | 753,530 | 724,758 | 689,409 | 357,556 | 442,456 | 7,560,224 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | | $550,817 | $560,852 | $782,902 | $619,678 | $759,699 | $709,177 | $744,593 | $772,844 | $744,073 | $708,724 | $376,870 | $461,771 | $7,792,002 |
| | a. Recoverable Costs Allocated to Energy | | | 550,817 | 560,852 | 782,902 | 619,678 | 759,699 | 709,177 | 744,593 | 772,844 | 744,073 | 708,724 | 376,870 | 461,771 | 7,792,002 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | Energy Jurisdictional Factor | | | 0.97955 | 0.97713 | 0.95072 | 0.97138 | 0.97055 | 0.96353 | 0.95034 | 0.95576 | 0.96452 | 0.96282 | 0.97472 | 0.96865 | |
| 10 | Demand Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Retail Energy-Related Recoverable Costs (D) | | | 539,552 | 548,027 | 744,323 | 601,942 | 737,325 | 683,315 | 707,620 | 738,651 | 717,671 | 682,371 | 367,341 | 447,293 | 7,515,431 |
| 12 | Retail Demand-Related Recoverable Costs (E) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | | $ 539,552 | $ 548,027 | $ 744,323 | $ 601,942 | $ 737,325 | $ 683,315 | $ 707,620 | $ 738,651 | $ 717,671 | $ 682,371 | $ 367,341 | $ 447,293 | $ 7,515,431 |

Notes:

(A) Line 3 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(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 2022 - December 2022**

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: Effluent Limitation Guidelines CRN - Base (Project 15.1)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-22 | Estimated Feb-22 | Estimated Mar-22 | Estimated Apr-22 | Estimated May-22 | Estimated Jun-22 | Estimated Jul-22 | Estimated Aug-22 | Estimated Sep-22 | Estimated Oct-22 | Estimated Nov-22 | Estimated Dec-22 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $2,612,979 | 2,612,979 | 2,612,979 | 2,612,979 | 2,612,979 | 2,612,979 | 2,612,979 | 2,612,979 | 2,612,979 | 2,612,979 | 2,612,979 | 2,612,979 | 2,612,979 | |
| 3 | Less: Accumulated Depreciation | | (102,323) | (113,147) | (123,971) | (134,795) | (145,619) | (156,443) | (167,267) | (178,091) | (188,915) | (199,739) | (210,563) | (221,387) | (232,211) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $2,510,656 | $2,499,832 | $2,489,008 | $2,478,184 | $2,467,360 | $2,456,536 | $2,445,712 | $2,434,888 | $2,424,064 | $2,413,240 | $2,402,416 | $2,391,592 | $2,380,768 | |
| 6 | Average Net Investment | | | $2,505,244 | $2,494,420 | $2,483,596 | $2,472,772 | $2,461,948 | $2,451,124 | $2,440,300 | $2,429,476 | $2,418,652 | $2,407,828 | $2,397,004 | $2,386,180 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 1.70% | | 3,539 | 3,523 | 3,508 | 3,493 | 3,478 | 3,462 | 3,447 | 3,432 | 3,416 | 3,401 | 3,386 | 3,370 | 41,455 |
| | b. Equity Component Grossed Up For Taxes | 5.89% | | 12,297 | 12,243 | 12,190 | 12,137 | 12,084 | 12,031 | 11,978 | 11,925 | 11,872 | 11,818 | 11,765 | 11,712 | 144,052 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 4.9707% | | 10,824 | 10,824 | 10,824 | 10,824 | 10,824 | 10,824 | 10,824 | 10,824 | 10,824 | 10,824 | 10,824 | 10,824 | 129,888 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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) | 0.000507 | | 110 | 110 | 110 | 110 | 110 | 110 | 110 | 110 | 110 | 110 | 110 | 110 | 1,320 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $26,770 | $26,700 | $26,632 | $26,564 | $26,496 | $26,427 | $26,359 | $26,291 | $26,222 | $26,153 | $26,085 | $26,016 | 316,715 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 26,770 | 26,700 | 26,632 | 26,564 | 26,496 | 26,427 | 26,359 | 26,291 | 26,222 | 26,153 | 26,085 | 26,016 | 316,715 |
| 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) | | | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | |
| 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) | | | 24,860 | 24,795 | 24,732 | 24,669 | 24,606 | 24,541 | 24,478 | 24,415 | 24,351 | 24,287 | 24,224 | 24,160 | 294,117 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $24,860 | $24,795 | $24,732 | $24,669 | $24,606 | $24,541 | $24,478 | $24,415 | $24,351 | $24,287 | $24,224 | $24,160 | $294,117 |

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 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 2022 - December 2022**

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-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-22 | Estimated Feb-22 | Estimated Mar-22 | Estimated Apr-22 | Estimated May-22 | Estimated Jun-22 | Estimated Jul-22 | Estimated Aug-22 | Estimated Sep-22 | Estimated Oct-22 | Estimated Nov-22 | Estimated Dec-22 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $12,841,870 | 12,841,870 | 12,841,870 | 12,841,870 | 12,841,870 | 12,841,870 | 12,841,870 | 12,841,870 | 12,841,870 | 12,841,870 | 12,841,870 | 12,841,870 | 12,841,870 | |
| 3 | Less: Accumulated Depreciation | | (3,000,702) | (3,035,369) | (3,070,036) | (3,104,703) | (3,139,370) | (3,174,037) | (3,208,704) | (3,243,371) | (3,278,038) | (3,312,705) | (3,347,372) | (3,382,039) | (3,416,706) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $9,841,168 | $9,806,501 | $9,771,834 | $9,737,167 | $9,702,500 | $9,667,833 | $9,633,166 | $9,598,499 | $9,563,832 | $9,529,165 | $9,494,498 | $9,459,831 | $9,425,164 | |
| 6 | Average Net Investment | | | $9,823,835 | $9,789,168 | $9,754,501 | $9,719,834 | $9,685,167 | $9,650,500 | $9,615,833 | $9,581,166 | $9,546,499 | $9,511,832 | $9,477,165 | $9,442,498 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 1.70% | | 13,876 | 13,827 | 13,778 | 13,729 | 13,680 | 13,631 | 13,582 | 13,533 | 13,484 | 13,435 | 13,386 | 13,338 | 163,279 |
| | b. Equity Component Grossed Up For Taxes | 5.89% | | 48,219 | 48,048 | 47,878 | 47,708 | 47,538 | 47,368 | 47,198 | 47,027 | 46,857 | 46,687 | 46,517 | 46,347 | 567,392 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 3.239% | | 34,667 | 34,667 | 34,667 | 34,667 | 34,667 | 34,667 | 34,667 | 34,667 | 34,667 | 34,667 | 34,667 | 34,667 | 416,004 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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) | 0.008120 | | 8,690 | 8,690 | 8,690 | 8,690 | 8,690 | 8,690 | 8,690 | 8,690 | 8,690 | 8,690 | 8,690 | 8,690 | 104,280 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $105,452 | $105,232 | $105,013 | $104,794 | $104,575 | $104,356 | $104,137 | $103,917 | $103,698 | $103,479 | $103,260 | $103,042 | 1,250,955 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | $105,452 | $105,232 | $105,013 | $104,794 | $104,575 | $104,356 | $104,137 | $103,917 | $103,698 | $103,479 | $103,260 | $103,042 | 1,250,955 |
| 10 | Energy Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor - Production (Intermediate) | | | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | 0.88321 | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13 | Retail Demand-Related Recoverable Costs (F) | | | 93,136 | 92,942 | 92,749 | 92,555 | 92,362 | 92,168 | 91,975 | 91,781 | 91,587 | 91,394 | 91,200 | 91,008 | 1,104,856 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $93,136 | $92,942 | $92,749 | $92,555 | $92,362 | $92,168 | $91,975 | $91,781 | $91,587 | $91,394 | $91,200 | $91,008 | $1,104,856 |

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 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 2022 - December 2022**

