DUKE ENERGY
FLORIDA

Matthew R. Bernier
Associate General Counsel

April 1, 2022

VIA ELECTRONIC FILING

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

Re: *Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor;* Docket No. 20220001-EI

Dear Mr. Teitzman:

On behalf of Duke Energy Florida, LLC ("DEF"), please find enclosed for electronic filing in the above-referenced docket:

- DEF's Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery Actual True-Ups for the Period of January 2021 through December 2021;
- Direct Testimony of Gary Dean with Exhibit No. ___ (GPD-1T), Exhibit No. ___ (GPD-2T), Exhibit No. ___ (GPD-3T), and Exhibit No. ___ (GPD-4T); and
- Redacted Direct Testimony of Anthony Salvarezza with Redacted Exhibit No. ___(AS-1), Redacted Exhibit No. ___(AS-1), and Redacted Exhibit No. ___(AS-3).

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/mw
Enclosures

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchase Power Cost Recovery Clause with Generating Performance Incentive Factor

Docket No. 20220001-EI

Filed: April 1, 2022

PETITION FOR APPROVAL OF FUEL COST RECOVERY AND CAPACITY COST RECOVERY WITH GENERATING PERFORMANCE INCENTIVE <u>FACTOR ACTUAL TRUE-UPS FOR THE PERIOD ENDING DECEMBER 2021</u>

Duke Energy Florida, LLC ("DEF"), hereby petitions the Florida Public Service Commission ("FPSC" or "Commission") for approval of DEF's actual Fuel and Purchased Power Cost Recovery ("FCR") true-up amount of $412,524,152 under-recovery and actual Capacity Cost Recovery ("CCR") true-up amount of $6,031,782 over-recovery for the period ending December 2021. In support of this Petition, DEF states as follows:

1. The actual $412,524,152 FCR under-recovery for the period January 2021 through December 2021 was calculated in accordance with the methodology set forth in Schedule 1, page 2 of 2, attached to Order No. 10093, dated June 19, 1981. This calculation and the supporting documentation are contained in the prepared testimony and exhibits of DEF witness Gary P. Dean, which is being filed together with the Petition and is incorporated herein by reference.

2. By Order No. PSC-2022-0061-PCO-EI, the Commission approved DEF's total estimated 2021 period-ending under-recovery of $415,458,323. The actual FCR under-recovery including interest for the period January 2021 through December 2021 is $412,524,152. The $412,524,152 actual under-recovery, less the actual/estimated under-recovery of $415,458,323, results in a total over-recovery of $2,934,170.

3. The actual $6,031,782 CCR over-recovery for the period January 2021 through December 2021 was calculated in accordance with the methodology set forth in Order No. 25773, dated February 24, 1992. This calculation and the supporting documentation are contained in the prepared testimony and exhibits of DEF witness Gary P. Dean.

4. By Order Nos. PSC-2021-0442-FOF-EI and PSC-2021-0442A-FOF-EI, the Commission approved CCR Factors for the 12-month period commencing January 2022. These factors reflected an actual/estimated over-recovery, including interest, for the period January 2021 through December 2021 of $2,718,273. The actual over-recovery, including interest, for the period January 2021 through December 2021 is $6,031,782. The $6,031,782 actual over-recovery, less the actual/estimated over-recovery of $2,718,273, which is currently reflected in charges for the period beginning January 2022, results in a total over-recovery of $3,313,509.

WHEREFORE, DEF respectfully requests the Commission to approve the net $2,934,170 FCR over-recovery as the actual true-up amount for the period ending December 2021; and to approve the net $3,313,509 CCR over-recovery as the actual true-up amount for the period ending December 2021.

Respectfully submitted,

s/ Matthew R. Bernier

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 1st day of April, 2022.

s/Matthew R. Bernier
Attorney

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DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20220001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2021 - December 2021

DIRECT TESTIMONY OF
Gary P. Dean

April 1, 2022

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, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company"), as Rates and Regulatory Strategy Manager.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for DEF. These responsibilities include completion of regulatory financial reports and analysis of state, federal and local regulations and their impacts on DEF. In this capacity, I am responsible for DEF's Final True-Up, Actual/Estimated Projection and Projection Filings in the Fuel Adjustment Clause, Capacity Cost Recovery Clause and Environmental Cost Recovery Clause.

Q. Please describe your educational background and professional experience.

A. I joined DEF on April 27, 2020 as the Rates and Regulatory Strategy Manager. Prior to working at DEF, I was the Senior Manager, Optimization for Chesapeake Utilities Corporation ("CUC"). In this role, I was responsible for all pricing related to the company's natural gas retail business. Prior to working at CUC, I was the General Manager, Electric Operations for South Jersey Energy Company ("SJEC"). In that capacity I held P&L and strategic development responsibility for the company's electric retail book. Prior to working at SJEC I had various positions associated with rates and regulatory affairs. In these positions I was responsible for all rate and regulatory matters, including tariff and rate design, financial modeling and analysis, and ensuring accurate rates for billing. I received a Master of Business Administration from Rutgers University and a Bachelor of Science degree in Commerce and Engineering, majoring in Finance, from Drexel University.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide DEF's Fuel Adjustment Clause final true-up amount for the period of January 2021 through December 2021, and DEF's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared and attached to my true-up testimony as Exhibit No. __(GPD-1T), a Fuel Adjustment Clause true-up calculation and related schedules; Exhibit No. __(GPD-2T), a Capacity Cost Recovery Clause true-up calculation and related schedules; Exhibit No. __(GPD-3T), Schedules A1 through A3, A6, and A12 for December 2021, year-to-date; and Exhibit No. __(GPD-4T), with DEF's capital structure and cost rates. Schedules A1 through A9, and A12 for the year ended December 31, 2021, were filed with the Commission on January 20, 2022.

Q. What is the source of the data that you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data is taken from the books and records of the Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission, and any accounting rules and orders established by this Commission. The Company relies on the information included in this testimony and exhibits in the conduct of its affairs.

Q. Would you please summarize your testimony?

A. Per Order No. PSC-2022-0061-PCO-EI, the total estimated 2021 period-ending fuel under-recovery is $415.46 million. The actual under-recovery for

2021 is $412.52 million, resulting in a final fuel adjustment true-up over-recovery amount of $2.94 million. Exhibit No. __(GPD-1T).

Per Order Nos. PSC-2021-0442-FOF-EI and PSC-2021-0442A-FOF-EI, the estimated 2021 capacity cost recovery true-up amount was an over-recovery of $2.7 million. The actual amount for 2021 was an over-recovery of $6.0 million, resulting in a final capacity true-up over-recovery amount of $3.3 million. Exhibit No. __(GPD-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2021 for fuel cost recovery?

A. The actual ending balance as of December 31, 2021 for true-up purposes is an under-recovery of $412,524,152, as shown on Exhibit No. __(GPD-1T).

Q. How does this amount compare to DEF's estimated 2021 ending balance included in the Company's December 17, 2021 Midcourse Filing?

A. The actual true-up amount for the January 2021 - December 2021 period is an under-recovery of $412,524,152, which is $2,934,170 lower than the re-projected year end under-recovery balance of $415,458,323, as shown on Exhibit No. __(GPD-1T).

Q. How was the final true-up ending balance determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company monthly, updated to reflect the True-Up WACC as prescribed in Order No. PSC-2020-0165-PAA-EU.

Q. What factors contributed to the period-ending jurisdictional net over-recovery of $2,934,170 shown on your Exhibit No. __(GPD-1T)?

A. The $2.9 million is driven primarily by increased generation and purchased power costs of $7.1 million and $2.3 million, respectively, offset by $9.2 million higher sales.

Q. Please explain the components shown on Exhibit No. __(GPD-1T), sheet 6 of 6, which helps to explain the $3.5 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

A. Exhibit No. __(GPD-1T), sheet 6 of 6 is an analysis of the system dollar variance for each energy source in terms of three interrelated components; (1) changes in the <u>amount</u> (mWh's) of energy required; (2) changes in the <u>heat rate</u> of generated energy (BTU's per kWh); and (3) changes in the <u>unit price</u> of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per kWh). The $3.5 million unfavorable system variance is mainly attributable to higher natural gas generation and firm purchases, partially offset by lower coal generation and qualifying facilities costs.

Q. Does this period ending true-up balance include any noteworthy adjustments to fuel expense?

A. Yes. Noteworthy adjustments are shown on Exhibit No. __(GPD-3T) in the footnote to line 6b on page 1 of 2, Schedule A2.

Consistent with Order No. PSC-2018-0240-PAA-EQ dated May 8, 2018, DEF included an adjustment of approximately $13.20 million system ($13.13 million retail) for amortization of the Florida Power Development, LLC qualifying facility regulatory asset partially offset by a credit of approximately $7.21 million system ($7.21 million retail) related to Crystal River 4 replacement power costs approved in Order No. PSC-2021-0466-FOF-EI. These adjustments are shown on Exhibit No. ___(GPD-3T), in the footnotes to Line 6b on page 1 of 2, Schedule A2, and on line 3, page 1 of 2, Schedule A1.

Q. Did DEF make an adjustment for changes in coal inventory based on an Aerial Survey?

A. Yes. DEF included an adjustment of $4.7 million to coal inventory attributable to the semi-annual aerial surveys conducted on May 4, 2021 and October 26, 2021, in accordance with Order No. PSC-1997-0359-FOF-EI, Docket No.

19970001-EI. This adjustment represents 2.85% of the total coal consumed at the Crystal River facility in 2021.

Q. Did DEF exceed the economy sales threshold in 2021?

A. Yes. DEF did exceed the gain on economy sales threshold of $1.7 million in 2021. As reported on Schedule A1-2, Line 11a, the gain for the year-to-date period through December 2021 was $2.9 million. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gain in excess of the three-year rolling average. For 2021, that amount is approximately $0.2 million.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November 2021 hearings been updated to incorporate actual data for all of year 2021?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2019 through 2021, as follows:

Year	Actual Gain
2019	$ 1,649,136
2020	$ 1,223,709
2021	$ 2,855,389
Three-Year Average	$ 1,909,411

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2021 for capacity cost recovery?

A. The actual ending balance as of December 31, 2021 for true-up purposes is an over-recovery of $6,031,782, as shown on Exhibit No. __(GPD-2T).

Q. How does this amount compare to the estimated 2021 ending balance included in the Company’s Actual/Estimated Filing?

A. When the estimated 2021 over-recovery of $2,718,273 is compared to the $6,031,782 actual over-recovery, the final capacity true-up for the twelve-month period ended December 2021 is an over-recovery of $3,313,509, as shown on Exhibit No. __(GPD-2T).

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes. The calculation of the final net true-up amount follows the procedures established by the Commission.

Q. What factors contributed to the actual period-end capacity over-recovery of $3.3 million?

A. Exhibit No. __ (GPD-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $3.3 million over-recovery is primarily due to lower capacity costs.

OTHER MATTERS

Q. What capital structure and cost rates did DEF rely on to calculate the revenue requirement rate of return for the period January 2021 through December 2021?

A. DEF used the capital structure and cost rates consistent with the language in Order No. PSC-2020-0165-PAA-EU. The capital structure and cost rates relied on to calculate the revenue requirement rate of return for the period January 2021 through December 2021 are shown on Exhibit No. __(GPD-4T).

Q. Does this conclude your direct true-up testimony?

A. Yes.

Duke Energy Florida, LLC
Fuel Adjustment Clause
Summary of Actual True-Up Amount
January 2021 - December 2021

Line No.	Description	Contr bution to Over/(Under) Recovery Period to Date
	KWH Sales:	
1	Jurisdictional kWh Sales - Difference	142,117,132
2	Non-Jurisdictional kWh Sales - Difference	54,994,513
3	Total System kWh Sales - Difference Schedule A2, pg 1 of 2, line B3	197,111,645
	System:	
4	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 2 of 2, line C4	$ 173,018,339
	Jurisdictional:	
5	Fuel Revenues - Difference Schedule A2, page 2 of 2, line C3	4,579,516
6	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 2 of 2, line C6 - C12 - C7	416,992,542
7	True-Up Amount for the Period	(412,413,026)
8	True-Up for the Prior Period Schedule A2, page 2 of 2, line C9	21,579,587
9	True-Up Collected/(Refunded) in Current Period	(21,579,586)
10	Interest Provision Schedule A2, page 2 of 2, line C8	(111,128)
11	Actual True-Up Ending Balance for the Period January 2021 through December 2021 Schedule A2, page 2 of 2, line C13	(412,524,152)
12	Estimated True-Up Ending Balance for the Period January 2021 through December 2021 as approved in Order No. PSC-2022-0061-PCO-EI *	(415,458,323)
13	Total True-Up for the Period January 2021 through December 2021	$ 2,934,170

* Line 12 includes approximately $246.8M approved by the Commission as part of DEF's Rate Mitigation Plan in Order No. PSC-2021-0425-FOF-EI with the remaining balance of approximately $168.7M approved for recovery in DEF's Mid-course Correction Order No. PSC-2022-0061-PCO-EI.

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Witness:	Dean
Exh bit No.	(GPD-1T)
	Sheet 2 of 6

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of Actual True-up
January 2021 - December 2021

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 91,130,395	$ 89,669,082	$ 92,086,502	$ 91,479,028	$ 116,809,348	$ 123,000,789	$ 604,175,144
	2	Fuel Cost of Power Sold	(6,980,349)	(2,343,139)	(2,503,060)	(3,313,839)	(8,802,456)	(8,990,972)	(32,933,814)
	3	Fuel Cost of Purchased Power	1,098,076	3,598,830	12,098,754	5,959,317	10,846,159	13,023,594	46,624,731
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	7,548,154	7,301,243	8,097,325	7,109,630	8,508,302	9,152,559	47,717,214
	4	Energy Cost of Economy Purchases	541,456	928,870	1,048,067	1,424,838	4,071,775	3,333,096	11,348,103
	5	Adjustments to Fuel Cost	1,287,414	1,129,037	1,088,154	1,105,338	1,102,029	3,040,212	8,752,184
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	94,625,147	100,283,924	111,915,742	103,764,312	132,535,158	142,559,279	685,683,562
B	1	Jurisdictional MWH Sales	2,883,090	2,745,686	2,893,187	2,950,824	3,156,780	3,692,154	18,321,719
	2	Non-Jurisdictional MWH Sales	17	15,027	1,840	1,128	1,780	19,330	39,122
	3	TOTAL SALES (Lines B1 + B2)	2,883,105	2,760,713	2,895,026	2,951,953	3,158,561	3,711,484	18,360,842
	4	Jurisdictional % of Total Sales (Line B1/B3)	100.00%	99.46%	99.94%	99.96%	99.94%	99.48%	99.79%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	87,983,471	83,155,269	87,192,862	89,476,925	96,745,142	114,558,977	559,112,646
	2	True-Up Provision	5,090,285	5,090,285	5,090,285	5,090,285	5,090,285	5,090,285	30,541,710
	2a	Incentive Provision	(367,309)	(367,309)	(367,309)	(367,309)	(367,309)	(367,309)	(2,203,856)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	92,706,447	87,878,245	91,915,838	94,199,901	101,468,118	119,281,953	587,450,500
	4	Fuel & Net Power Transactions (Line A6)	94,625,147	100,283,924	111,915,742	103,764,312	132,535,158	142,559,279	685,683,562
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	94,654,481	99,770,319	111,879,910	103,751,849	132,492,725	141,857,680	684,406,963
	6	Over/(Under) Recovery (Line 3 - Line 5)	(1,948,034)	(11,892,074)	(19,964,072)	(9,551,948)	(31,024,607)	(22,575,727)	(96,956,463)
	7	Interest Provision	1,625	545	(1,197)	(2,785)	(3,010)	(4,605)	(9,427)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(1,946,408)	(11,891,529)	(19,965,268)	(9,554,733)	(31,027,617)	(22,580,329)	(96,965,887)
	9	Plus: Prior Period Balance	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587
	10	Plus: Cumulative True-Up Provision	(5,090,285)	(10,180,570)	(15,270,855)	(20,361,139)	(25,451,425)	(30,541,710)	(30,541,710)
	11	Subtotal Prior Period True-up	16,489,302	11,399,017	6,308,732	1,218,448	(3,871,838)	(8,962,122)	(8,962,122)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	14,542,894	(2,438,921)	(27,494,476)	($42,139,494)	($78,257,396)	($105,928,013)	(105,928,013)

Docket No. 20220001-EI
Witness: Dean
Exh bit No. (GPD-1T)
Sheet 3 of 6

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of Actual True-up
January 2021 - December 2021

			JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 148,931,960	$ 165,169,460	$ 158,793,245	$ 185,424,072	$ 156,689,007	$ 146,830,015	$ 1,566,012,904
	2	Fuel Cost of Power Sold	(11,387,686)	(12,767,865)	(14,917,255)	(19,177,440)	(11,072,299)	(10,739,821)	(112,996,180)
	3	Fuel Cost of Purchased Power	10,776,054	14,150,545	15,835,079	15,320,134	2,150,189	5,188,901	110,045,633
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	8,708,077	9,031,911	8,952,041	8,982,700	7,770,730	9,723,679	100,886,353
	4	Energy Cost of Economy Purchases	4,321,612	3,611,096	8,320,941	5,227,466	382,864	1,088,119	34,300,202
	5	Adjustments to Fuel Cost	1,109,677	1,121,003	107,024	1,083,801	(6,133,298)	3,779,665	9,820,056
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	162,459,696	180,316,150	177,091,076	196,860,734	149,787,195	155,870,558	1,708,068,970
B	1	Jurisdictional MWH Sales	3,774,783	3,758,053	4,155,474	3,724,431	2,547,394	3,171,756	39,453,609
	2	Non-Jurisdictional MWH Sales	48,760	95,797	41,053	580	2,538	567	228,418
	3	TOTAL SALES (Lines B1 + B2)	3,823,543	3,853,850	4,196,526	3,725,011	2,549,932	3,172,322	39,682,027
	4	Jurisdictional % of Total Sales (Line B1/B3)	98.72%	97.51%	99.02%	99.98%	99.90%	99.98%	99.42%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	117,399,908	117,267,313	147,489,868	131,011,067	88,131,897	108,553,472	1,268,966,170
	2	True-Up Provision	5,090,285	5,090,285	5,090,285	(8,077,661)	(8,077,661)	(8,077,661)	21,579,586
	2a	Incentive Provision	(367,309)	(367,309)	(367,309)	(367,309)	(367,309)	(367,309)	(4,407,712)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	122,122,884	121,990,289	152,212,844	122,566,097	79,686,927	100,108,502	1,286,138,044
	4	Fuel & Net Power Transactions (Line A6)	162,459,696	180,316,150	177,091,076	196,860,734	149,787,195	155,870,558	1,708,068,972
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	160,425,118	175,875,509	175,404,683	196,876,472	149,679,306	155,883,019	1,698,551,071
	6	Over/(Under) Recovery (Line 3 - Line 5)	(38,302,235)	(53,885,220)	(23,191,838)	(74,310,375)	(69,992,380)	(55,774,517)	(412,413,028)
	7	Interest Provision	(7,657)	(8,941)	(11,123)	(16,183)	(26,705)	(31,092)	(111,128)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(38,309,892)	(53,894,161)	(23,202,961)	(74,326,558)	(70,019,085)	(55,805,609)	(412,524,155)
	9	Plus: Prior Period Balance	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587
	10	Plus: Cumulative True-Up Provision	(35,631,995)	(40,722,281)	(45,812,566)	(37,734,905)	(29,657,245)	(21,579,584)	(21,579,584)
	11	Subtotal Prior Period True-up	(14,052,408)	(19,142,694)	(24,232,979)	(16,155,318)	(8,077,658)	3	3
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($149,328,190)	($208,312,636)	($236,605,883)	($302,854,780)	($364,796,204)	($412,524,152)	(412,524,152)

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of 2021 Actual/Estimated True-up
January 2021 - December 2021 (Filed 12/17/21 - Midcourse Filing)

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 91,130,395	$ 89,669,082	$ 92,086,502	$ 91,479,028	$ 116,809,348	$ 123,000,789	$ 604,175,144
	2	Fuel Cost of Power Sold	(6,980,349)	(2,343,139)	(2,503,060)	(3,313,839)	(8,802,456)	(8,990,972)	(32,933,814)
	3	Fuel Cost of Purchased Power	1,098,076	3,598,830	12,098,754	5,959,317	10,846,159	13,023,594	46,624,731
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	7,548,154	7,301,243	8,097,325	7,109,630	8,508,302	9,152,559	47,717,214
	4	Energy Cost of Economy Purchases	541,456	928,870	1,048,067	1,424,838	4,071,775	3,333,096	11,348,103
	5	Adjustments to Fuel Cost	1,287,414	1,129,037	1,088,154	1,105,338	1,102,029	3,040,212	8,752,184
	6	TOTAL FUEL & NET POWER TRANSACTIONS	94,625,147	100,283,924	111,915,742	103,764,312	132,535,158	142,559,279	685,683,562
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional MWH Sales	2,883,089	2,745,686	2,893,186	2,950,824	3,156,781	3,692,154	18,321,720
	2	Non-Jurisdictional MWH Sales	17	15,027	1,840	1,128	1,780	19,330	39,122
	3	TOTAL SALES (Lines B1 + B2)	2,883,105	2,760,713	2,895,026	2,951,952	3,158,561	3,711,484	18,360,842
	4	Jurisdictional % of Total Sales (Line B1/B3)	100.00%	99.46%	99.94%	99.96%	99.94%	99.48%	99.79%
C	1	Jurisdictional Fuel Recovery Revenue	87,983,471	83,155,269	87,192,862	89,476,925	96,745,142	114,558,977	559,112,646
		(Net of Revenue Taxes)							
	2	True-Up Provision	5,090,285	5,090,285	5,090,285	5,090,285	5,090,285	5,090,285	30,541,710
	2a	Incentive Provision	(367,309)	(367,309)	(367,309)	(367,309)	(367,309)	(367,309)	(2,203,854)
	3	FUEL REVENUE APPLICABLE TO PERIOD	92,706,447	87,878,245	91,915,838	94,199,901	101,468,118	119,281,953	587,450,502
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	94,625,147	100,283,924	111,915,742	103,764,312	132,535,158	142,559,279	685,683,562
	5	Jurisdictional Total Fuel Costs & Net Power Transactions	94,654,481	99,770,319	111,879,910	103,751,849	132,492,725	141,857,680	684,406,963
		(Line A6 * Line B4 * Line Loss Multiplier)							
	6	Over/(Under) Recovery (Line 3 - Line 5)	(1,948,034)	(11,892,074)	(19,964,072)	(9,551,948)	(31,024,607)	(22,575,727)	(96,956,461)
	7	Interest Provision	1,625	545	(1,197)	(2,785)	(3,010)	(4,605)	(9,427)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(1,946,408)	(11,891,529)	(19,965,269)	(9,554,733)	(31,027,617)	(22,580,331)	(96,965,888)
	9	Plus: Prior Period Balance	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587
	10	Plus: Cumulative True-Up Provision	(5,090,285)	(10,180,570)	(15,270,855)	(20,361,140)	(25,451,425)	(30,541,710)	(30,541,710)
	11	Subtotal Prior Period True-up	16,489,302	11,399,017	6,308,732	1,218,447	(3,871,838)	(8,962,123)	(8,962,123)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	$14,542,893	($2,438,921)	($27,494,475)	($42,139,493)	($78,257,395)	($105,928,010)	(105,928,010)

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of 2017 Actual/Estimated True-up
January 2021 - December 2021 (Filed 12/17/21 - Midcourse Filing)

			JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 148,931,960	$ 165,169,460	$ 158,793,245	$ 185,424,072	$ 156,689,007	$ 139,734,801	$ 1,558,917,690
	2	Fuel Cost of Power Sold	(11,387,686)	(12,767,865)	(14,917,255)	(19,177,440)	(11,072,297)	(4,800,356)	(107,056,713)
	3	Fuel Cost of Purchased Power	10,776,054	14,150,545	15,835,079	15,320,134	2,150,189	55,778	104,912,510
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	8,708,077	9,031,911	8,952,041	8,982,700	7,770,730	13,221,196	104,383,869
	4	Energy Cost of Economy Purchases	4,321,612	3,611,096	8,320,941	5,227,466	382,864	390,106	33,602,189
	5	Adjustments to Fuel Cost	1,109,677	1,121,003	107,024	1,083,801	(6,133,298)	1,076,898	7,117,289
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	162,459,696	180,316,150	177,091,076	196,860,734	149,787,195	149,678,423	1,701,876,835
B	1	Jurisdictional MWH Sales	3,774,783	3,758,052	4,155,473	3,724,431	2,547,394	2,830,489	39,112,342
	2	Non-Jurisdictional MWH Sales	48,760	95,797	41,053	580	2,538	1,255	229,105
	3	TOTAL SALES (Lines B1 + B2)	3,823,543	3,853,850	4,196,526	3,725,010	2,549,933	2,831,743	39,341,448
	4	Jurisdictional % of Total Sales (Line B1/B3)	98.72%	97.51%	99.02%	99.98%	99.90%	99.96%	99.42%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	117,399,908	117,267,313	147,489,868	131,011,067	88,131,897	99,396,843	1,259,809,541
	2	True-Up Provision	5,090,285	5,090,285	5,090,285	(8,077,661)	(8,077,661)	(8,077,656)	21,579,592
	2a	Incentive Provision	(367,309)	(367,309)	(367,309)	(367,309)	(367,309)	(367,313)	(4,407,712)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	122,122,884	121,990,289	152,212,844	122,566,097	79,686,927	90,951,874	1,276,981,421
	4	Fuel & Net Power Transactions (Line A6)	162,459,696	180,316,150	177,091,076	196,860,734	149,787,195	149,678,423	1,701,876,835
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	160,425,118	175,875,509	175,404,683	196,876,471	149,679,306	149,660,445	1,692,328,495
	6	Over/(Under) Recovery (Line 3 - Line 5)	(38,302,235)	(53,885,220)	(23,191,838)	(74,310,375)	(69,992,380)	(58,708,570)	(415,347,079)
	7	Interest Provision	(7,657)	(8,941)	(11,123)	(16,183)	(26,705)	(31,206)	(111,242)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(38,309,892)	(53,894,161)	(23,202,961)	(74,326,558)	(70,019,085)	(58,739,776)	(415,458,321)
	9	Plus: Prior Period Balance	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587
	10	Plus: Cumulative True-Up Provision	(35,631,995)	(40,722,280)	(45,812,565)	(37,734,904)	(29,657,243)	(21,579,591)	(21,579,591)
	11	Subtotal Prior Period True-up	(14,052,408)	(19,142,693)	(24,232,978)	(16,155,318)	(8,077,657)	(5)	(5)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($149,328,189)	($208,312,635)	($236,605,881)	($302,854,778)	($364,796,202)	($415,458,323)	(415,458,323)