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-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-22 | Estimated Feb-22 | Estimated Mar-22 | Estimated Apr-22 | Estimated May-22 | Estimated Jun-22 | Estimated Jul-22 | Estimated Aug-22 | Estimated Sep-22 | Estimated Oct-22 | Estimated Nov-22 | Estimated Dec-22 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base | | $3,690,187 | 3,690,187 | 3,690,187 | 3,690,187 | 3,690,187 | 3,690,187 | 3,690,187 | 3,690,187 | 3,690,187 | 3,690,187 | 3,690,187 | 3,690,187 | 3,690,187 | |
| 3 | Less: Accumulated Depreciation | | (503,933) | (519,219) | (534,505) | (549,791) | (565,077) | (580,363) | (595,649) | (610,935) | (626,221) | (641,507) | (656,793) | (672,079) | (687,365) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $3,186,254 | $3,170,968 | $3,155,682 | $3,140,396 | $3,125,110 | $3,109,824 | $3,094,538 | $3,079,252 | $3,063,966 | $3,048,680 | $3,033,394 | $3,018,108 | $3,002,822 | |
| 6 | Average Net Investment | | | $3,178,611 | $3,163,325 | $3,148,039 | $3,132,753 | $3,117,467 | $3,102,181 | $3,086,895 | $3,071,609 | $3,056,323 | $3,041,037 | $3,025,751 | $3,010,465 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 1.70% | | 4,490 | 4,468 | 4,447 | 4,425 | 4,403 | 4,382 | 4,360 | 4,339 | 4,317 | 4,295 | 4,274 | 4,252 | 52,452 |
| | b. Equity Component Grossed Up For Taxes | 5.89% | | 15,602 | 15,527 | 15,452 | 15,377 | 15,302 | 15,226 | 15,151 | 15,076 | 15,001 | 14,926 | 14,851 | 14,776 | 182,267 |
| | c. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 4.9707% | | 15,286 | 15,286 | 15,286 | 15,286 | 15,286 | 15,286 | 15,286 | 15,286 | 15,286 | 15,286 | 15,286 | 15,286 | 183,432 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/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) | 0.000507 | | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 1,872 |
| | e. Other | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $35,534 | $35,437 | $35,341 | $35,244 | $35,147 | $35,050 | $34,953 | $34,857 | $34,760 | $34,663 | $34,567 | $34,470 | 420,023 |
| | a. Recoverable Costs Allocated to Energy | | | 35,534 | 35,437 | 35,341 | 35,244 | 35,147 | 35,050 | 34,953 | 34,857 | 34,760 | 34,663 | 34,567 | 34,470 | 420,023 |
| | b. Recoverable Costs Allocated to Demand | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| 10 | Energy Jurisdictional Factor | | | 0.97955 | 0.97713 | 0.95072 | 0.97138 | 0.97055 | 0.96353 | 0.95034 | 0.95576 | 0.96452 | 0.96282 | 0.97472 | 0.96865 | |
| 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) | | | $34,807 | $34,627 | $33,600 | $34,235 | $34,112 | $33,772 | $33,217 | $33,315 | $33,527 | $33,374 | $33,693 | $33,389 | $405,668 |
| 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) | | | $34,807 | $34,627 | $33,600 | $34,235 | $34,112 | $33,772 | $33,217 | $33,315 | $33,527 | $33,374 | $33,693 | $33,389 | $405,668 |

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 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 2022 - December 2022**

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)
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**Return on Capital Investments, Depreciation and Taxes**
**For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Base (Project 18)**
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Estimated Jan-22 | Estimated Feb-22 | Estimated Mar-22 | Estimated Apr-22 | Estimated May-22 | Estimated Jun-22 | Estimated Jul-22 | Estimated Aug-22 | Estimated Sep-22 | Estimated Oct-22 | Estimated Nov-22 | Estimated Dec-22 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 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 | | $4,320,358 | 4,320,358 | 4,320,358 | 4,320,358 | 4,320,358 | 4,320,358 | 4,320,358 | 4,320,358 | 4,320,358 | 4,320,358 | 4,320,358 | 4,320,358 | 4,320,358 | |
| 3 | Less: Accumulated Depreciation (A) | | ($73,985) | (91,881) | (109,777) | (127,673) | (145,569) | (163,465) | (181,361) | (199,257) | (217,153) | (235,049) | (252,945) | (270,841) | (288,737) | |
| 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) | | $4,246,373 | $4,228,477 | $4,210,581 | $4,192,685 | $4,174,789 | $4,156,893 | $4,138,997 | $4,121,101 | $4,103,205 | $4,085,309 | $4,067,413 | $4,049,517 | $4,031,621 | |
| 6 | Average Net Investment | | | $4,237,425 | $4,219,529 | $4,201,633 | $4,183,737 | $4,165,841 | $4,147,945 | $4,130,049 | $4,112,153 | $4,094,257 | $4,076,361 | $4,058,465 | $4,040,569 | |
| 7 | Return on Average Net Investment (B) | | | | | | | | | | | | | | | |
| | a. Debt Component | 1.70% | | 5,985 | 5,960 | 5,935 | 5,910 | 5,884 | 5,859 | 5,834 | 5,808 | 5,783 | 5,758 | 5,733 | 5,707 | 70,156 |
| | b. Equity Component Grossed Up For Taxes | 5.89% | | 20,799 | 20,711 | 20,623 | 20,535 | 20,447 | 20,359 | 20,272 | 20,184 | 20,096 | 20,008 | 19,920 | 19,832 | 243,786 |
| | c. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (C) | 4.9707% | | 17,896 | 17,896 | 17,896 | 17,896 | 17,896 | 17,896 | 17,896 | 17,896 | 17,896 | 17,896 | 17,896 | 17,896 | 214,752 |
| | 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) | 0.000507 | | 182 | 182 | 182 | 182 | 182 | 182 | 182 | 182 | 182 | 182 | 182 | 182 | 2,184 |
| | e. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | $44,862 | $44,749 | $44,636 | $44,523 | $44,409 | $44,296 | $44,184 | $44,070 | $43,957 | $43,844 | $43,731 | $43,617 | 530,878 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 44,862 | 44,749 | 44,636 | 44,523 | 44,409 | 44,296 | 44,184 | 44,070 | 43,957 | 43,844 | 43,731 | 43,617 | 530,878 |
| 10 | Energy Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor | | | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | 0.92865 | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13 | Retail Demand-Related Recoverable Costs (F) | | | 41,661 | 41,556 | 41,451 | 41,346 | 41,240 | 41,135 | 41,031 | 40,926 | 40,821 | 40,716 | 40,611 | 40,505 | 493,000 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $41,661 | $41,556 | $41,451 | $41,346 | $41,240 | $41,135 | $41,031 | $40,926 | $40,821 | $40,716 | $40,611 | $40,505 | $493,000 |

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

**Project Title:** **Substation Environmental Investigation, Remediation and Pollution Prevention**
**Project No. 1**

**Project Description:**
Chapter 376 Florida Statutes requires that any person discharging a prohibited pollutant shall undertake to contain, remove and abate the discharge to the satisfaction of the FDEP. Similarly, Chapter 403 Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For DEF to comply with these statutes, it is actively conducting remediation and pollution prevention activities at its substation sites to remove the existence of pollutant discharges. Activities also include development and implementation of best management and pollution prevention measures at these sites.

**Project Accomplishments:**
The remediation portion of the Substation Assessment and Remedial Action Plan has been completed for all of the 279 SARAP substation sites. The Amended Deed Restrictive Covenant ("DRC") for West Lake Wales Substation has been approved by FDEP. The proposed DRC for Central Florida Substation submitted for approval to FDEP in July 2020. Project is complete as of first quarter 2021.

**Project Fiscal Expenditures:**
2021 O&M expenditures for the substation system program (Projects 1 & 1a) are estimated to be $263. This program is now complete.

**Project Progress Summary:**
This project is complete as of 1st quarter 2021.

**Project Projections:**
No further charges are expected to hit this project in 2022.

**Project Title:** **Distribution System Environmental Investigation, Remediation and Pollution Prevention**
**Project No. 2**

**Project Description:**
Chapter 376 Florida Statutes requires that any person discharging a prohibited pollutant shall undertake to contain, remove and abate the discharge to the satisfaction of the FDEP. Similarly, Chapter 403 Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For DEF to comply with these statutes, it is actively conducting remediation and pollution prevention activities at its distribution sites to remove the existence of pollutant discharges. Activities also include development and implementation of best management and pollution prevention measures at these sites.

**Project Accomplishments:**
All TRIP sites source removals are completed. The Final TRIP has been completed and the NAM report submitted to FDEP 4-4-19.

**Project Fiscal Expenditures:**
No further charges are expected to hit this project in 2021.

**Project Progress Summary:**
This project is complete.

**Project Projections:**
No further charges are expected to hit this project in 2022.

**Project Title:** **Pipeline Integrity Management (PIM) - Bartow/Anclote Pipeline**
**Project No. 3**

**Project Description:**
The U.S. Department of Transportation (USDOT) Regulation 49 CFR Part 195, as amended effective 2/15/02, and the new regulation published at 67 Federal Register 2136 on 1/16/02, requires DEF to implement a PIM program. Prior to the 2/15/02 amendments, the USDOT's PIM regulations applied only to operators with 500 miles or more of hazardous liquid and carbon dioxide pipelines that could affect high consequence areas. The amendments which became effective on 2/15/02, extended the requirements for implementing integrity management to operators who have less than 500 miles of regulated pipelines. As such, DEF must maintain the integrity of pipeline systems in order to protect public safety and the environment, and comply with continual assessment and evaluation of pipeline systems integrity through inspection or testing, data integration and analysis, and follow up with remedial, preventative, and mitigative actions. DEF owns one hazardous liquid pipeline, Bartow/Anclote 14-inch hot oil pipeline, extending 33.3 miles from the Company's Bartow Plant north of St. Petersburg to the Anclote Plant in Holiday, that is subject to PIM regulations.

Effective 2/2010, amendments to 49 CFR 195 were finalized to improve opportunities to reduce risk through more effective control of pipelines. Compliance with these amendments will enhance pipeline safety by coupling strengthened control room management with improved controller training and fatigue management. On 6/16/11, the USDOT published in the Federal Register (V0l. 76, 35130-35136), a final rule effective 8/15/11, that expedites the program implementation deadlines in the Control Room Management/Human Factors regulations in order to realize the safety benefits sooner than established in the original rule. This final rule amends the program implementation deadlines for different procedures to no later than 10/21/11 and 8/1/12.

**Project Accomplishments:**
Since the Bartow Anclote Pipeline (BAP) contained a small quantity of #6 fuel oil, the PIM program under 49CFR195 continues to be maintained. Third party projects by Florida Department of Transportation (FDOT), Florida Gas Transmission, Pinellas County, The City of Pinellas Park, and others have been evaluated for their risk to BAP integrity. Risk mitigation measures have been completed per 49CFR195.450. The BAP Risk Analysis has been updated. The Annual Report and National Pipeline Mapping System (NPMS) annual review have been completed. Reviews and evaluations are also being completed for Advisory Bulletins 11-04, 13-02, 15-01, and 15-02, relating to flooding and hurricanes. BAP personnel have participated in US Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA), utility owners groups, damage prevention groups, and FDOT workshops and training. Pipeline accidents and PHMSA enforcement actions have been reviewed for conditions that are applicable to the BAP and appropriate changes to BAP practices and procedures have been implemented. Pipeline records are being organized and stored with the conversion to electronic storage now essentially complete.

In 2016, pipeline ownership was transferred from the Fossil Hydro Operations group to Plant Retirement and Demolition, in preparation for pipeline retirement that is expected to occur in 2016. Once retired, the pipeline will be cleaned to remove any remaining oil. Once cleaned, the requirements described above in the PIM program will no longer be required. Cleaning is expected to occur in 2016, with any required demolition activities in 2017. As of the end of 2016, three of the four sub-projects were retired and approved to be amortized over three years - Project 3.1b Pipeline Leak Detection, Project 3.1c Pipeline Controls Upgrade, and Project 3.1d Control Room Management.

The final sub-project 3.1a - Alderman Road Fence was retired June 2017 and approved as a regulatory asset. This was amortized over 26 months, and all four parts of this project are fully amortized as of September 2019.

**Project Fiscal Expenditures:**
No capital or O&M expenditures are estimated for 2021.

**Project Progress Summary:**
Projects 3.1b (Pipeline leak Detection), 3.1c (Pipeline Controls Upgrade), and 3.1d (Control Room Management) were retired August 2016. Project 3.1a (Alderman Road Fence) retired June 2017. All are fully amortized as of September 2019.

**Project Projections:**
No capital or O&M expenditures are estimated for 2022.

**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 2021.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications. Project 4.1a (Turner CTs) retired in March 2016.

Project was moved to base rates as of January 2022, per Order No. PSC-2021-0202-AS-EI.

**Project Projections:**
No new project expenditures are expected in 2022.

**Project Title:** **$SO_2$ and NOx Emissions Allowances**
**Project No. 5**

**Project Description:**
In accordance with the Acid Rain Program in Title IV of the Clean Air Act, CFR 40 Part 73 and Part 76, Florida Administrative Code Rule 62-214 and the Clean Air Interstate Rule (CAIR), DEF manages sulfur dioxide ($SO_2$) and nitrogen oxide (NOx) allowance inventory to offset emissions. On 7/6/11, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to replace the CAIR. The CSAPR significantly alters $SO_2$ and NOx allowance programs. Under the CAIR, Florida has to comply with annual $SO_2$ and NOx emission requirements, and seasonal NOx emission requirements. Under the CSAPR, Florida is no longer required to comply with annual emissions requirements, only ozone seasonal limits. On 8/8/11, the final CSAPR was published in the Federal Register. The CSAPR sets state-level annual and seasonal $SO_2$ and NOx emission allowance requirements effective 1/1/12.

On 8/21/12, the D.C. Circuit Court vacated the CSAPR. It also directed the EPA to continue administering the CAIR which requires additional reductions in $SO_2$ and NOx emissions beginning in 2015. On 4/29/14, the U.S. Supreme Court reversed the D.C. Circuit Court decision finding that with CSAPR the EPA reasonably interpreted the good neighbor provision of the Clean Air Act. The case was then remanded to the D.C. Circuit Court for further proceedings, and the EPA requested the court lift the CSAPR stay and direct it to take effect on 1/1/15. On 10/23/14 the D.C. Circuit Court lifted the CSAPR stay. On 1/1/15, the CSAPR replaced the CAIR. The CSAPR took effect in Florida on 5/1/15. Consequently, CAIR NOx emission allowances have no value; however, SO2 emission allowances can continue to be used to comply with the Acid Rain Program. DEF treated its unused NOx costs as a regulatory asset amortizing it over 3 years, as approved by the Commission in Order No. PSC-2011-0553-FOF-EI. These are fully recovered as of December 2017.

**Project Accomplishments:**
Air quality compliance costs are administered by an authorized account representative who evaluates a variety of resources and options. Activities performed include purchases of SO2 and NOx emissions allowances as well as auctions and transfers of SO2 emissions allowances.

**Project Fiscal Expenditures:**
2021 O&M is forecasted to be $12k.

**Project Progress Summary:**
DEF continually evaluates the status of emission rules to maximize the cost effectiveness of its compliance strategy.

**Project Projections:**
2022 O&M expenditures are projected to be $14k.

**Project Title:** **Phase II Cooling Water Intake**
**Project No. 6**

**Project Description:**
Section 316(b) of the Federal Clean Water Act requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. 33 U.S.C. Section 1326. On 5/19/14, the EPA Administrator signed a final 316(b) rule to protect fish and aquatic life drawn into cooling systems at power plant and factories. The rule aims to minimize impingement (aquatic life pinned against cooling water intake structures) and entrainment (aquatic life drawn into cooling water systems). The regulation became effective on October 14, 2014, 60 days after publication in the Federal Register which was 8/15/14.

EPA's regulation implementing §316(b) of the Clean Water Act for existing facilities was published on August 15, 2014. The regulation aims to minimize adverse environmental impacts to fish and other aquatic organisms from the operation of cooling water intake structures. The regulation became effective October 14, 2014, 60 days after publication in the Federal Register. The regulation primarily applies to existing power generating facilities that commenced construction prior to or on January 17, 2002 and to new units at existing facilities that are built to increase the generating capacity of the facility.

According to the current 316(b) rule, required studies and information submittals will be due with the renewal of the NPDES permit application for permits that expire after July 18, 2018. Permittees with a current NPDES permit that expires before July 18, 2018 may request the FDEP establish an alternative schedule for submitting the required information. This rule is applicable to Anclote, Bartow, Suwannee, and Crystal River North stations.

**Project Accomplishments:**
DEF is currently evaluating the 316(b) rule to determine potential study requirements, operating and cost impacts to its generating stations. Site specific strategic plans, studies, and implementation plans are under development to ensure compliance with all applicable requirements of the rule.

**Project Fiscal Expenditures:**
2021 O&M expenditures are estimated to be $30k. 2021 Capital expenditures are estimated to be $2.2M.

**Project Progress Summary:**
Required 316(b) reports have been finalized and with the NPDES permit renewal applications to FDEP for review and approval. Anclote & Bartow permit applications have been filed with FDEP.

**Project Projections:**
2022 estimated O&M expenditures are $280k, and capital $1.1M.

**Project Title:** **Integrated Clean Air Compliance Plan - Clean Air Interstate Rule (CAIR)**
**Project Nos. (7.2, 7.3 & 7.4)**

**Project Description:**
The Clean Air Interstate Rule (CAIR), 40 CFR 24, 262, imposes significant restrictions on emissions of $SO_2$ and NOx from power plants in 28 eastern states, including Florida and the District of Columbia. The CAIR rule apportions region-wide $SO_2$ and NOx emission reduction requirements to the individual states, and further requires each affected state to revise its State Implementation Plans (SIPs) to include measures necessary to achieve its emission reduction budget within prescribed deadlines.

The Cross-State air pollution Rule (CSAPR) replaced CAIR on 1/1/15. Under the CSAPR, the State of Florida is no longer required to comply with annual emission requirements, only NOx ozone seasonal limits. The CSAPR requirements took effect in Florida on 5/1/15, the beginning of the ozone season. NOx emission allowances under CAIR have no value; however, DEF will continue to use its SO2 emission allowances to comply with the Acid Rain Program. (see Project No. 5 - SO2 and NOx Emission Allowances Project Sheet for more information).