Duke Energy Florida, LLC
Fuel Adjustment Clause
Fuel and Net Power Cost Variance Analysis
January 2021 - December 2021

	(A) Energy Source	(B) MWH Variances	(C) Heat Rate Variances	(D) Price Variances	(E) Total
1	Heavy Oil	0	0	0	0
2	Light Oil	(1,011,117)	803,741	34,227	(173,149)
3	Coal	(4,007,672)	221,462	(1,646,462)	(5,432,672)
4	Gas	9,619,914	5,792,754	(2,711,633)	12,701,035
5	Nuclear	0	0	0	0
6	Other Fuel	0	0	0	0
7	Total Generation	4,601,126	6,817,957	(4,323,868)	7,095,214
8	Firm Purchases	4,007,813	0	1,125,310	5,133,123
9	Economy Purchases	749,162	0	(51,150)	698,013
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	(1,216,788)	0	(2,280,729)	(3,497,516)
12	Total Purchases	3,540,187	0	(1,206,568)	2,333,619
13	Economy Sales	0	0	0	0
14	Other Power Sales	(2,552,564)	0	7,518	(2,545,046)
15	Supplemental Sales	(4,298,319)	0	903,900	(3,394,420)
16	Total Sales	(6,850,883)	0	911,418	(5,939,465)
17	Total Fuel and Net Power Cost Variance	1,290,430	6,817,957	(4,619,018)	3,489,368

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January 2021 - December 2021

Line No.	Description	Actual	Actual/Estimated	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 35 & Sheet 3 of 3, Line 35	$ 483,783,463	$ 484,578,871	$ (795,408)
2	Capacity Cost Recovery Expenses Sheet 2 of 3, Line 31 & Sheet 3 of 3, Line 31	484,743,860	488,389,201	(3,645,341)
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 38 & Sheet 3 of 3, Line 38	(4,072)	(4,567)	495
4	Sub-Total Current Period Over/(Under) Recovery Sheet 2 of 3, Line 39 & Sheet 3 of 3, Line 39	$ (964,469)	$ (3,814,896)	$ 2,850,427
5	Prior Period True-up - January through December 2020 - Over/(Under) Recovery Sheet 2 of 3, Line 40 & Sheet 3 of 3, Line 40	6,533,167	6,070,083	463,084
6	Prior Period True-up - January through December 2020 - (Refunded)/Collected Sheet 2 of 3, Line 41 & Sheet 3 of 3, Line 41	463,084	463,084	0
7	Actual True-Up Ending Balance Over/(Under) Recovery for the Period January through December 2021 Sheet 2 of 3, Line 43 & Sheet 3 of 3, Line 43	$ 6,031,782	$ 2,718,273	$ 3,313,509
8	Estimated True-Up Ending Balance for the Period Included in the Filing of Levelized Fuel Cost Factors January through December 2022 per Order No. PSC-2021-0442-FOF-EI (Sheet 3 of 3, Line 43)	$2,718,273		
9	Total Over/(Under) Recovery for the Period January through December 2021 (Line 7 - Line 8)	$ 3,313,509		

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Calculation of Actual True-Up
January 2021 - December 2021

		ACT Jan-21	ACT Feb-21	ACT Mar-21	ACT Apr-21	ACT May-21	ACT Jun-21	ACT Jul-21	ACT Aug-21	ACT Sep-21	ACT Oct-21	ACT Nov-21	ACT Dec-21	Total
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	6,181,528	6,196,226	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,094,746	74,172,395
3	Orlando Cogen Limited (ORLACOGL)	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	74,711,198
4	Pasco County Resource Recovery (PASCOUNT)	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	27,412,320
5	Pinellas County Resource Recovery (PINCOUNT)	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	65,253,240
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	101,978,675
7	Subtotal - Base Level Capacity Costs	28,627,814	28,642,512	28,635,163	28,635,163	28,635,163	28,635,163	28,635,163	28,635,163	28,635,163	28,635,163	28,635,163	28,541,033	343,527,827
8	Base Production Jurisdictional Respons bility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
9	Base Level Jurisdictional Capacity Costs	26,590,945	26,604,598	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,510,338	319,085,824
10	**Intermediate Production Level Capacity Costs**													
11	Southern Franklin	4,832,347	4,988,816	2,913,671	2,914,969	3,198,304	(755,104)	0	0	0	0	0	79,292	18,172,295
12	Schedule H Capacity Sales	(5,587)	0	0	0	0	225,736	244,901	0	0	0	72,800	(21,852)	515,997
13	Subtotal - Intermediate Level Capacity Costs	4,826,760	4,988,816	2,913,671	2,914,969	3,198,304	(529,369)	244,901	0	0	0	72,800	57,439	18,688,292
14	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
15	Intermediate Level Jurisdictional Capacity Costs	3,509,199	3,627,019	2,118,327	2,119,270	2,325,263	(384,867)	178,050	0	0	0	52,928	41,760	13,586,948
16	**Peaking Production Level Capacity Costs**													
17	Shady Hills	1,976,940	1,976,940	1,976,940	804,060	1,916,460	3,896,100	4,825,132	2,675,452	597,532	799,264	940,024	1,779,955	24,164,799
18	Vandolah	3,033,279	2,968,686	2,017,074	1,998,157	2,873,617	5,948,748	3,950,401	5,847,436	2,792,890	1,973,594	2,072,642	3,028,955	38,505,479
19	Other	-	-	-	-	-	-	-	-	-	-	-	-	
20	Subtotal - Peaking Level Capacity Costs	5,010,219	4,945,626	3,994,014	2,802,217	4,790,077	9,844,848	8,775,533	8,522,888	3,390,422	2,772,858	3,012,666	4,808,911	62,670,277
21	Peaking Production Jurisdictional Respons bility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
22	Peaking Level Jurisdictional Capacity Costs	4,806,003	4,744,042	3,831,218	2,687,999	4,594,833	9,443,572	8,417,842	8,175,495	3,252,228	2,659,837	2,889,869	4,612,899	60,115,837
23	**Other Capacity Costs**													
24	Retail Wheeling	0	(19,418)	(4,147)	(1,634)	0	0	0	0	0	0	(175,299)	(307,940)	(508,438)
25	Ridge Generating Station L.P. Termination [1]	670,785	667,189	656,848	657,880	654,349	650,819	647,288	643,758	640,228	636,697	633,167	625,726	7,784,734
26	State Corporate Income Tax Change [2]	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(2,793,312)
27	CR1&2 NBV [3]	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	80,592,431
28	Total Other Capacity Costs	7,154,045	7,131,031	7,135,961	7,139,506	7,137,609	7,134,079	7,130,548	7,127,018	7,123,488	7,119,957	6,941,128	6,801,046	85,075,415
29	**Total Capacity Costs (line 9+15+22+28)**	42,060,192	42,106,689	39,683,277	38,544,545	40,655,476	42,790,556	42,324,212	41,900,284	36,973,487	36,377,565	36,481,697	37,966,044	477,864,024
30	**ISFSI Revenue Requirement** [3]	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	6,879,837
31	**Total Recoverable Capacity & ISFSI Costs (line 29+30)**	42,633,512	42,680,009	40,256,597	39,117,864	41,228,795	43,363,876	42,897,531	42,473,604	37,546,807	36,950,885	37,055,017	38,539,363	484,743,860
32	**Capacity Revenues:**													
33	Capacity Cost Recovery Revenues (net of tax)	35,903,840	34,543,316	35,777,609	36,135,702	39,269,964	45,215,250	46,088,175	45,797,326	50,153,126	45,022,522	32,139,196	38,200,521	484,246,547
34	Prior Period True-Up Provision Over/(Under) Recovery	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(463,084)
35	Current Period CCR Revenues (net of tax)	35,865,250	34,504,726	35,739,018	36,097,112	39,231,373	45,176,659	46,049,585	45,758,736	50,114,536	44,983,932	32,100,605	38,161,931	483,783,463
36	**True-Up Provision**													
37	True-Up Provision - Over/(Under) Recov (Line 35-31)	(6,768,262)	(8,175,284)	(4,517,578)	(3,020,753)	(1,997,422)	1,812,785	3,152,052	3,285,132	12,567,729	8,033,047	(4,954,412)	(377,434)	(960,397)
38	Interest Provision for the Month	249	(425)	(883)	(1,181)	(862)	(865)	(886)	(576)	(178)	407	669	459	(4,072)
39	Current Cycle Balance - Over/(Under)	(6,768,013)	(14,943,723)	(19,462,183)	(22,484,118)	(24,482,402)	(22,670,482)	(19,519,316)	(16,234,760)	(3,667,208)	4,366,246	(587,497)	(964,471)	(964,471)
40	Prior Period Balance - Over/(Under) Recovered	6,070,083	6,108,673	6,147,264	6,185,854	6,224,444	6,263,035	6,301,625	6,340,215	6,378,806	6,417,396	6,455,986	6,494,577	6,533,167
41	Prior Period Cumulative True-Up Collected/(Refunded)	38,590	38,590	38,590	38,590	38,590	38,590	38,590	38,590	38,590	38,590	38,590	38,590	463,084
42	Prior Period True-up Balance - Over/(Under)	6,108,673	6,147,264	6,185,854	6,224,444	6,263,035	6,301,625	6,340,215	6,378,806	6,417,396	6,455,986	6,494,577	6,533,167	6,996,251
43	**Net Capacity True-up Over/(Under) (Line 39+42)**	(659,340)	(8,796,459)	(13,276,330)	(16,259,674)	(18,219,367)	(16,368,857)	(13,179,101)	(9,855,954)	2,750,188	10,822,232	5,907,080	5,568,696	6,031,782

[1] Approved in Order No. PSC-2018-0532-PAA-EQ.
[2] Approved in Order No. PSC-2021-0024-FOF-EI.
[3] As set forth in DEF's 2017 Settlement approved in Commission Order No. PSC-2017-0451-AS-EU.