The Florida Department of Environmental Protection ("FDEP") Conditions of Certification, dated August 1, 2012, require DEF to evaluate an alternative disposal method of FGD Blowdown wastewater based on results of groundwater monitoring near percolation ponds. DEF is installing a physical/chemical treatment system to treat FGD Blowdown wastewater with discharge to surface water or percolation ponds.

**Project Accomplishments:**
The FGD Wastewater treatment (WWT) system went in-service February 2019.

All projects except 7.4 CAIR/CAMR Crystal River - Energy (Reagents) have been moved to base rates as of January 2022, as approved in Order No. PSC-2021-0202-AS-EI.

**Project Fiscal Expenditures:**
For 2021, O&M expenditures for CAIR/CAMR – Peaking (Project 7.2) are projected to be $0. For the CAIR/CAMR Crystal River Program (Project 7.4), O&M is forecasted be $19.9M.

**Project Progress Summary:**
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program.

**Project Projections:**
2022 estimated O&M expenditures are $7.6M.

**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 2021.

**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 2022.

**Project Title:** **Arsenic Groundwater Standard**
**Project No. 8**

**Project Description:**
On 12/22/01, the EPA adopted a new maximum contaminant level (MCL) for arsenic in drinking water replacing the previous standard of 0.050 mg/L (50 ppb) with a new MCL of 0.010 mg/L (10 ppb). Effective 1/1/05, the FDEP established the USEPA MCL as Florida's drinking water standard. See Rule 62-550 F.A.C. The new standard has compliance implications for land application and water reuse projects in Florida with arsenic ground water monitoring levels above 10 ppb because the drinking water standard has been established as the groundwater standard by Rule 62-520-420(1), F.A.C.

**Project Accomplishments:**
A Plan of Study (POS) to evaluate the source of arsenic at the site was implemented on November 2011. A POS Addendum that included a leachability study and proposed abandoning one well and installing 3 new wells was implemented in February 2012. An additional Flue Gas Desulfurization (FGD) Wastewater Treatment Study was conducted in May 2013. The results of these studies indicated that Arsenic is naturally occurring in some areas but there is also a contribution from the FGD discharge from the lined treatment pond to the percolation ponds, and from the industrial wastewater from Crystal River Units 1 & 2. These sources are being addressed by the construction of a new FGD wastewater treatment system and retirement of Units 1 & 2, both scheduled to be completed by December 31, 2018.
Additional assessment was initiated in 2016 around the area of ground water wells still exceeding the Arsenic standard of 10 ppb with no clear source of Arsenic identified (MWC-1, MWC-31 and MWC-32). This additional assessment indicated that the source of Arsenic around MWC-31 is related to the former North Ash Pond that was located in that area. Based on that finding, the Consent Order was amended to address that area under 62-780, F.A.C. Remedial Actions, which included additional assessment and submittal of a final assessment report to FDEP in 2018.
Results from MWC-1 assessment indicate that the well is not measuring impacts from the industrial wastewater activities at the site and DEF requested to FDEP that the well be replaced by one of the Plan of Study wells. FDEP requested the sampling of all the wells around MWC-1 for a year prior to approval of the change.

**Project Fiscal Expenditures:**
2021 O&M expenditures are expected to be $269k.

**Project Progress Summary:**
Continuation of groundwater monitoring, analysis and reporting of results to FDEP.

**Project Projections:**
2022 O&M expenditures are forecasted to be $74k.

**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:**
2021 Capital expenditures are estimated to be $0, O&M expenditures are estimated to be a $0.

**Project Progress Summary:**
DEF is on schedule with activities identified for this program.

This project was moved to base rates as of January 2022, as approved in Order No. PSC-2021-0202-AS-EI.

**Project Projections:**
There are no Capital or O&M costs estimated for 2022.

**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 2021 estimated expenditures for this project.

**Project Progress Summary:**
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

This project was moved to base rates as of January 2022, as approved in Order No. PSC-2021-0202-AS-EI.

**Project Projections:**
No 2022 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 2021 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 2022 expenditures are expected for this project.

**Project Title:** **Crystal River Thermal Discharge Compliance Project**
**Project No. 11.1**

**Project Description:**
This project was to evaluate and implement the best long term solution to maintain compliance with the thermal discharge limit in the FDEP industrial wastewater permit for Crystal River Units 1,2&3 that was being addressed in the short term by the Modular Cooling Towers approved in Docket No. 20060162-EI. Due to DEF's decision to retire CR3, this project is no longer necessary and will not be implemented.

**Project Accomplishments:**
The study phase of the project was completed with a recommendation to replace the leased modular cooling towers in coordination with the cooling solution for the CR3 Extended Power Uprate (EPU) discharge canal cooling solution. The new cooling tower associated with the CR3 EPU was to be sized to mitigate both increased temperatures from the EPU as well as replace the modular cooling towers, which were removed in 2012. The design contract for the CR3 EPU cooling tower was awarded and a vendor selected. In February 2013, DEF decided to retire CR3; therefore, the project will not proceed.

**Project Fiscal Expenditures:**
There are no 2021 estimated expenditures for this project.

**Project Progress Summary:**
Crystal River Units 1,2&3 utilize a once-through cooling water process to cool and condense turbine exhaust steam back to water. The cooling water is removed from the Gulf of Mexico via an intake canal and discharged to a common discharge canal shared by all of the generating units. DEF has a NPDES industrial wastewater permit from the FDEP to discharge this cooling water from CR 1,2&3 into the Gulf of Mexico. The FDEP NPDES permit includes a limit on the temperature of the cooling water discharge (96.5 degrees Fahrenheit on a three-hour rolling average) measured at the point of discharge to the Gulf of Mexico. The new cooling towers were being added as a long term solution to the issue of higher ambient water temperatures previously being addressed by the modular cooling towers and added heat rejection due to the estimated 180MW Uprate of CR3. With the retirement of CR3, the heat rejection associated with the entire unit is removed and therefore the new cooling tower is not necessary for the continued operation of CR 1&2 within the NPDES permit limits.

**Project Projections:**
No 2022 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 2021 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 2022 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 2021 estimated expenditures for this project.

**Project Progress Summary:**
The mercury TMDL study concluded in 2012.

**Project Projections:**
No 2022 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 2021 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA during 2010.

**Project Projections:**
No 2022 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 2021 estimated expenditures for this project.

**Project Progress Summary:**
DEF completed and submitted the ICR to EPA in September 2010.

**Project Projections:**
No 2022 expenditures are expected for this project.

**Project Title:** **Effluent Limitation Guidelines CRN Program**
**Project No. 15.1**

**Project Description:**
On September 30th, 2015, U.S. Environmental Protection Agency finalized the Steam Electric Power Generating Effluent Guidelines, 40 CFR Part 423, imposing federal standards on several power plant streams that are discharged to surface water. In the final regulation, closed-loop systems or dry handling have been identified as the Best Available Technology ("BAT") for bottom ash transport water. Crystal River North Units 4 & 5 have a dry bottom ash system that utilizes dewatering bins for separation of bottom ash and water. However, the current configuration has the potential for bottom ash transport water to leave via overflows and drain into an NPDES internal outfall. Achieving the closed loop bottom ash compliance requirement is as soon as possible beginning November 1, 2018 but no later than December 31, 2023. Renewal of the Crystal River Units 4 & 5 NPDES permit is in progress and addresses this requirement. Duke Energy is seeking a compliance date of February 1, 2020 to include modification of the existing system.

**Project Accomplishments:**
DEF Initiated the first phase of ELG compliance activities necessary to comply with NPDES permit renewal. The remaining project scope is still on hold pending EPA Administrative Stay final decision.

**Project Fiscal Expenditures:**
There are no 2021 estimated expenditures for this project.

**Project Progress Summary:**
This project was placed in-service June 2020.

**Project Projections:**
No capital or O&M expenditures are forecasted for 2022.

**Project Title:** **National Pollutant Discharge Elimination System (NPDES)**
**Project No. 16**

**Project Description:**
Pursuant to the Federal Clean Water Act, 33 U.S.C. § 1342, all point source discharges to navigable waters from industrial facilities must obtain permits under the NPDES Program. The FDEP administers the NPDES program in Florida. DEF's Anclote, Bartow, and Crystal River North, Crystal River South, and Suwannee NPDES permits were issued on 11/25/2015, 1/5/2016, 7/18/11, 4/7/2014, and 10/6/2016, respectively. Crystal River North NPDES permit is in the renewal process. All facilities are required to meet new permitting conditions. In Docket No. 20110007-EI, the Commission approved recovery of costs associated with new requirements included or expected to be included in the new renewal permits, including: thermal studies, aquatic organism return studies and implementation, whole effluent toxicity (WET) testing, dissolved oxygen (DO) studies (Bartow only), and freeboard limitation related studies (Bartow only). As noted in DEF's 2/8/12 program update, on 12/14/11, the FDEP issued a final NPDES renewal permit and associated Administrative Order (AO) for the Suwannee Plant. The AO includes a new requirement to assess copper discharges that DEF did not anticipate when it filed its petition in 2011.

**Project Accomplishments:**
DEF continues to perform whole effluent toxicity testing, implementing initial 316(b) rule requirements based on NPDES permit schedules at affected facilities which includes literature review and analysis, additional field study, and reporting requirements in accordance to NPDES permit requirements. Bartow freeboard limitation study was completed in May 2011 and submitted to FDEP on 6/23/11. The FDEP approved DEF's corrective action plan and Bartow is in compliance with Administrative Order as of December 2014. The copper discharge study at the Suwannee plant has been completed and a final report was submitted to the FDEP in June 2014 resulting in a corrective action of retiring the steam units. The Suwannee plant retired Units 1, 2 and 3 in December 2016.

**Project Fiscal Expenditures:**
2021 O&M expenditures are estimated to be $52k. No capital expenditures are forecasted for 2021.

**Project Progress Summary:**
DEF has begun complying with the requirements of the NPDES permits. Aquatic organism return study requirements have been postponed to align with the final EPA 316(b) rule requirements (Bartow/Anclote Plants) which was published 8/15/14. The aquatic organism return requirement is not a requirement in the Crystal River North NPDES permit. The dissolved oxygen study of cooling water intake and discharge at the Bartow plant was completed and the results of the study demonstrated there is no negative impact on DO due to the plant's operation. The final DO report was submitted to the FDEP on November 20, 2012, and the Department has not required any additional action. The Suwannee Steam station was retired and removed from service; therefore, WET testing is no longer required.

**Project Projections:**
2022 estimated O&M expenditures are $32k. No capital expenditures are expected in 2022.

**Project Title:** **Mercury & Air Toxic Standards (MATS) CR4 & CR5**
**Project No. 17**

**Project Description:**
The Commission approved ECRC recovery of DEF's costs for compliance with new hazardous air pollutant standards at Crystal River Units 4 & 5 (CR4&5) in Order No. PSC-2011-0553-FOF-EI. The final MATS rule was issued by the EPA on 12/21/11. The FDEP granted a limited, one-year extension for the mercury-related requirements on 3/12/15. DEF will utilize the co-benefits of existing FGD and SCR systems as the primary MATS emission controls. CR4&5 have demonstrated compliance with all MATS requirements as of 4/16/16.

**Project Accomplishments:**
DEF installed oxidation-reduction potential (ORP) probes and mercury re-emission control systems for MATS emissions control. In addition, continuous emissions monitoring systems (CEMS) were installed for compliance demonstration with particulate matter (PM) and mercury emissions. Appendix K sorbent traps have been certified and maintained to serve as backup monitors for mercury CEMS.

**Project Fiscal Expenditures:**
2021 O&M expenditures are estimated to be $245K.

**Project Progress Summary:**
Initial implementation of the CR4&5 MATS compliance plan is complete.

**Project Projections:**
2022 estimated O&M is $191k. No capital expenditures are forecasted.

**Project Title:** **Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion**
**Project No. 17.1**

**Project Description:**
Convert existing Anclote Units to use 100% natural gas to be in compliance with MATS as approved by the Commission in Order No. PSC-2012-0432-PAA-EI.

**Project Accomplishments:**
Unit 1 and Unit 2 gas conversions were completed 7/13/13 and 12/2/13, respectively. Unit 1 and Unit 2 Forced Draft (FD) fan modification work was completed 5/22/14 and 11/17/14, respectively.

**Project Fiscal Expenditures:**
No 2021 expenditures are expected for this project.

**Project Progress Summary:**
This project is in-service.

This project was moved to base rates as of January 2022 per Order No. PSC-2021-0202-AS-EI.

**Project Projections:**
No 2022 expenditures are expected for this project.

**Project Title:** **Mercury & Air Toxic Standards (MATS) CR1 & CR2**
**Project No. 17.2**

**Project Description:**
DEF implemented its CR1&2 MATS Compliance Plan as approved by the Commission in Order No. PSC-2014-0173-PAA-EI. CR1&2 have demonstrated compliance with all MATS requirements as of 4/16/2016.

**Project Accomplishments:**
DEF finalized its CR1&2 MATS Compliance Plan in December 2013 and began implementation in early 2014. Modifications were made to the electrostatic precipitators (ESPs) to improve particulate collection efficiency, and reagent injection systems were installed to reduce hydrogen chloride (HCl) and mercury emissions. Appendix K sorbent traps were installed for compliance demonstration with mercury emissions.

**Project Fiscal Expenditures:**
No further Capital or O&M expenses are forecasted.

**Project Progress Summary:**
CR1&2 have been retired as of December 2020.

**Project Projections:**
No further Capital or O&M expenses are forecasted.

**Project Title:** **Coal Combustion Residual (CCR) Rule**
**Project No. 18**

**Project Description:**
The Coal Combustion Residual (CCR) Rule was published in the Federal Register on 4/17/15 and is effective 10/19/15. This rule regulates the disposal of CCR as non-hazardous solid waste, and contains new requirements for CCR landfills and CCR surface impoundments. It also specifies implementation guidelines for compliance. The CCR compliance deadlines vary, with compliance obligations required as early as 10/19/15. The rule is self-implementing, meaning that affected facilities must comply with the new regulations irrespective of whether the rule is adopted by the State of Florida. The rule has specific impacts on the ash landfill, Flue Gas Desulfurization (FGD) lined blowdown ponds and temporary gypsum pad at the Crystal River site. No other DEF operating facilities are impacted by the CCR rule.

**Project Accomplishments:**
Annual inspections were completed for the FGD Blowdown Ponds and Ash Landfill. Maintenance, vegetation management, and weekly inspections for the FGD Blowdown Ponds and Ash Landfill continue. The groundwater assessment project for the FGD Blowdown Ponds and Ash Landfill continued per the requirements of the rule.

**Project Fiscal Expenditures:**
2021 estimated O&M expenditures are $752k. Capital forecast is $1.8M.

**Project Progress Summary:**
Ash Landfill: currently O&M work to remove some accumulated CCR material in the perimeter ditch, also some capital work after that for a new lined basin / ditch area, which will help avoid further accumulation in the future. Expected completion in 2021.

FGD Blowdown Ponds: Dewatering and solids removal from the primary and backup FGD Blowdown Ponds were completed. Pond closure was completed 2020, and alternative source demonstration was completed to address statistically significant increases in certain constituents in groundwater.

Lined sedimentation basin expected to be complete in 2021.

Vegetation Management & Inspection Work: More frequent mowing and inspection work is being performed, to comply with the CCR Rule.

**Project Projections:**
2022 estimated O&M expenditures are $343k. No capital expenditures are forecasted.

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of the Energy & Demand Allocation % by Rate Class**
**January 2022 - December 2022**