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Calculation of Actual/Estimated True-Up
January 2021 - December 2021 (Filed 9/3/21)

		ACT Jan-21	ACT Feb-21	ACT Mar-21	ACT Apr-21	ACT May-21	ACT Jun-21	ACT Jul-21	EST Aug-21	EST Sep-21	EST Oct-21	EST Nov-21	EST Dec-21	Total
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	6,181,528	6,196,226	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	74,266,524
3	Orlando Cogen Limited (ORLACOGL)	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	74,711,197
4	Pasco County Resource Recovery (PASCOUNT)	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	27,412,320
5	Pinellas County Resource Recovery (PINCOUNT)	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	65,253,240
6	Po k Power Partners, L.P. (MULBERRY/ROYSTER)	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	101,978,673
7	Subtotal - Base Level Capacity Costs	28,627,814	28,642,512	28,635,163	28,635,163	28,635,163	28,635,163	28,635,163	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	343,621,954
8	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
9	Base Level Jurisdictional Capacity Costs	26,590,945	26,604,597	26,597,770	26,597,770	26,597,770	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	319,173,247
10	**Intermediate Production Level Capacity Costs**													
11	Southern Franklin	4,832,347	4,988,816	2,913,671	2,914,969	3,198,304	(755,104)	0	0	0	0	0	0	18,093,003
12	Schedule H Capacity Sales	(5,587)	0	0	0	0	225,736	244,901	0	0	0	0	0	465,050
13	Subtotal - Intermediate Level Capacity Costs	4,826,760	4,988,816	2,913,671	2,914,969	3,198,304	(529,369)	244,901	-	-	-	-	-	18,558,052
14	Intermediate Production Jurisdict. Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
15	Intermediate Level Jurisdict. Capacity Costs	3,509,199	3,627,019	2,118,327	2,119,270	2,325,264	(384,867)	178,050	-	-	-	-	-	13,492,262
16	**Peaking Production Level Capacity Costs**													
17	Shady Hills	1,976,940	1,976,940	1,976,940	804,060	1,916,460	3,896,100	4,825,132	3,901,540	1,820,718	1,370,811	1,370,811	1,978,186	27,814,638
18	Vandolah (NSG)	3,033,279	2,968,686	2,017,074	1,998,157	2,873,617	5,948,748	3,950,401	5,649,696	2,702,911	1,990,514	2,036,254	2,865,669	38,035,006
19	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal - Peaking Level Capacity Costs	5,010,219	4,945,626	3,994,014	2,802,217	4,790,077	9,844,848	8,775,533	9,551,235	4,523,630	3,361,326	3,407,065	4,843,855	65,849,644
21	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
22	Peaking Level Jurisdictional Capacity Costs	4,806,003	4,744,042	3,831,218	2,687,999	4,594,833	9,443,572	8,417,842	9,161,927	4,339,247	3,224,318	3,268,193	4,646,419	63,165,613
23	**Other Capacity Costs**													
24	Retail Wheeling	-	(19,418)	(4,147)	(1,634)	-	-	-	5,793	8,981	24,821	39,349	36,727	90,471
25	Ridge Generating Station L.P. Termination [1]	670,785	667,189	656,848	657,880	654,349	650,819	647,288	643,758	640,228	636,697	633,167	629,636	7,788,644
26	State Corporate Income Tax Change [2]	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(2,793,310)
27	CR1&2 NBV [3]	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	80,592,431
28	Total Other Capacity Costs	7,154,045	7,131,031	7,135,961	7,139,506	7,137,609	7,134,079	7,130,548	7,132,811	7,132,469	7,144,779	7,155,776	7,149,624	85,678,237
29	**Total Capacity Costs (line 9+15+22+28)**	42,060,192	42,106,690	39,683,277	38,544,546	40,655,476	42,790,555	42,324,211	42,892,509	38,069,487	36,966,868	37,021,740	38,393,814	481,509,364
30	**ISFSI Revenue Requirement** [3]	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	6,879,837
31	**Total Recoverable Capacity & ISFSI Costs (line 29+30)**	42,633,512	42,680,009	40,256,596	39,117,865	41,228,796	43,363,875	42,897,531	43,465,829	38,642,807	37,540,187	37,595,060	38,967,133	488,389,201
32	**Capacity Revenues**													
33	Capacity Cost Recovery Revenues (net of tax)	35,903,840	34,543,316	35,777,609	36,135,702	39,269,964	45,215,250	46,088,175	48,407,053	47,602,322	44,377,097	36,846,812	34,874,816	485,041,956
34	Prior Period True-Up Provision Over/(Under) Recovery	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(463,084)
35	**Current Period Revenues (net of tax)**	35,865,250	34,504,726	35,739,018	36,097,112	39,231,373	45,176,659	46,049,585	48,368,462	47,563,732	44,338,507	36,808,222	34,836,226	484,578,871
36	**True-Up Provision**													
37	True-Up Provision - Over/(Under) Recov (Line 35-31)	(6,768,262)	(8,175,284)	(4,517,578)	(3,020,753)	(1,997,422)	1,812,785	3,152,054	4,902,633	8,920,925	6,798,319	(786,838)	(4,130,908)	(3,810,329)
38	Interest Provision for the Month	249	(425)	(883)	(1,181)	(862)	(865)	(886)	(247)	22	227	204	82	(4,567)
39	Current Cycle Balance - Over/(Under)	(6,768,012)	(14,943,722)	(19,462,182)	(22,484,117)	(24,482,400)	(22,670,480)	(19,519,312)	(14,616,927)	(5,695,981)	1,102,563	315,930	(3,814,896)	(3,814,896)
40	Prior Period Balance - Over/(Under) Recovered	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083
41	Prior Period Cumulative True-Up Collected/(Refunded)	38,590	77,181	115,771	154,361	192,952	231,542	270,133	308,723	347,313	385,904	424,494	463,084	463,084
42	Prior Period True-up Balance - Over/(Under)	6,108,673	6,147,264	6,185,854	6,224,445	6,263,035	6,301,625	6,340,216	6,378,806	6,417,396	6,455,987	6,494,577	6,533,167	6,533,167
43	**Net Capacity True-up Over/(Under) (Line 39+42)**	($659,339)	($8,796,458)	($13,276,329)	($16,259,673)	($18,219,367)	($16,368,857)	($13,179,100)	($8,238,121)	$721,416	$7,558,552	$6,810,509	$2,718,273	$2,718,273

[1] Approved in Order No. PSC-2018-0532-PAA-EQ.

[2] Approved in Order No. PSC-2021-0024-FOF-EI.

[3] As set forth in DEF's 2017 Settlement approved in Commission Order No. PSC-2017-0451-AS-EU.

DUKE ENERGY FLORIDA, LLC
FUEL AND PURCHASED POWER
DECEMBER 2021

SCHEDULE A1
PAGE 1 OF 2

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	146,830,015	111,023,612	35,806,403	32.3	3,029,903	2,942,579	87,324	3.0	4.8460	3.7730	1.0730	28.4
2	COAL CAR SALE	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	3,779,665	1,076,898	2,702,767	251.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	TOTAL COST OF GENERATED POWER	150,609,680	112,100,510	38,509,170	34.4	3,029,903	2,942,579	87,324	3.0	4.9708	3.8096	1.1612	30.5
5	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	5,188,901	55,385	5,133,516	9,268.8	60,319	140	60,179	42,985.0	8.6024	39.5607	(30.9583)	(78.3)
6	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	-	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
7	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	1,088,119	377,939	710,180	187.9	21,173	8,432	12,741	151.1	5.1391	4.4822	0.6569	14.7
8	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	9,723,679	10,234,007	(510,327)	(5.0)	212,571	237,161	(24,590)	(10.4)	4.5743	4.3152	0.2591	6.0
9	TOTAL COST OF PURCHASED POWER	16,000,699	10,667,331	5,333,369	50.0	294,064	245,733	48,331	19.7	5.4412	4.3410	1.1002	25.3
10	TOTAL AVAILABLE MWH					3,323,967	3,188,312	135,655	4.3				
11	FUEL COST OF OTHER POWER SALES (SCH A6)	(2,267,017)	(582,137)	(1,684,880)	289.4	(87,843)	(16,991)	(70,852)	417.0	2.5808	3.4262	(0.8454)	(24.7)
11a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(969,071)	(157,770)	(811,301)	514.2	(87,843)	(16,991)	(70,852)	417.0	1.1032	0.9286	0.1746	18.8
11b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	193,814	0	193,814	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
12	FUEL COST OF STRATIFIED SALES	(7,697,548)	(3,208,952)	(4,488,596)	139.9	(217,209)	(86,231)	(130,978)	151.9	3.5438	3.7213	(0.1775)	(4.8)
13	TOTAL FUEL COST AND GAINS ON POWER SALES	(10,739,821)	(3,948,859)	(6,790,963)	172.0	(305,052)	(103,222)	(201,830)	195.5	3.5207	3.8256	(0.3049)	(8.0)
14	NET INADVERTENT AND WHEELED INTERCHANGE					13,936	0	13,936					
15	TOTAL FUEL AND NET POWER TRANSACTIONS	155,870,558	118,818,982	37,051,576	31.2	3,032,851	3,085,089	(52,239)	(1.7)	5.1394	3.8514	1.2880	33.4
16	NET UNBILLED	(28,984,244)	2,903,637	(31,887,881)	(1,098.2)	563,961	(75,392)	639,353	(848.0)	(0.9137)	0.1025	(1.0162)	(991.4)
17	COMPANY USE	744,705	579,884	164,821	28.4	(14,490)	(15,056)	566	(3.8)	0.0235	0.0205	0.0030	14.6
18	T & D LOSSES	21,071,509	6,273,841	14,797,668	235.9	(409,999)	(162,898)	(247,101)	151.7	0.6642	0.2216	0.4426	199.7
19	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	155,870,558	118,818,982	37,051,576	31.2	3,172,322	2,831,743	340,579	12.0	4.9135	4.1960	0.7175	17.1
20	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(31,174)	(47,528)	16,353	(34.4)	(567)	(1,255)	688	(54.8)	5.4987	3.7886	1.7101	45.1
21	JURISDICTIONAL KWH SALES	155,839,384	118,771,454	37,067,930	31.2	3,171,756	2,830,489	341,267	12.1	4.9133	4.1961	0.7172	17.1
22	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00028	155,883,019	118,804,710	37,078,309	31.2	3,171,756	2,830,489	341,267	12.1	4.9147	4.1973	0.7174	17.1
23	PRIOR PERIOD TRUE-UP	8,077,661	8,077,661	(0)	0.0	3,171,756	2,830,489	341,267	12.1	0.2547	0.2854	(0.0307)	(10.8)
24	TOTAL JURISDICTIONAL FUEL COST	163,960,680	126,882,371	37,078,308	29.2	3,171,756	2,830,489	341,267	12.1	5.1694	4.4827	0.6867	15.3
25	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
26	FUEL COST ADJUSTED FOR TAXES									5.1731	4.4859	0.6872	15.3
27	GPIF	367,309	367,309			3,171,756	2,830,489			0.0116	0.0130	(0.0014)	(10.8)
28	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									5.185	4.499	0.686	15.2

*Line 15a. MWH Data for Infomational Purposes Only

Note: Schedules A1/A2 have been updated from the versions filed on January 20, 2022 to reflect the True-Up WACC as prescribed in Order No. PSC-2020-0165-PAA-EU.

DUKE ENERGY FLORIDA, LLC
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
YEAR TO DATE - DECEMBER 2021

SCHEDULE A1
PAGE 2 OF 2

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	1,566,012,904	1,404,339,921	161,672,983	11.5	40,562,710	40,465,354	97,355	0.2	3.8607	3.4705	0.3902	11.2
2	COAL CAR SALE	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	9,820,056	15,303,717	(5,483,661)	(35.8)	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	TOTAL COST OF GENERATED POWER	1,575,832,960	1,419,643,639	156,189,322	11.0	40,562,710	40,465,354	97,355	0.2	3.8849	3.5083	0.3766	10.7
5	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	110,045,633	75,611,032	34,434,601	45.5	1,635,009	1,209,413	425,597	35.2	6.7306	6.2519	0.4787	7.7
6	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
7	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	34,300,202	18,592,667	15,707,535	84.5	638,193	374,636	263,558	70.4	5.3746	4.9629	0.4117	8.3
8	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	100,886,353	106,418,835	(5,532,483)	(5.2)	2,413,486	2,541,596	(128,110)	(5.0)	4.1801	4.1871	(0.0070)	(0.2)
9	TOTAL COST OF PURCHASED POWER	245,232,188	200,622,535	44,609,654	22.2	4,686,689	4,125,644	561,044	13.6	5.2325	4.8628	0.3697	7.6
10	TOTAL AVAILABLE MWH					45,249,398	44,590,999	658,400	1.5				
11	FUEL COST OF OTHER POWER SALES (SCH A6)	(10,417,360)	(5,750,637)	(4,666,723)	81.2	(400,762)	(231,178)	(169,584)	73.4	2.5994	2.4875	0.1119	4.5
11a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(2,855,389)	(1,351,382)	(1,504,007)	111.3	(400,762)	(231,178)	(169,584)	73.4	0.7125	0.5846	0.1279	21.9
11b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	228,227	0	228,227	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
12	FUEL COST OF STRATIFIED SALES	(99,951,656)	(78,113,524)	(21,838,132)	28.0	(3,073,252)	(2,623,343)	(449,909)	17.2	3.2523	2.9776	0.2747	9.2
13	TOTAL FUEL COST AND GAINS ON POWER SALES	(112,996,178)	(85,215,543)	(27,780,636)	32.6	(3,474,014)	(2,854,520)	(619,494)	21.7	3.2526	2.9853	0.2673	9.0
14	NET INADVERTENT AND WHEELED INTERCHANGE					215,318	128,396	86,922					
15	TOTAL FUEL AND NET POWER TRANSACTIONS	1,708,068,970	1,535,050,631	173,018,339	11.3	41,990,702	41,864,874	125,828	0.3	4.0677	3.6667	0.4010	10.9
16	NET UNBILLED	(41,676,247)	(6,433,472)	(35,242,775)	547.8	748,570	178,182	570,388	320.1	(0.1050)	(0.0163)	(0.0887)	544.2
17	COMPANY USE	6,503,505	5,960,634	542,871	9.1	(160,656)	(162,168)	1,513	(0.9)	0.0164	0.0151	0.0013	8.6
18	T & D LOSSES	118,584,121	87,015,406	31,568,715	36.3	(2,896,589)	(2,395,973)	(500,617)	20.9	0.2988	0.2204	0.0784	35.6
19	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	1,708,068,970	1,535,050,631	173,018,339	11.3	39,682,028	39,484,915	197,112	0.5	4.3044	3.8877	0.4167	10.7
20	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(9,996,200)	(7,165,703)	(2,830,497)	39.5	(228,418)	(173,423)	(54,995)	31.7	4.3763	4.1319	0.2444	5.9
21	JURISDICTIONAL KWH SALES	1,698,072,770	1,527,884,928	170,187,842	11.1	39,453,610	39,311,492	142,118	0.4	4.3040	3.8866	0.4174	10.7
22	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00028	1,698,551,069	1,528,315,574	170,235,495	11.1	39,453,610	39,311,492	142,118	0.4	4.3052	3.8877	0.4175	10.7
23	PRIOR PERIOD TRUE-UP	(21,579,586)	(21,579,582)	(4)	0.0	39,453,610	39,311,492	142,118	0.4	(0.0547)	(0.0549)	0.0002	(0.4)
24	TOTAL JURISDICTIONAL FUEL COST	1,676,971,483	1,506,735,992	170,235,491	11.3	39,453,610	39,311,492	142,118	0.4	4.2505	3.8328	0.4177	10.9
25	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
26	FUEL COST ADJUSTED FOR TAXES									4.2536	3.8356	0.4180	10.9
27	GPIF	4,407,712	4,407,708			39,453,610	39,311,492			0.0112	0.0112	0.0000	100.0
28	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									4.265	3.847	0.418	10.9