| Rate Class | (1) Average 12CP Load Factor at Meter (%) | (2) Sales at Meter (mWh) | (3) Avg 12 CP at Meter (MW) (2)/(8760hrsx(1)) | (4) NCP Class Max Load Factor | (5) Delivery Efficiency Factor | (6) Sales at Source (Generation) (mWh) (2)/(5) | (7) Avg 12 CP at Source (MW) (3)/(5) | 7(a) Sales at Source (Distrib Svc Only) (mWh) | (8) Class Max MW at Source Level (Distrib Svc) (7a)/(8760hrs/(4)) | (9) mWh Sales at Source Energy Allocator (%) | (10) 12CP Demand Transmission Allocator (%) | (11) NCP Distribution Allocator (%) | (12) 12CP & 25% AD Demand Allocator (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | | | | | |
| **RS-1, RST-1, RSL-1, RSL-2, RSS-1** | | | | | | | | | | | | | |
| Secondary | 0.516 | 21,211,130 | 4,691.51 | 0.438 | 0.9361197 | 22,658,567 | 5,011.65 | 22,658,567 | 5,907.7 | 54.164% | 64.006% | 63.000% | 61.546% |
| **General Service Non-Demand** | | | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | | | |
| Secondary | 0.608 | 1,018,417 | 191.23 | 0.436 | 0.9361197 | 1,087,914 | 204.28 | 1,087,914 | 284.6 | 2.601% | 2.609% | 3.035% | 2.607% |
| Primary | 0.608 | 18,782 | 3.53 | 0.436 | 0.9759311 | 19,246 | 3.61 | 19,246 | 5.0 | 0.046% | 0.046% | 0.054% | 0.046% |
| Sec Del/Primary Mtr | 0.608 | 42 | 0.01 | 0.436 | 0.9759311 | 43 | 0.01 | 43 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| Transmission | 0.608 | 2,666 | 0.50 | 0.436 | 0.9859311 | 2,704 | 0.51 | 0 | 0.0 | 0.006% | 0.006% | 0.000% | 0.006% |
| | | | | | | | | | | 2.653% | 2.662% | 3.089% | 2.660% |
| **General Service** | | | | | | | | | | | | | |
| **GS-2** Secondary | 1.000 | 204,533 | 23.35 | 1.000 | 0.9361197 | 218,490 | 24.94 | 218,490 | 24.9 | 0.522% | 0.319% | 0.266% | 0.369% |
| **General Service Demand** | | | | | | | | | | | | | |
| **GSD-1, GSDT-1** | | | | | | | | | | | | | |
| Secondary | 0.742 | 11,642,447 | 1,791.32 | 0.587 | 0.9361197 | 12,436,921 | 1,913.56 | 12,436,921 | 2,419.7 | 29.730% | 24.439% | 25.804% | 25.762% |
| Primary | 0.742 | 1,638,508 | 252.10 | 0.587 | 0.9759311 | 1,678,917 | 258.32 | 1,678,917 | 326.6 | 4.013% | 3.299% | 3.483% | 3.478% |
| Secondary Del/ Primary Mtr | 0.742 | 24,351 | 3.75 | 0.587 | 0.9759311 | 24,952 | 3.84 | 24,952 | 4.9 | 0.060% | 0.049% | 0.052% | 0.052% |
| Transm Del/ Primary Mtr | 0.742 | 0 | 0.00 | 0.587 | 0.9759311 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| Transmission | 0.742 | 401,077 | 61.71 | 0.587 | 0.9859311 | 406,800 | 62.59 | 0 | 0.0 | 0.972% | 0.799% | 0.000% | 0.843% |
| **SS-1** Primary | 0.958 | 48,108 | 5.73 | 0.456 | 0.9759311 | 49,294 | 5.87 | 49,294 | 12.4 | 0.118% | 0.075% | 0.132% | 0.086% |
| Transm Del/ Transm Mtr | 0.958 | 3,723 | 0.44 | 0.456 | 0.9859311 | 3,776 | 0.45 | 0 | 0.0 | 0.009% | 0.006% | 0.000% | 0.007% |
| Transm Del/ Primary Mtr | 0.958 | 1,546 | 0.18 | 0.456 | 0.9759311 | 1,585 | 0.19 | 0 | 0.0 | 0.004% | 0.002% | 0.000% | 0.003% |
| | | | | | | | | | | 34.906% | 28.670% | 29.471% | 30.229% |
| **Curtailable** | | | | | | | | | | | | | |
| **CS-2, CST-2, SS-3** | | | | | | | | | | | | | |
| Secondary | 1.028 | 0 | 0.00 | 0.358 | 0.9361197 | 0 | 0.00 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| Primary | 1.028 | 62,060 | 6.89 | 0.358 | 0.9759311 | 63,590 | 7.06 | 63,590 | 20.3 | 0.152% | 0.090% | 0.216% | 0.106% |
| **SS-3** Primary | 2.390 | 58,185 | 2.78 | 0.314 | 0.9759311 | 59,620 | 2.85 | 59,620 | 21.7 | 0.143% | 0.036% | 0.231% | 0.063% |
| | | | | | | | | | | 0.295% | 0.127% | 0.447% | 0.169% |
| **Interruptible** | | | | | | | | | | | | | |
| **IS-2, IST-2** | | | | | | | | | | | | | |
| Secondary | 0.957 | 406,762 | 48.52 | 0.732 | 0.9361197 | 434,520 | 51.83 | 434,520 | 67.7 | 1.039% | 0.662% | 0.722% | 0.756% |
| Sec Del/Primary Mtr | 0.957 | 5,152 | 0.61 | 0.732 | 0.9759311 | 5,279 | 0.63 | 5,279 | 0.8 | 0.013% | 0.008% | 0.009% | 0.009% |
| Primary Del / Primary Mtr | 0.957 | 1,171,449 | 139.72 | 0.732 | 0.9759311 | 1,200,340 | 143.17 | 1,200,340 | 187.1 | 2.869% | 1.828% | 1.995% | 2.089% |
| Primary Del / Transm Mtr | 0.957 | 226 | 0.03 | 0.732 | 0.9859311 | 229 | 0.03 | 229 | 0.0 | 0.001% | 0.000% | 0.000% | 0.000% |
| Transm Del/ Transm Mtr | 0.957 | 599,084 | 71.46 | 0.732 | 0.9859311 | 607,632 | 72.47 | 0 | 0.0 | 1.453% | 0.926% | 0.000% | 1.057% |
| Transm Del/ Primary Mtr | 0.957 | 429,008 | 51.17 | 0.732 | 0.9759311 | 439,588 | 52.43 | 0 | 0.0 | 1.051% | 0.670% | 0.000% | 0.765% |
| **SS-2** Primary | 1.147 | 13,316 | 1.32 | 0.306 | 0.9759311 | 13,644 | 1.36 | 13,644 | 5.1 | 0.033% | 0.017% | 0.054% | 0.021% |
| Transm Del/ Transm Mtr | 1.147 | 1,250 | 0.12 | 0.306 | 0.9859311 | 1,268 | 0.13 | 0 | 0.0 | 0.003% | 0.002% | 0.000% | 0.002% |
| Transm Del/ Primary Mtr | 1.147 | 44,422 | 4.42 | 0.306 | 0.9759311 | 45,518 | 4.53 | 0 | 0.0 | 0.109% | 0.058% | 0.000% | 0.071% |
| | | | | | | | | | | 6.569% | 4.171% | 2.781% | 4.770% |
| **Lighting** | | | | | | | | | | | | | |
| **LS-1** (Secondary) | 11.683 | 348,815 | 3.41 | 0.479 | 0.9361197 | 372,618 | 3.64 | 372,618 | 88.8 | 0.891% | 0.046% | 0.947% | 0.258% |
| | | 39,355,060 | 7,355.81 | | | 41,833,056 | 7,829.95 | 40,324,184 | 9,377.3 | 100.000% | 100.000% | 100.000% | 100.000% |

Notes:

(1) Average 12CP load factor based on load research study filed July 30, 2021
(2) Projected kWh sales for the period January 2022 to December 2022
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) NCP load factor based on load research study filed July 30, 2021
(5) Based on system average line loss analysis for 2020
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,760 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 8/ Total Column 8
(12) (Column 9 x .25) + (Column 10 x .75)

**DUKE ENERGY FLORIDA, LLC**
**Environmental Cost Recovery Clause**
**Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class**
**January 2022 - December 2022**

| Rate Class | (1) mWh Sales at Source Energy Allocator (%) | (2) 12CP Transmission Demand Allocator (%) | (3) NCP Distribution Allocator (%) | (4) 12CP & 25% AD Demand Allocator (%) | (5) Energy-Related Costs ($) | (6) Transmission Demand Costs ($) | (7) Distribution Demand Costs ($) | (8) Production Demand Costs ($) | (9) Total Environmental Costs ($) | (10) Projected Effective Sales at Meter Level (mWh) | **(11) Environmental Cost Recovery Factors (cents/kWh)** |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | | | |
| **RS-1, RST-1, RSL-1, RSL-2, RSS-1** | | | | | | | | | | | |
| Secondary | 54.164% | 64.006% | 63.000% | 61.546% | $3,676,241 | ($1,401) | ($412) | $2,255,317 | $5,929,746 | 21,211,130 | **0.028** |
| **General Service Non-Demand** | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 1,018,417 | **0.027** |
| Primary | | | | | | | | | | 18,636 | **0.027** |
| Transmission | | | | | | | | | | 2,613 | **0.026** |
| **TOTAL GS** | 2.653% | 2.662% | 3.089% | 2.660% | $180,077 | ($58) | ($20) | $97,458 | $277,456 | **1,039,667** | |
| **General Service** | | | | | | | | | | | |
| **GS-2** Secondary | 0.522% | 0.319% | 0.266% | 0.369% | $35,449 | ($7) | ($1.74) | $13,539.45 | $48,980 | 204,533 | **0.024** |
| **General Service Demand** | | | | | | | | | | | |
| **GSD-1, GSDT-1, SS-1** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 11,642,447 | **0.025** |
| Primary | | | | | | | | | | 1,695,388 | **0.025** |
| Transmission | | | | | | | | | | 396,704 | **0.025** |
| **TOTAL GSD** | 34.906% | 28.670% | 29.471% | 30.229% | $2,369,142 | ($627) | ($193) | $1,107,721 | $3,476,043 | **13,734,539** | |
| **Curtailable** | | | | | | | | | | | |
| **CS-2, CST-2, CS-3, CST-3, SS-3** | | | | | | | | | | | |
| Secondary | | | | | | | | | | - | **0.022** |
| Primary | | | | | | | | | | 119,042 | **0.022** |
| Transmission | | | | | | | | | | - | **0.022** |
| **TOTAL CS** | 0.295% | 0.127% | 0.447% | 0.169% | $19,990 | ($3) | ($3) | $6,177 | $26,162 | **119,042** | |
| **Interruptible** | | | | | | | | | | | |
| **IS-2, IST-2, SS-2** | | | | | | | | | | | |
| Secondary | | | | | | | | | | 406,762 | **0.023** |
| Primary | | | | | | | | | | 1,646,714 | **0.023** |
| Transmission | | | | | | | | | | 588,548 | **0.023** |
| **TOTAL IS** | 6.569% | 4.171% | 2.781% | 4.770% | $445,852 | ($91) | ($18) | $174,808 | $620,551 | **2,642,025** | |
| **Lighting** | | | | | | | | | | | |
| **LS-1** Secondary | 0.891% | 0.046% | 0.947% | 0.258% | $60,455 | ($1) | ($6.19) | $9,438.04 | $69,886 | 348,815 | **0.020** |
| | 100.000% | 100.000% | 100.000% | 100.000% | $6,787,207 | ($2,188) | ($654) | $3,664,458 | $10,448,824 | 39,299,750 | **0.027** |

Notes:
(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 10
(3) From Form 42-6P, Column 11
(4) From Form 42-6P, Column 12
(5) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(6) Column 2 x Total Transmission Demand Jurisdictional Dollars from Form 42-1P, line 5
(7) Column 3 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
(8) Column 4 x Total Production Demand Jurisdictional Dollars from Form 42-1P, line 5
(9) Column 5 + Column 6 + Column 7 + Column 8
(10) Projected kWh sales at secondary voltage level for the period January 2022 to December 2022
(11) (Column 9 / Column 10)/10

| | | (1) | (2) | (3) | (4) | (5) | (6) |
|---|---|---|---|---|---|---|---|
| | | Jurisdictional Rate Base Adjusted Retail ($000s) | Cap Ratio | Cost Rate | Weighted Cost | Revenue Requirement Rate | Monthly Revenue Requirement Rate |
| 1 | Common Equity | $ 7,302,840 | 43.96% | 9.85% | 4.330% | 5.80% | 0.4833% |
| 2 | Long Term Debt | 6,603,424 | 39.75% | 4.11% | 1.635% | 1.63% | 0.1358% |
| 3 | Short Term Debt | 74,501 | 0.45% | 1.66% | 0.007% | 0.01% | 0.0008% |
| 4 | Cust Dep Active | 182,161 | 1.10% | 2.36% | 0.026% | 0.03% | 0.0025% |
| 5 | Cust Dep Inactive | 1,888 | 0.01% | | | 0.00% | 0.0000% |
| 6 | Invest Tax Cr | 215,728 | 1.30% | 7.13% | 0.093% | 0.12% | 0.0100% |
| 7 | Deferred Inc Tax | 2,230,499 | 13.43% | | | 0.00% | 0.0000% |
| 8 | **Total** | **$ 16,611,041** | **100.00%** | | **6.09%** | **7.59%** | **0.6325%** |

| | ITC split between Debt and Equity**: | | Ratio | Cost Rate | Ratio | Ratio | Deferred Inc Tax | Weighted ITC | After Gross-up |
|---|---|---|---|---|---|---|---|---|---|
| 9 | Common Equity | 7,302,840 | 53% | 9.85% | 5.17% | 72.6% | 0.09% | 0.067% | 0.090% |
| 10 | Preferred Equity | - | 0% | | | | 0.09% | 0.000% | 0.000% |
| 11 | Long Term Debt | 6,603,424 | 47% | 4.11% | 1.95% | 27.4% | 0.09% | 0.025% | 0.025% |
| 12 | ITC Cost Rate | 13,906,264 | 100% | | 7.13% | | | 0.093% | 0.115% |

Breakdown of Revenue Requirement Rate of Return between Debt and Equity:

| | | | |
|---|---|---|---|
| 13 | Total Equity Component (Lines 1 and 9 ) | 5.890% | Total Pre-Tax Equity |
| 14 | Total Debt Component (Lines 2, 3 , 4 , and 11 ) | 1.695% | Total Debt |
| 15 | **Total Revenue Requirement Rate of Return** | 7.585% | WACC |

Notes:

Effective Tax Rate: 25.345%

Column:

(1) Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology
(2) Column (1) / Total Column (1)
(3) Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology
Line 6 and Line 12, the cost rate of ITC's is determined under Treasury Regulation section 1.46-6(b)(3)(ii).
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-effective income tax rate/100)
* For debt components: Column (4)
** Line 6 is the pre-tax ITC components from Lines 9 and 11
(6) Column (5) / 12

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

DIRECT TESTIMONY OF

KIM SPENCE McDANIEL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

August 27, 2021

**Q. Please state your name and business address.**

A. My name is Kim Spence McDaniel. My business address is 299 1st Avenue North, St. Petersburg, FL 33701.

**Q. Have you previously filed testimony before this Commission in Docket No. 20210007-EI?**

A. Yes. I provided direct testimony on April 1, 2021, and July 30, 2021.

**Q. Has your job description, education, background or professional experience changed since that time?**

A. No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide estimates of the costs that will be incurred in 2022 for Duke Energy Florida, LLC's ("DEF" or "the Company") Substation Environmental Investigation, Remediation and Pollution Prevention

Program (Project 1 & 1a), Distribution Environmental Investigation, Remediation and Pollution Prevention Program (Project 2), Pipeline Integrity Management ("PIM") Program (Project 3), Above Ground Storage Tanks ("AST") Program (Project 4), Phase II Cooling Water Intake 316(b) Program (Project 6), CAIR/CAMR Continuous Mercury Monitoring System ("CMMS") Program (Projects 7.2 & 7.3), Best Available Retrofit Technology ("BART") Program (Project 7.5), Arsenic Groundwater Standard Program (Project 8), Sea Turtle – Coastal Street Lighting Program (Project 9), Underground Storage Tanks ("UST") Program (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge Permanent Compliance (Project 11.1), Greenhouse Gas Inventory and Reporting (Project 12), Mercury Total Maximum Loads Monitoring ("TMDL") (Project 13), Hazardous Air Pollutants ("HAPs") Information Collection Request ("ICR") (Project 14), Effluent Limitation Guidelines CRN (Project 15.1) and National Pollutant Discharge Elimination System ("NPDES") Program (Project 16).

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

**A.** Yes. I am co-sponsoring the following portions of Exhibit No.__(GPD-5) to Gary P. Dean's Direct Testimony:

- 42-5P, p. 1 of 23 – Substation Environmental Investigation, Remediation and Pollution Prevention Program
- 42-5P, p. 2 of 23 - Distribution System Environmental Investigation, Remediation and Pollution Prevention Program

- 42-5P, p. of 23 – PIM
- 42-5P, p. 4 of 23 - AST
- 42-5P, p. 6 of 23 - Phase II Cooling Water Intake
- 42-5P, p.7 of 23 – Clean Air Interstate Rule ("CAIR")
- 42-5P, p. 8 of 23 – BART
- 42-5P, p. 9 of 23 - Arsenic Groundwater Standard
- 42-5P, p. 10 of 23 – Sea Turtle – Coastal Street Lighting Program
- 42-5P, p.11 of 23 - UST
- 42-5P, p. 12 of 23 - Modular Cooling Towers
- 42-5P, p. 13 of 23 - Thermal Discharge Permanent Cooling Tower
- 42-5P, p. 14 of 23 - Greenhouse Gas Inventory and Reporting
- 42-5P, p. 15 of 23 - Mercury TMDL
- 42-5P, p. 16 of 23 - HAPs ICR
- 42-5P, p. 17 of 23 - Effluent Limitation Guidelines ICR Program
- 42-5P, p.18 of 23 - Effluent Limitation Guidelines CRN Program
- 42-5P, p. 19 of 23 - NPDES

**Q. What O&M costs does DEF expect to incur in 2022 for the Phase II Cooling Water Intake 316(b) Program for Anclote and Bartow CC stations (Projects 6 and 6a)?**

A. DEF is forecasting a total of $280k in O&M costs for the Phase II Cooling Water Intake Program 316(b) projects in 2022.

DEF estimates approximately $260k of O&M costs for the Anclote Station to develop and begin implementation of a Plan of Study ("Study"). DEF anticipates receiving the final NPDES permit renewal from the Florida Department of Environmental Protection ("FDEP") by year end 2021. If the permit requirements reflect what was proposed in the application, the permit will require DEF to prepare and implement a Study that evaluates organism mortality associated with the cooling water intake system. The Study will be conducted for a period of one to two years, potentially longer, depending upon results of the Study and FDEP response. The results of the Study will determine whether any future capital investments are necessary. The full extent of compliance activities and associated expenditures could change depending on the conditions of the final NPDES permit when issued.

DEF estimates approximately $20k of O&M for Crystal River North to support consultations related to 316(b) topics, including source waterbody data, impingement, or entrainment data, and/or any threatened or endangered species. This estimate is provided in the event FDEP requests additional information.