*Line 15a. MWH Data for Infomational Purposes Only

Note: Schedules A1/A2 have been updated from the versions filed on January 20, 2022 to reflect the True-Up WACC as prescribed in Order No. PSC-2020-0165-PAA-EU.

DUKE ENERGY FLORIDA, LLC
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2021

SCHEDULE A2
PAGE 1 OF 2

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
A .	FUEL COSTS AND NET POWER TRANSACTIONS								
1 .	FUEL COST OF SYSTEM NET GENERATION	$146,830,015	111,023,612	$35,806,403	32.3	$1,566,012,904	$1,404,339,921	$161,672,983	11.5
1a.	COAL CAR SALE	-	0	0	0.0	0	0	0	0.0
2 .	FUEL COST OF POWER SOLD	(2,267,017)	(582,137)	(1,684,880)	289.4	(10,417,360)	(5,750,637)	(4,666,723)	81.2
2a.	GAIN ON POWER SALES	(775,257)	(157,770)	(617,487)	391.4	(2,627,162)	(1,351,382)	(1,275,780)	94.4
3 .	FUEL COST OF PURCHASED POWER	5,188,901	55,385	5,133,516	9,268.8	110,045,633	75,611,032	34,434,601	45.5
3a.	ENERGY PAYMENTS TO QUALIFYING FACILITIES	9,723,679	10,234,007	(510,327)	(5.0)	100,886,353	106,418,835	(5,532,483)	(5.2)
4 .	ENERGY COST OF ECONOMY PURCHASES	1,088,119	377,939	710,180	187.9	34,300,202	18,592,667	15,707,535	84.5
5 .	TOTAL FUEL & NET POWER TRANSACTIONS	159,788,441	120,951,036	38,837,405	32.1	1,798,200,570	1,597,860,438	200,340,133	12.5
6 .	ADJUSTMENTS TO FUEL COST:								
6a.	FUEL COST OF STRATIFIED SALES	(7,697,548)	(3,208,952)	(4,488,596)	139.9	(99,951,656)	(78,113,524)	(21,838,132)	28.0
6b.	OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	3,779,665	1,076,898	2,702,767	251.0	9,820,056	15,303,717	(5,483,661)	(35.8)
6c.	OTHER - PRIOR PERIOD ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
7 .	ADJUSTED TOTAL FUEL & NET PWR TRNS	$155,870,558	$118,818,982	$37,051,576	31.2	$1,708,068,970	$1,535,050,631	$173,018,339	11.3

FOOTNOTE: DETAIL OF LINE 6b ABOVE

N/A - Not used	$0	$0	$0	$0	$0	$0
N/A - Not used	0	0	0	0	0	0
UNIVERSITY OF FLORIDA STEAM REVENUE ALLOCATION {Wholesale Portion}	20	0	20	6,110	0	6,110
WHOLESALE ALLOCATION ADJUSTMENT	0	0	0	0	0	0
TANK BOTTOM ADJUSTMENT	0	0	0	(991,828)	0	(991,828)
AERIAL SURVEY ADJUSTMENT (Coal Pile)	2,723,275	0	2,723,275	4,659,470	0	4,659,470
FPD AGREEMENT TERMINATION	1,056,369	0	1,056,369	13,199,402	0	13,199,402
RAIL CAR SALE PROCEEDS	0	0	0	0	0	0
CITRUS SETTLEMENT FUEL GIVEBACK	0	0	0	0	0	0
NET METER SETTLEMENT	0	0	0	161,397	0	161,397
CR4 OUTAGE REPLACEMENT POWER **	0	0	0	(7,214,495)	0	(7,214,495)
Derivative Collateral Interest	0	0	0	0	0	0
SUBTOTAL LINE 6b SHOWN ABOVE	$3,779,665	$0	$3,779,665	$9,820,056	$0	$9,820,056

** Represents $7,207,280.38 retail as approved at 12/7/2021 Commission agenda grossed up by 99.90% November jurisdictional factor.

		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
B.	KWH SALES								
1 .	JURISDICTIONAL SALES	3,171,755,628	2,830,488,729	341,266,899	12.1	39,453,609,202	39,311,492,069	142,117,132	0.4
2 .	NON JURISDICTIONAL (WHOLESALE) SALES	566,941	1,254,500	(687,559)	(54.8)	228,417,639	173,423,126	54,994,513	31.7
3 .	TOTAL SALES	3,172,322,569	2,831,743,229	340,579,340	12.0	39,682,026,841	39,484,915,195	197,111,645	0.5
4 .	JURISDICTIONAL SALES % OF TOTAL SALES	99.98	99.96	0.02	0.0	99.42	99.56	(0.14)	(0.1)

Note: Schedules A1/A2 have been updated from the versions filed on January 20, 2022 to reflect the True-Up WACC as prescribed in Order No. PSC-2020-0165-PAA-EU.

SCHEDULE A2
PAGE 2 OF 2

DUKE ENERGY FLORIDA, LLC
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2021

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
C.	TRUE UP CALCULATION								
1 .	JURISDICTIONAL FUEL REVENUE	$108,553,472	$99,396,843	$9,156,629	9.2	$1,268,966,170	$1,264,386,654	$4,579,516	0.4
2 .	ADJUSTMENTS:	0	0	0	0.0	0	0	0	0.0
2a.	TRUE UP PROVISION	(8,077,661)	(8,077,661)	0	0.0	21,579,586	21,579,582	4	0.0
2b.	INCENTIVE PROVISION	(367,309)	(367,309)	(0)	0.0	(4,407,712)	(4,407,708)	(4)	0.0
3 .	TOTAL JURISDICTIONAL FUEL REVENUE	100,108,502	90,951,873	9,156,629	10.1	1,286,138,044	1,281,558,528	4,579,516	0.4
4 .	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	155,870,558	118,818,982	37,051,576	31.2	1,708,068,970	1,535,050,631	173,018,339	11.3
5 .	JURISDICTIONAL SALES % OF TOT SALES (LINE B4)	99.98	99.96	0.02	0.0	99.42	99.56	(0.14)	(0.1)
6 .	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS								
	(LINE C4 * LINE C5 * 1.00028 LOSS MULTIPLIER)	155,883,019	118,804,710	37,078,309	31.2	1,698,551,069	1,528,315,574	170,235,495	11.1
7 .	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER)								
	COLLECTION (LINE C3 - C6)	(55,774,517)	(27,852,837)	(27,921,680)	100.3	(412,413,026)	(246,757,047)	(165,655,979)	67.1
8 .	INTEREST PROVISION FOR THE MONTH (LINE D10)	(31,092)	(14,214)	(16,878)	118.7	(111,128)	(80,529)	(30,599)	38.0
9 .	TRUE UP & INTEREST PROVISION BEG OF MONTH/PERIOD	(364,796,204)	(227,048,182)	(137,748,023)	60.7	21,579,587	21,579,587	0	0.0
10.	TRUE UP COLLECTED (REFUNDED)	8,077,661	8,077,661	(0)	0.0	(21,579,586)	(21,579,582)	(4)	0.0
11.	END OF PERIOD TOTAL NET TRUE UP (LINES C7 + C8 + C9 + C10)	(412,524,152)	(246,837,571)	(165,686,581)	67.1	(412,524,152)	(246,837,571)	(165,686,581)	67.1
12.	OTHER:	0				0		0	
13.	END OF PERIOD TOTAL NET TRUE UP (LINES C11 + C12)	($412,524,152)	(246,837,571)	(165,686,581)	67.1	($412,524,152)	(246,837,571)	(165,686,581)	67.1

		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
D.	INTEREST PROVISION				
1 .	BEGINNING TRUE UP (LINE C9)	($364,796,204)	N/A	--	--
2 .	ENDING TRUE UP (LINES C7 + C9 + C10 + C12)	(412,493,061)	N/A	--	--
3 .	TOTAL OF BEGINNING & ENDING TRUE UP	(777,289,265)	N/A	--	--
4 .	AVERAGE TRUE UP (50% OF LINE D3)	(388,644,633)	N/A	--	--
5 .	INTEREST RATE - FIRST DAY OF REPORTING MONTH	0.110	N/A	--	--
6 .	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	0.080	N/A	--	--
7 .	TOTAL (LINE D5 + LINE D6)	0.190	N/A		
8 .	AVERAGE INTEREST RATE (50% OF LINE D7)	0.095	N/A	--	--
9 .	MONTHLY AVERAGE INTEREST RATE (LINE D8/12)	0.008	N/A	--	--
10.	INTEREST PROVISION (LINE D4 * LINE D9)	($31,092)	N/A	--	--

Note: Schedules A1/A2 have been updated from the versions filed on January 20, 2022 to reflect the True-Up WACC as prescribed in Order No. PSC-2020-0165-PAA-EU.

A-3 Generating System Comparative Data Report

Duke Energy Florida, LLC

Docket No. 20220001-EI
Witness: Dean
Exhibit No. (GPD-3T)
Schedule: A3-1
Sheet 5 of 9

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)				
1 - HEAVY OIL	0	0	0	0.0 %
2 - LIGHT OIL	22,218,993	22,392,143	(173,149)	(0.8 %)
3 - COAL	163,564,338	168,997,010	(5,432,672)	(3.2 %)
4 - GAS	1,380,229,573	1,367,528,537	12,701,035	0.9 %
5 - NUCLEAR	0	0	0	0.0 %
6	0	0	0	0.0 %
7	0	0	0	0.0 %
8 - TOTAL ($)	1,566,012,904	1,558,917,690	7,095,214	0.5 %
SYSTEM NET GENERATION (MWH)				
9 - HEAVY OIL	0	0	0	0.0 %
10 - LIGHT OIL	61,413	64,317	(2,904)	(4.5 %)
11 - COAL	5,042,303	5,164,783	(122,480)	(2.4 %)
12 - GAS	34,517,463	34,276,345	241,118	0.7 %
13 - NUCLEAR	0	0	0	0.0 %
14 - SOLAR	941,532	959,919	(18,387)	(1.9 %)
15	0	0	0	0.0 %
16 - TOTAL (MWH)	40,562,710	40,465,364	97,347	0.2 %
UNITS OF FUEL BURNED				
17 - HEAVY OIL (BBL)	0	0	0	0.0 %
18 - LIGHT OIL (BBL)	191,038	192,683	(1,645)	(0.9 %)
19 - COAL (TON)	2,389,754	2,444,014	(54,260)	(2.2 %)
20 - GAS (MCF)	255,328,667	252,875,368	2,453,299	1.0 %
21 - NUCLEAR (MMBTU)	0	0	0	0.0 %
22	0	0	0	0.0 %
23	0	0	0	0.0 %
BTUS BURNED (MILLION BTU)				
24 - HEAVY OIL	0	0	0	0.0 %
25 - LIGHT OIL	1,096,030	1,106,276	(10,245)	(0.9 %)
26 - COAL	53,903,967	55,139,309	(1,235,341)	(2.2 %)
27 - GAS	261,612,956	258,697,319	2,915,636	1.1 %
28 - NUCLEAR	0	0	0	0.0 %
29	0	0	0	0.0 %
30	0	0	0	0.0 %
31 - TOTAL (MILLION BTU)	316,612,953	314,942,903	1,670,050	0.5 %