**Q. What Capital costs does DEF expect to incur in 2022 for the Phase II Cooling Water Intake 316(b) Program for Anclote and Bartow CC stations (Projects 6.1 and 6.2)?**

A. DEF estimates the potential for $1.1M of capital costs in 2022 for the Bartow station 316(b) compliance plan for preliminary engineering and design of modified traveling screens and an organism return system. This estimate is

preliminary as DEF does not currently have a final NPDES permit renewal, and therefore the compliance strategy and schedule that the permit will require is unknown. The full extent of compliance activities and associated expenditures could change depending on the conditions of the final NPDES permit when issued.

As this estimate is preliminary and dependent on final approval from FDEP, the project scope and associated timeline are still undetermined and may change depending on the conditions required when the final NPDES permit is issued. However, based on assumptions used in the initial permit application, it is likely that the first two years after permit approval will involve selection of an engineering firm and detailed engineering work, along with initiation and selection of the screen vendor bid process, and initiation of procurement of screens and associated components.

Years three through six will likely include procurement of remaining components, contractor mobilization, installation of screens, contractor demobilization, development, submittal and implementation of an impingement optimization study plan and development and submission of the interim report. This is expected to conclude with the final report submittal. This schedule is high-level, and subject to the final permit from FDEP.

No Capital costs are projected for the Anclote Station for 2022, however this estimate is preliminary as DEF does not currently have a final NPDES permit

renewal, and therefore the compliance requirements of the permit are unknown.

**Q. What costs does DEF expect to incur in 2022 for the Arsenic Groundwater Standard Program (Project 8)?**

A. DEF forecasts 2022 O&M expenditures to be $74k. Anticipated costs are associated with post-remediation groundwater monitoring, implementation of a deed restriction and restrictive covenant for the affected area, final analysis and reporting of results to the agency and also monitoring well abandonment.

In accordance with FDEP Consent Order No. 09-3463D executed on March 22, 2016, and FDEP Consent Order No. 09-3463E executed on November 17, 2017, DEF's investigation has identified potential sources of arsenic exceedances in groundwater monitoring wells addressed in the Consent Order. The original Consent Order was issued by the FDEP for exceedance of the arsenic groundwater limit following the 2005 revision of the State's groundwater standard that lowered the arsenic maximum contaminant level from 50 ppb to 10 ppb. As discussed in the prior testimony of DEF Witness Patricia Q. West[1], the results of DEF's monitoring and assessment identified the need for additional compliance activities. On July 26, 2019, DEF submitted a Site Assessment Report Addendum ("SARA") addressing FDEP comments to the Site Assessment Report ("SAR") submitted on August 31, 2018. The SAR and SARA documents all assessment work done under the Consent Order to identify the nature and extent of arsenic in

[1] Please see Ms. West's direct testimony provided in Docket Nos. 2005007-EI, 20080007-EI, 20090007-EI and 20150007-EI.

groundwater. On October 15, 2019, FDEP notified DEF that sediment and soil assessment was complete and that additional ground water delineation was needed. On June 24, 2020, DEF submitted to FDEP a Site Assessment Status Report ("SASR") with additional ground water sampling results to complete the ground water delineation and a Soils and Sediment Management Plan to be implemented for remediation of soils and sediments in the former North Ash Pond area. FDEP approved the plan on August 4, 2020. Remediation of soils and sediments in the North Ash Pond area was completed on January 7, 2021, and completion of the soil cap installation completed on April 6, 2021. On May 26, 2021, DEF submitted to FDEP a Site Assessment Report Addendum No. 2 and Natural Attenuation Monitoring Plan ("NAM"). The purpose of the NAM is to confirm that the arsenic concentrations in the former North Ash Pond Area are stable and/or decreasing after installation of the soil cap. The NAM was approved by FDEP and is being implemented by DEF. The report also included ground water monitoring conducted during March 2021. DEF and FDEP are in the process of amending the Consent Order to change the final date of compliance from December 31, 2021, to December 31, 2023, to allow additional time to obtain a Site Rehabilitation Completion Order ("SRCO") for the former North Ash Pond area.

**Q. What costs does DEF expect to incur in 2022 for the NPDES Program (Project No. 16)?**

A. DEF estimates $31k of O&M costs for Whole Effluent Toxicity ("WET") testing as required at DEF stations with NPDES permits.

**Q. Does this conclude your testimony?**

A. Yes.

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

DIRECT TESTIMONY OF

TIMOTHY HILL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

August 27, 2021

**Q. Please state your name and business address.**

A. My name is Timothy Hill. My business address is 400 South Tryon Street, Charlotte, NC 28202.

**Q. Have you previously filed testimony before this Commission in Docket No. 20210007-EI?**

A. Yes. I provided direct testimony on April 1, 2021, and July 30, 2021.

**Q. Has your job description, education, background or professional experience changed since that time?**

A. No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide an update on Duke Energy Florida, LLC's ("DEF" or "the Company") proposed compliance activities and related 2022 estimated costs associated with the Coal Combustion Residual ("CCR")

Rule for which the Company seeks recovery under the Environmental Cost Recovery Clause ("ECRC").

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

A. Yes. I am co-sponsoring the following portion of Exhibit No.__(GPD-5) to Gary P. Dean's Direct Testimony:

- 42-5P, p. 23 – Coal Combustion Residual Rule

**Q. What O&M costs does DEF expect to incur in 2022 for the Coal Combustion Residual Rule Program (Project No. 18)?**

A. DEF is forecasting $343k in O&M costs for 2022.

Various maintenance and repair work is required for the ash landfill to comply with the rule. This includes maintenance of the landfill cover, vegetation management, fugitive dust mitigation, weekly inspections and cleanout of the lined-sedimentation pond and perimeter ditch which was installed this year as a groundwater corrective measure. DEF will also continue to perform the required groundwater monitoring for ash management units, which includes engineering, sampling, analysis and reporting.

**Q. What Capital costs does DEF expect to incur in 2022 for the Coal Combustion Residual Rule Program (Project No. 18)?**

A. DEF does not expect capital expenditures in 2022.

**Q. Are there any other CCR rule compliance activities and costs for which DEF expects to seek recovery in 2022?**

A. DEF continues to evaluate the CCR rule to determine operating and cost impacts and expects to incur costs in 2022 and beyond. Additional compliance activities may be required as a result of ongoing, groundwater-quality monitoring to evaluate the effectiveness of the corrective measures implemented in 2020 and completed in 2021. As these monitoring and evaluation activities are completed, and if any additional compliance activities and costs become known, DEF will update the Commission and provide the costs for recovery, as appropriate, in later ECRC filings.

**Q. Does this conclude your testimony?**

A. Yes.

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

DIRECT TESTIMONY OF

REGINALD ANDERSON

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

August 27, 2021

**Q. Please state your name and business address.**

A. My name is Reginald Anderson. My business address is 299 1st Avenue North, St. Petersburg, FL 33701.

**Q. Have you previously filed testimony before this Commission in Docket No. 20210007-EI?**

A. Yes. I provided direct testimony on July 30, 2021, and adopted Jeffrey Swartz's testimony filed on April 1, 2021.

**Q. Has your job description, education, background, or professional experience changed since that time?**

A. No.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide estimates of ECRC-recoverable costs that will be incurred in 2022 for Duke Energy Florida, LLC's ("DEF" or "the

Company") environmental compliance programs under my responsibility. These programs include the CAIR/CAMR Crystal River ("CR") Program (Project 7.4), Mercury and Air Toxics Standards (MATS) – Crystal River (CR) 4&5 (Project 17), Mercury and Air Toxics Standards (MATS) – Anclote Gas Conversion (Project 17.1) and Mercury & Air Toxics Standards (MATS) – Crystal River 1&2 Program (Project 17.2).

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

A. Yes. I am co-sponsoring the following portions of Exhibit No. __ (GPD-5) to Gary P. Dean's direct testimony:

- Form 42-5P, p. 7 of 23 – Clean Air Interstate Rule (CAIR)
- Form 42-5P, p. 20 of 23 - MATS – CR4&5
- Form 42-5P, p. 21 of 23 - MATS – Anclote Gas Conversion
- Form 42-5P, p. 22 of 23 - MATS – CR1&2

**Q. What O&M costs does DEF expect to incur in 2022 for the CAIR/CAMR Crystal River – Energy Program (Project 7.4)?**

A. DEF estimates O&M costs of approximately $7.6M to support reagent and bi-product costs (ammonia, limestone, hydrated lime, caustic, dibasic acid and net gypsum sales/disposal) for use at the CR Energy Complex ("CREC") as outlined in DEF's Integrated Clean Air Compliance Plan.

**Q. What O&M costs does DEF expect to incur in 2022 for the MATS Program**

**– CR 4&5 (Project No. 17)?**

A. DEF estimates O&M costs of approximately $191k for CR 4&5 MATS compliance. This estimate includes emissions testing, burner inspections, maintenance of emissions monitoring and control technologies, and reagent costs.

**Q. Does this conclude your testimony?**

A. Yes.