Note: Schedule A3 has been updated from the version filed on January 20, 2022 to reflect DEF's Midcourse filing approved in Order No. PSC-2022-0061-PCO-EI

A-3 Generating System Comparative Data Report

Duke Energy Florida, LLC

Docket No. 20220001-EI
Witness: Dean
Exhibit No. (GPD-3T)
Schedule: A3-1

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATION MIX (% MWH)				
32 - HEAVY OIL	0.0	0.0	0.0	0.0 %
33 - LIGHT OIL	0.2	0.2	(0.0)	(4.8 %)
34 - COAL	12.4	12.8	(0.3)	(2.6 %)
35 - GAS	85.1	84.7	0.4	0.5 %
36 - NUCLEAR	0.0	0.0	0.0	0.0 %
37 - SOLAR	2.3	2.4	(0.1)	(2.1 %)
38	0	0	0	0.0 %
39 - TOTAL (% MWH)	100	100	0.0	0.0 %
FUEL COST PER UNIT ($)				
40 - HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.0 %
41 - LIGHT OIL ($/BBL)	116.31	116.21	0.09	0.1 %
42 - COAL ($/TON)	68.44	69.15	(0.70)	(1.0 %)
43 - GAS ($/MCF)	5.41	5.41	(0.00)	(0.0 %)
44 - NUCLEAR ($/MBTU)	0.00	0.00	0.00	0.0 %
45	0.00	0.00	0.00	0.0 %
46	0.00	0.00	0.00	0.0 %
FUEL COST PER MILLION BTU ($/MILLION BTU)				
47 - HEAVY OIL	0.00	0.00	0.00	0.0 %
48 - LIGHT OIL	20.27	20.24	0.03	0.2 %
49 - COAL	3.03	3.07	(0.03)	(1.0 %)
50 - GAS	5.28	5.29	(0.01)	(0.2 %)
51 - NUCLEAR	0.00	0.00	0.00	0.0 %
52	0.00	0.00	0.00	0.0 %
53	0.00	0.00	0.00	0.0 %
54 - SYSTEM ($/MBTU)	4.95	4.95	(0.00)	(0.1 %)
BTU BURNED PER KWH (BTU/KWH)				
55 - HEAVY OIL	0	0	0	0.0 %
56 - LIGHT OIL	17,847	17,200	647	3.8 %
57 - COAL	10,690	10,676	14	0.1 %
58 - GAS	7,579	7,547	32	0.4 %
59 - NUCLEAR	0	0	0	0.0 %
60	0	0	0	0.0 %
61	0	0	0	0.0 %
62 - SYSTEM (BTU/KWH)	7,806	7,783	22	0.3 %

Note: Schedule A3 has been updated from the version filed on January 20, 2022 to reflect DEF's Midcourse filing approved in Order No. PSC-2022-0061-PCO-EI

A-3 Generating System Comparative Data Report

Duke Energy Florida, LLC

Docket No.	20220001-EI
Witness:	Dean
Exhibit No.	(GPD-3T)
Schedule:	A3-1
	Sheet 7 of 9

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATED FUEL COST PER KWH (CENTS/KWH)				
63 - HEAVY OIL	0.00	0.00	0.00	0.0 %
64 - LIGHT OIL	36.18	34.82	1.36	3.9 %
65 - COAL	3.24	3.27	(0.03)	(0.9 %)
66 - GAS	4.00	3.99	0.01	0.2 %
67 - NUCLEAR	0.00	0.00	0.00	0.0 %
68	0.00	0.00	0.00	0.0 %
69	0.00	0.00	0.00	0.0 %
70 - SYSTEM (CENTS/KWH)	3.86	3.85	0.01	0.2 %

Note: Schedule A3 has been updated from the version filed on January 20, 2022 to reflect DEF's Midcourse filing approved in Order No. PSC-2022-0061-PCO-EI

Duke Energy Florida, LLC
Schedule A6
Power Sold for the Month of
December 2021

Docket No. 20220001-EI
Witness: Dean
Exhibit No. (GPD-3T)
Schedule A6

(1) Sold To	(2) Type & Schedule	(3) Total KWH Sold (000)	(4) KWH Wheeled from Other Systems (000)	(5) KWH from Own Generation (000)	(6a) Fuel Cost C/KWH	(6b) Total Cost C/KWH	(7) Fuel Adj Total $	(8) Total Cost $	(9) Gain on Sales $
ESTIMATED		9,467		9,467	4.340	5.480	410,860	518,820	107,960
ACTUAL									
Exelon Generation Company, LLC	InternationalSwapsDe	13,480		13,480	2.741	3.811	369,465.81	513,718.56	144,252.75
Florida Municipal Power Agency	CR-1	3,275		3,275	2.757	3.851	90,285.50	126,136.00	35,850.50
Macquarie Energy LLC		11,446		11,446	2.627	3.758	300,690.27	430,093.00	129,402.73
Orlando Utilities Commission	Schedule OS	600		600	3.798	5.032	22,786.78	30,192.30	7,405.52
PJM Settlements, Inc	MR1	8,959		8,959	2.487	3.528	222,783.98	316,047.71	93,263.73
Rainbow Energy Marketing Corporation		696		696	2.753	4.475	19,162.88	31,145.32	11,982.44
Reedy Creek Improvement District	CR-1	8,995		8,995	2.227	2.889	200,315.05	259,840.30	59,525.25
Southern Company Services, Inc.	EEI	15,342		15,342	2.993	4.793	459,121.97	735,316.65	276,194.68
The Energy Authority	Schedule OS	25,050		25,050	2.325	3.138	582,405.00	786,024.00	203,619.00
Adjustments									
Macquarie Energy LLC								15.64	15.64
Tennessee Valley Authority								1,900.16	1,900.16
PJM Settlements								6,167.66	6,167.66
Macquarie Energy LLC								(509.42)	(509.42)
Subtotal - Gain on Other Power Sales		87,843		87,843	2.581	3.684	2,267,017.24	3,236,087.88	969,070.64
CURRENT MONTH TOTAL		87,843		87,843	2.581	3.684	2,267,017.24	3,236,087.88	969,070.64
DIFFERENCE		78,376		78,376	(1.759)	(1.797)	1,856,157	2,717,268	861,111
DIFFERENCE %		827.92		827.92	(40.54)	(32.78)	451.77	523.74	797.62
CUMULATIVE ACTUAL		400,762		400,762	2.599	3.312	10,417,360.08	13,272,749.00	2,855,388.92
CUMULATIVE ESTIMATED		322,386		322,386	2.656	3.274	8,561,203	10,555,481	1,994,278
DIFFERENCE		78,376		78,376	(0.056)	0.038	1,856,157	2,717,268	861,111
DIFFERENCE %		24.31		24.31	(2.12)	1.15	21.68	25.74	43.18

Note: Schedule A6 has been updated from the version filed on January 20, 2022 to reflect DEF's Midcourse filing approved in Order No. PSC-2022-0061-PCO-EI

Duke Energy Florida, LLC
Schedule A12 - Capacity Costs
For the Period January - December 2021

Docket No. 20220001-EI
Witness: Dean
Exh bit No. (GPD-3T)
Schedule A12

	Counterparty	Type	MW	Start Date - End Date	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
1	Orange Cogen (ORANGECO)	QF	74.00	7/1/95 - 12/31/24	6,181,528	6,196,226	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,094,746	74,172,395
2	Orlando Cogen Limited (ORLACOGL)	QF	79.20	9/1/93 - 12/31/23	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	74,711,198
3	Pasco County Resource Recovery (PASCOUNT)	QF	23.00	1/1/95 - 12/31/24	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	27,412,320
4	Pinellas County Resource Recovery (PINCOUNT)	QF	54.75	1/1/95 - 12/31/24	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	65,253,240
5	Polk Power Partners, L.P. (MULBERRY)	QF	115.00	8/1/94 - 8/8/24	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	101,978,675
6	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	QF	39.60	8/1/94 - 1/31/19	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Southern purchase - Franklin	PPA	425	6/1/16 - 5/31/21	4,832,347	4,988,816	2,913,671	2,914,969	3,198,304	(755,104)	0	0	0	0	0	79,292	18,172,295
8	Retail Wheeling				0	(19,418)	(4,147)	(1,634)	0	0	0	0	0	0	(175,299)	(307,940)	(508,438)
9	CR1&2 NBV				6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	80,592,431
10	ISFSI Return				573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	6,879,837
11	Vandolah Capacity Purchase	PPA	669	June 2012 - May 2027	3,033,279	2,968,686	2,017,074	1,998,157	2,873,617	5,948,748	3,950,401	5,847,436	2,792,890	1,973,594	2,072,642	3,028,955	38,505,479
12	Capacity Sales and Purchases	Other		on-going no term date	(5,587)	0	0	0	0	225,736	244,901	0	0	0	72,800	(21,852)	515,997
13	Shady Hills Tolling	PPA	517	4/1/07-4/30/24	1,976,940	1,976,940	1,976,940	804,060	1,916,460	3,896,100	4,825,132	2,675,452	597,532	799,264	940,024	1,779,955	24,164,799
14	RidgeGen Agreement Termination				670,785	667,189	656,848	657,880	654,349	650,819	647,288	643,758	640,228	636,697	633,167	625,726	7,784,734
15	Hamilton SoBRA True-Up				0	0	0	0	0	0	0	0	0	0	0	0	0
16	Columbia SoBRA True-Up				0	0	0	0	0	0	0	0	0	0	0	0	0
17	Lake Placid SoBRA True-Up				0	0	0	0	0	0	0	0	0	0	0	0	0
18	Trenton SoBRA True-Up				0	0	0	0	0	0	0	0	0	0	0	0	0
19	Debary SoBRA True-Up				0	0	0	0	0	0	0	0	0	0	0	0	0
20	State Corporate Income Tax Change				(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(2,793,312)
	TOTAL				46,192,158	46,281,305	43,252,129	42,065,174	44,334,473	45,658,041	45,359,465	44,858,388	39,722,392	39,101,298	39,235,077	40,781,749	516,841,648

Note: Schedule A12 has been updated from the version filed on January 20, 2022 to reflect the True-Up WACC as prescribed in Order No. PSC-2020-0165-PAA-EU.

Docket No. 20220001-EI
Witness: Dean
Exhibit No. (GPD-4T)
Shhet 1 of 1

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Capital Structure and Cost Rates Applied to Capital Projects
Actual Capital Structure and Cost Rates

		(1) Jurisdictional Rate Base Adjusted Retail ($000s)	(2) Cap Ratio	(3) Cost Rate	(4) Weighted Cost	(5) Revenue Requirement Rate	(6) Monthly Revenue Requirement Rate
1	Common Equity	$ 6,688,612	43.79%	10.50%	4.60%	6.04%	0.5033%
2	Long Term Debt	5,674,817	37.16%	4.31%	1.60%	1.60%	0.1333%
3	Short Term Debt	260,772	1.71%	0.16%	0.00%	0.00%	0.0000%
4	Cust Dep Active	178,995	1.17%	2.65%	0.03%	0.03%	0.0025%
5	Cust Dep Inactive	1,625	0.01%		0.00%	0.00%	0.0000%
6	Invest Tax Cr	165,584	1.08%	7.66%	0.08%	0.10%	0.0083%
7	Deferred Inc Tax	2,302,312	15.07%		0.00%	0.00%	0.0000%
8	**Total**	**$ 15,272,718**	**100.00%**		**6.31%**	**7.77%**	**0.6475%**

	ITC split between Debt and Equity**:		Ratio	Cost Rate	Ratio	Ratio	Deferred Inc Tax	Weighted ITC	After Gross-up
9	Common Equity	6,688,612	54%	10.5%	5.68%	74.2%	0.08%	0.0593%	0.078%
10	Preferred Equity	-	0%				0.08%	0.0000%	0.000%
11	Long Term Debt	5,674,817	46%	4.31%	1.98%	25.8%	0.08%	0.0207%	0.021%
12		12,363,429	100%		7.66%			0.0800%	0.099%

	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:	
13	Total Equity Component (Lines 1 and 9)	6.118%
14	Total Debt Component (Lines 2, 3 , 4 , and 11)	1.651%
15	**Total Revenue Requirement Rate of Return**	**7.769%**

Effective Tax Rate: 23.793%

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

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20220001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2021 - December 2021

REDACTED
DIRECT TESTIMONY OF
Anthony Salvarezza

April 1, 2022

Q. Please state your name and business address.

A. My name is Anthony Salvarezza. My business address is 299 First Ave North, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as General Manager Regional Services. DEF is a wholly owned subsidiary of Duke Energy Corporation ("Duke Energy").

Q. Describe your responsibilities as General Manager of Regional Services.

A. As General Manager of Regional Services, I am responsible for leading and directing project engineering, project management, outage management, business planning and specialized maintenance in Regulated and Renewable Energy ("RRE"). I am responsible for safe, reliable, efficient, economic, environmental, and regulatory compliant maintenance activities through the development and implementation of processes and programs. Within this scope, I ensure longer term activities such as outage management, project scoping, planning, scheduling, execution, and turnover are managed consistently in accordance with the established Project Management Center of Excellence ("PMCoE") guidelines and a standardized set of methodologies and procedures. During non-outage periods, I am responsible for development and implementation of capital and O&M projects across DEF. My position is responsible for direct oversight and direction for 6 - 8 direct reports and a regional organization of approximately 80 employees.

As Regional Services GM, I am also responsible for managing internal and external resources used in the project engineering, project management, outage management, and maintenance services provided to the DEF RRE group. Ultimately, I am responsible for securing, planning and execution of outages, projects, and plant maintenance on approximately 11,000 MWs of generation residing in the state of Florida.

Q. Please describe your educational background and professional experience.

A. I have an Associate in Science electronics engineering, certification in distributed control system engineering, and a bachelor's degree in business. In addition, I have 44 years of related electric industry experience including numerous positions of increasing responsibility over my 44 years of employment with Duke Energy and its predecessors.

<u>Introduction</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the cause of the combustion turbine outages at the Bartow combined cycle plant, explain the Company's response to the outages and steps to mitigate the risk of further outages, and ultimately to explain how the Company has at all times acted reasonably and prudently.

Q. Please provide a summary of your testimony.

A. My testimony explains the reasonableness and prudence of DEF's decisions and actions in relation to discovery of latent damage to the Bartow Combined Cycle ("Bartow CC") Combustion Turbine Generators ("CTGs") and the resulting outages, given the information known or reasonably knowable by DEF at the time those decisions were made and those actions were taken. Moreover, I explain how DEF prudently operated the CTGs at all times, including during the period when DEF now believes the damage to the units was initiated, and therefore that DEF's operation of the units did not initiate the damage to the units – a conclusion fully supported by the Original Equipment Manufacturer's ("OEM") root cause analysis. Finally, I explain that the CTG damage and outages currently at issue are completely unrelated to the Commission's previous determination of imprudence related to the operation of the Bartow Steam Turbine.

As I explain in detail below, as a result of standard maintenance testing, DEF first learned in March 2020 that one of the Bartow CTGs (Unit 4B) was damaged by [redacted] years earlier. Because the temperature alarms were never triggered, DEF could not have known of the issue during this period of operation, which ended after the OEM replaced a degraded component within the CTGs. During this period, DEF followed the OEM-provided operation parameters and completed all OEM-recommended inspections and maintenance, and therefore did not cause the damage.

I also explain why DEF's decisions and actions with regard to addressing the likelihood, though not certainty, that similar damage had been initiated on the remaining units were both reasonable and prudent given the information available to DEF. Given the type and location of the damage, there was no non-destructive testing available that could have been performed to definitively confirm the existence of the suspected damage or when such damage, if present, would reasonably be expected to propagate to the point of failure. Given the limited information available to DEF and the limited options available, I explain that the Company's plan to mitigate against future damage, which was adjusted over time as more information came available, was reasonable and prudent.

Finally, I explain that there is no correlation from an engineering or operational standpoint between the outages at issue and the Commission's previous finding of imprudence related to a separate component of the Bartow plant.

In sum, under the well-known standard of what a reasonable utility manager would do given the facts and circumstances known or reasonably knowable at the time, my testimony demonstrates that DEF's decisions and actions have at all times been prudent and DEF should be permitted to recover the replacement power costs incurred.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit No.__ (AS-1), Root Cause Analysis (Confidential);
- Exhibit No. __ (AS-2), Siemens Product Bulletin PB-08-5038-GN-EN-01 [redacted] (Confidential); and
- Exhibit No. __ (AS-3), Siemens Product Bulletin PB3-13-0008-GN-EN-01 [redacted] (Confidential).

These exhibits are the property of Siemens Energy, Inc., and are designated as proprietary and confidential by Siemens. Therefore, DEF is seeking confidentiality to protect the third-party's interest in these materials.

Background

Q. Can you please provide a summary and timeline of events relating to the Bartow CTG outages?

A. Yes. The Bartow CC came online in summer 2009. There are four (4) Combustion Turbines ("CT") attached to Siemens model SGen6-1000A Combustion Turbine Generators ("CTG"). During planned outages in fall 2012 and spring 2013, DEF performed an inspection of the [redacted] consistent with guidance provided by Siemens Product Bulletin PB-08-5038-GN-EN-01 (Exhibit No. __ (AS-2)) and later updated by PB3-13-0008-GN-EN-01 (Exhibit No. __ (AS-3)). DEF discovered the [redacted] were degraded and, consistent with the OEM's guidance, contracted with Siemens to install upgrades.

As I explain below, unbeknownst to DEF, operation of the CTGs with the degraded [redacted] ultimately led to a series of outages impacting each of the CTGs: Unit 4B in 2019 (extension of a planned outage), Unit 4A in 2021 (forced outage), Unit 4C in 2021 (forced outage), and Unit 4D in 2021 (planned outage).

Q. Can you please provide more detail regarding these outages?

A. In late 2019, during a planned maintenance outage on Unit 4B CTG, the unit faulted during high potential ("hipot") maintenance testing. The hipot test, which was conducted in accordance with Institute of Electrical and Electronics Engineers ("IEEE") Standard 95 guidance with a target test voltage of 33 kV, revealed flaws in the insulation on stator bars T47 and T12. As a result of the root cause analysis ("RCA") finalized in March 2020, DEF determined similar damage could eventually manifest itself at the remaining CTGs at an indeterminate point in the future. The RCA is discussed in detail below and attached as Exhibit No. __ (AS-1).

In January 2021, the Unit 4A CTG experienced an in-service failure that DEF believed to be of the same cause. Later, in May 2021, the Unit 4C CTG likewise experienced a similar in-service failure. As a result, DEF accelerated the Unit 4D planned stator core rewind from 2022 to June 2021, eliminating the risk of an in-service failure on that unit.

<u>Root Cause Analysis</u>

Q. Did DEF perform Root Cause Analyses to determine the cause of these failures?

A. No. DEF contracted with Siemens to prepare the RCA after the Unit 4B CTG failed the maintenance hipot testing mentioned above. Because DEF determined the RCA's main contributor likely also applied to the other units, DEF determined a separate RCA was unnecessary when similar damage led to forced outages of Units 4A and 4C. That is, the same equipment and operating conditions were present in all four CTGs for the same duration, and therefore the resulting damage discovered on Unit 4B was considered likely to develop on the other units at some unknown point in the future. However, it was also clear that the damage DEF suspected had been initiated, if it existed at all, had not propagated to the same degree on Units 4A, 4C, and 4D at that time.[1]

Q. Please provide an overview of the Root Cause Analysis for the outages.

A. The outages were caused by stator bar failures. Despite the fact the temperatures of the stator core windings never triggered the OEM established RTD alarm, the stator bar failures were most likely initiated by [redacted]. The RCA determined the "main contributor" to the [redacted] was [redacted] which led to a period of operation at higher temperature levels than the [redacted]. The units' normal load cycling [redacted]

[1] The other units had each recently underwent the same maintenance hipot test at the same voltage levels and passed without any findings or engineering concerns (Unit 4A, 2019; Unit 4C, 2018; and Unit 4D, 2019).

[redacted].

Q. Can you please elaborate on the RCA findings?

A. Yes. As mentioned above, in the fall 2019, in advance of return to service from a planned outage, maintenance high potential (hi-pot) testing on Unit 4B indicated stator winding faults on the CTG. Further investigation revealed two stator winding bars of two different phases had faulted to ground [redacted]

Forensic analysis determined the [redacted] Finally, the OEM established the "main contributor" to the [redacted] as [redacted] Exhibit No. __ (AS-1), p. 1.

What all this means is that the faulted stator bars resulted from [redacted]. This failure mode naturally led to the question of what led to the relatively [redacted].

The OEM analyzed the operational life of the unit to confirm or refute as many as eleven (11) secondary level elements. Its review of data noted that the stator slot

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temperatures dropped in early 2013, while the generator output (MW and MVAR) remained stable. It further found:

[redacted].

Id. at p. 20.

Thus, the OEM recognized that the [redacted] were a symptom of the degraded [redacted]. When the [redacted] were replaced with an upgrade, the operating temperature was reduced to the lower operating range while generator output remained consistent (i.e., the [redacted] were not a symptom of the units being run outside of the OEM's established operating parameters). However, unbeknownst to DEF at the time, the [redacted]. *See id.* at p. 24.

Q. Why did the Company conclude that similar damage was likely to have occurred at the other Bartow CTGs?

A. The Company reasoned that, because the other three (3) CTGs operated at similar temperatures for a similar period of time (prior to receiving the same upgrades), it

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was likely that they had also suffered damage to the stator bars that would eventually require remediation – though it was unknown when that time would be.

Q. Did the stator winding temperatures observed during the 2009-2013 timeframe provide any basis for concern?

A. No. The stator winding temperature is monitored by an RTD alarm that alerts the Company if the stator winding temperature exceeds the OEM recommended threshold. The OEM alarm is based on [redacted], giving an alarm around [redacted] and unload at approximately [redacted], depending on specific ambient conditions on a particular day. It is important to note the alarm set-points allow for engineered operating margins built into generator design; for example, the alarm set-point of [redacted] is more than [redacted] below the IEEE-established failure point for Class F Insulation (the type of insulation at issue) of 311°F (155°C). The point being, given the information reasonably available to DEF during the 2009-2013 timeframe, according to the indicated stator RTD temperatures the insulation remained well below its temperature rating at all times. In fact, in 2013 when Siemens performed the [redacted] replacement discussed above, it inspected the end windings and main leads and found no signs of over-heating.

Q. Has DEF's and the OEM's understanding of the actual operating temperatures experienced during the 2009-2013 timeframe changed?

A. Yes, based on the findings of the RCA, the OEM and DEF now believe that the [redacted]. *See id.* at pp. 19-21, 23. However, as discussed above, because the Bartow CTGs never triggered the RTD alarms, and because those alarms were set at a point that provided approximately [redacted] of margin before reaching the insulation's IEEE-established temperature rating, DEF had no way of knowing the temperature likely exceeded the rating limit and no reason for concern or to seek comparison with the remainder of Siemens' fleet.

Q. Did DEF operate the Bartow CTGs within the operating parameters established by the OEM?

A. Yes, at all times DEF operated the units consistent with the OEM's instructions as provided in the operating manual. DEF reviewed the units' operating history in Pi data from 2010 to the 2012/2013 outages when the [redacted] upgrade was performed. The data, which was sampled on an hourly basis, showed zero instances of operating the generators outside the OEM ratings as defined on the generator capability curve provided in that manual.

Specifically, the generators have a maximum capability of [redacted] MW and the operating history shows the maximum output of any of the four (4) generators was 213 MW. At this output of 213 MW, the allowable reactive power (MVAR) rating is [redacted] MVAR - the maximum MVAR output actually generated across this time period was 83 MVAR (as MW load decreases, the MVAR allowable increases). The table below provides the maximum MW and both maximum and minimum MVAR output of the four (4) CTGs over the period in question.

Unit	***Max MW***	***Max MVAR***	***Min MVAR***
4A	*211*	*80*	*-77*
4B	*209*	*71*	*-71*
4C	*210*	*77*	*-73*
4D	*213*	*83*	*-75*

Furthermore, the RCA shows that the OEM did not identify operation of the CTGs outside of their preapproved operating parameters as the cause of the damage to Unit 4B. The RCA determined that the main contributing cause of the stator bar damage was [redacted] which led to increased [redacted], but again, the OEM-established RTD temperature alarm was never triggered. The RCA also shows that after the degraded [redacted] were replaced in 2012 and 2013, the [redacted] while the generator output (MW and MVAR) remained stable. *See id.* at p. 20 & Fig. 16.

In short, DEF operated the CTGs within the OEM's defined operating parameters; hence, DEF's operation was not the cause of [redacted] and therefore not the cause of the damage to the units. Instead, the degraded [redacted], which DEF replaced in accordance with OEM recommendations once it discovered the issue, [redacted] and caused the [redacted].

<u>DEF's Actions to Prudently Mitigate the Risk of Failure</u>

Q. What steps did DEF take to prudently manage the likelihood of damage at the remaining units?

A. Once DEF learned the cause of Unit 4B's damage and the likelihood that the remaining units may have experienced similar damage, the Company took several proactive steps to evaluate the remaining units, monitor unit operations to detect damage propagation (to the extent possible), and ultimately remediate the likelihood of damage to the remaining units. First, DEF reconfigured the Electromagnetic Signature Analysis ("EMSA") collars on Units 4A and 4C[2] to potentially identify insulation degradation during continued operation.[3] Second, DEF scheduled borescope inspections on Units 4A and 4C to look for any visual indications of buckled insulation.[4] Third, DEF issued procurement specifications in anticipation of a bid event for a spare set of stator bars to have on hand in case of an in-service failure or failed indicative testing of one of the remaining CTGs. Finally, DEF scheduled generator rewinds for the remaining units, notwithstanding that a rewind would not typically be required for thousands of equivalent operating hours.

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[2] As noted above, Units 4A and 4D underwent hipot testing in spring and fall 2019, respectively, resulting in no negative findings or engineering concerns.

[3] DEF previously relocated the EMSA collars on Units 4B and 4D in fall 2019.

[4] Unit 4D was thoroughly inspected in fall 2019 (when the Unit 4B damage was discovered), so a borescope inspection was unnecessary.

Q. Why did DEF take these specific actions?

A. As described above, each action DEF took was intended to reduce the risk exposure on the generators while continuing to provide a safe, reliable, and cost-effective power supply to DEF's customers. The EMSA collar relocation enhanced monitoring of the generator internals for signs of electrical abnormalities to provide a better understanding of internal generator health. The borescope inspections that were scheduled for spring 2021 planned outages were intended to specifically look for buckled insulation to assess risk on these units (although the ability to detect the buckling of insulation with a small borescope camera was not a proven method). The planned stator rewinds to replace the stator bars were significantly shortened (by over 10 years) since the RCA conclusions indicated the potential for a shortened life interval for the stator bar components within the generator.

Q. Please explain the reconfigured EMSA collars on Units 4A and 4C.

A. EMSA monitors electromagnetic interference that is emitted from a generator due to abnormalities. These abnormalities include, but are not limited to, partial discharge, corona, arcing, or gap discharges. While EMSA has been used for decades as a temporary measurement tool for motors, transformers, and generators, only more recently has the technology been applied in a permanent installation for continuous monitoring. When DEF first installed the radio frequency collars used to collect the electromagnetic signature for the Bartow generators, the collars were installed on the RTD wires consistent with industry practice at the time. More recent industry research concluded that EMSA signals are much higher fidelity when the collars are installed on the Neutral Ground Cable, since this is a more direct measurement of electromagnetic signatures within the generator and does not rely as much on the radiated signal, which can be heavily affected by ambient readings. Due to these findings, DEF implemented a plan to relocate the EMSA collars from the RTD wires to the Neutral Ground Cable to improve the EMSA signals and monitor for arcing within the generator. The EMSA collars were relocated on Units 4B and 4D in fall 2019 and on Units 4A and 4C in fall 2020.

EMSA is a dynamic and long-term trending tool for measuring slow degradation due to the long scan time and manual analysis methods used. The relocation of the collars was intended to ensure the inside of the generator was monitored as closely as possible to retain as much margin as possible given the risks identified. However, DEF recognized that EMSA would not typically detect cracks in insulation on a high voltage stator bar, as when insulation is breached the failure happens in milliseconds and not slowly over time. EMSA was a tool to enhance knowledge of generator internals, and not directly tied to detection and prevention of a stator bar failure that by its nature would be a rapidly progressing event.

Q. Please explain the Company's plan to rewind the remaining generators.

A. As discussed above, after learning of the main contributing cause of failure as determined by the OEM's RCA, DEF scheduled each of the three remaining CTGs for a stator rewind during upcoming planned major outage windows. The stator rewind for Unit 4D was scheduled for the spring 2022 planned major outage, the

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stator rewind for Unit 4A was scheduled for the fall 2023 planned major outage, and the stator rewind for Unit 4C was scheduled for the fall 2024 planned major outage. This schedule was intended to allow DEF to take advantage of previously scheduled outages in a measured cadence to avoid concurrent CTG outages (maximizing output from the remainder of the plant by allowing for operation in 3 on 1 configuration), to minimize the number of planned outages by performing multiple maintenance tasks during the same outages, and to provide time for the OEM to manufacture the stator bars and support the outages.

In an effort to prudently address and mitigate the risks to the other units suggested by the Unit 4B RCA, while also attempting to retain the benefits of Bartow's low-cost generation for customers by spacing the scheduling of planned major outages, DEF scheduled these stator rewinds to occur much earlier in the units' operating life than the Duke Energy fleet standard recommendation of [redacted] equivalent hours for this type of air-cooled unit. Specifically, Unit 4D was planned for a rewind at ~103,000 equivalent hours, Unit 4A at ~109,000 equivalent hours, and Unit 4C at ~116,000 equivalent hours.

Q. Was DEF able to maintain the schedule of proactive outages discussed above?

A. No, Unit 4A experienced an unexpected in-service failure in January 2021 that required a forced outage lasting into April 2021; as discussed above, due to the nature of the suspected damage and the limitations on available testing, DEF could not have anticipated when such a failure may occur (if at all). As a result of this outage, DEF accelerated the scheduled Unit 4C planned outage up to fall 2023.

However, shortly after Unit 4A's return to service, Unit 4C also experienced an in-service failure in May 2021.

Q. Did these unexpected occurrences further alter DEF's plan?

A. Yes. Given the two in-service failures in a short period of time, DEF determined that this new information required a strategy shift. Therefore, the Company accelerated the planned outage of Unit 4D from spring 2022 to June 2021. DEF completed the stator rewinds and returned Units 4C and 4D to service in November and October 2021, respectively.

Q. You indicated that the two forced outages in a short period of time was "new information" that led to DEF's strategy change. Given that DEF determined in March 2020 that there was a likelihood of latent damage to the remaining units, how did the in-service failures constitute "new information"?

A. The new information I was referring to is the speed at which the [redacted], which was thought but not definitively known to exist, was propagating on the remaining units notwithstanding operation within the OEM-provided parameters and the normal fleet operating temperatures. Recall that DEF became aware of the main contributing cause of the damage to Unit 4B in March 2020. At that time, the units had been operating for approximately seven (7) years after the [redacted] is believed to have occurred without an in-service failure known to have resulted from the damage identified in the RCA; that is, DEF had only its experience and did not have any means to formulate a trend or projection for when subsequent failures may occur. At the time of the RCA conclusion in March 2020, DEF discussed the likelihood of failure with the OEM to gain a wider fleet perspective from the OEM fleet of similar generators, and the OEM did not have any specific fleet data or recommendation on likelihood or urgency of failure.

However, the in-service failure of Unit 4A followed shortly thereafter by Unit 4C provided new data points for the Company's risk analysis, which therefore led to the prudent decision to further accelerate the Unit 4D planned outage to June 2021, ~97,802 equivalent hours into its operational life.

Q. Given that Unit 4A failed in January 2021, would it have been possible for DEF to accelerate the planned outages at the remaining two units to avoid in-service failures?

A. The only guaranteed way to avoid an in-service failure at the two remaining units would have been immediately removing them from service. To immediately remove the units from service would have meant the Bartow plant would have been operating in in 1 on 1 configuration until Unit 4A returned to service in April 2021, bringing the plant back to 2 on 1 configuration until Units 4C and 4D could be rewound. Of course, the timing of the return to service for these units would have been very uncertain, as the outage duration would have been dependent on the ability of the OEM to fabricate the new stator windings and provide the workforce to perform the actual rewind.

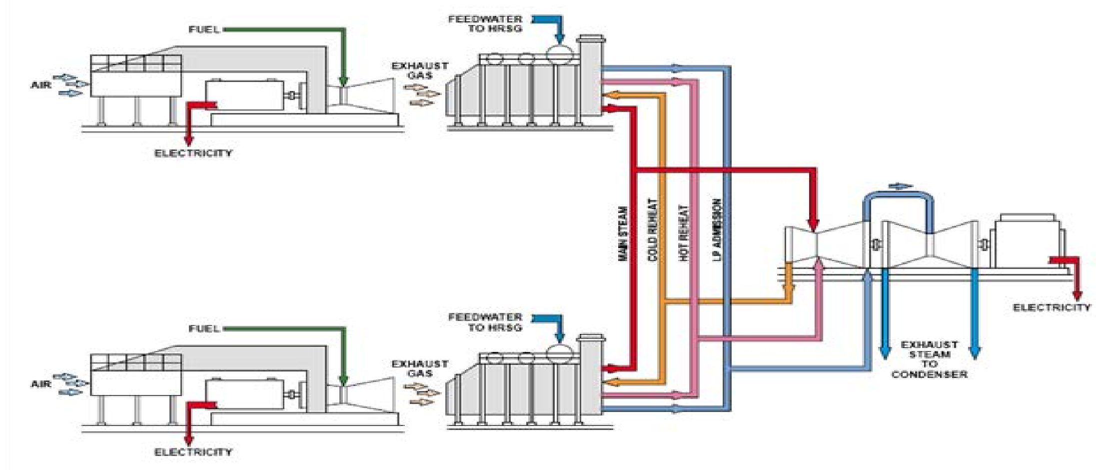
Another possibility would have been to remove one of the remaining CTGs from service when Unit 4A returned to service in April 2021. However, that may or may not have avoided a future in-service failure – for example, DEF may have opted to take Unit 4D out of service in April (as it was the next planned outage), but we now know that Unit 4C failed in May so a forced outage on that unit would not have been avoided. Alternatively, DEF may have opted to take Unit 4C out of service reasoning that Unit 4D had a planned outage scheduled for Spring 2022 and thus less risk of an in-service failure; what we do not and cannot know is when (or if) Unit 4D would have failed before the outage at Unit 4C could have been completed.

The point here is not to identify which of the alternative hypothetical scenarios may have been preferable, it is to underscore that any of the alternatives ultimately not selected carried its own set of risks and unknowns. For anybody to claim "what would have occurred had DEF chosen a different path" would be an exercise in conjecture or post hoc rationalization utilizing the benefit of hindsight, a luxury not available to utility managers at the time decisions must be made.

<u>The Set-up of the Bartow Combined Cycle and Relationship between the CTGs and Steam Turbine</u>

Q. Can you please explain how the Bartow Combined Cycle Plant is configured?

A. Yes. At the Bartow Combined Cycle Plant, natural gas powers the four combustion turbines to turn four separate combustion turbine generators; this process creates excess steam which is then reheated and used to turn the steam turbine ("ST"), which then powers a steam turbine generator. Below is a diagram of a typical 2 on 1 combined cycle. Though Bartow is a 4 on 1 combined cycle, the operational concept is the same with four (4) combustion turbines feeding one steam turbine.



Q. Are you familiar with the Commission's finding that DEF imprudently operated the Bartow Steam Turbine from 2009 to 2012?

A. Yes, I am aware of the Commission's determination, though I would also note that the Company does not agree with that finding and it is currently under appeal at the Florida Supreme Court.

Q. Is the damage to Bartow's Combustion Turbine Generators related to the Commission's previous determination regarding the Steam Turbine?

A. No, the two are unrelated. The Commission's previous finding was premised on the use of the ST in a 4 on 1 configuration (it was originally designed for 3 on 1 operation) resulting in the ST producing MWs in excess of its nameplate capacity without the OEM's explicit approval of operation at that level. The previous case had nothing at all to do with the CTGs and in fact the order does not even mention the CTGs (other than in the context of Bartow being operated as a combined cycle

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plant). Said differently, the prior order concerned operation of the Bartow Steam Turbine and contained no discussion regarding the operation of the CTGs. In fact, the Commission specifically noted "that this case is highly fact specific and for that reason will have limited precedential value."[5]

<u>Conclusion</u>

Q. In your opinion, has DEF acted prudently?

A. Yes. First, as I have explained above, the Company's operation of the units did not initiate the damage to the units, rather it was a function of [redacted] that the Company simply could not have contemporaneously known about. When DEF later determined the damage was likely present on the other units, it was confronted with a lack of information about: a) whether the other units (or some subset of those units) were actually damaged, and if so to what degree; and b) if the units were damaged, at what point the damage would be identifiable via available testing or when the units may experience a failure. Given this dearth of information, DEF made the reasonable decision to continue operating the units (benefitting customers by the continued generation of low-cost energy) and prudently took steps intended to mitigate the risk of future in-service failure. What we now know, but could not have known at the time, was the relatively short period in which the hypothesized damage would manifest. As I have explained above, as the Company learned additional facts, it prudently incorporated the new information into its analysis and made reasonable adjustments where possible. When making operations decisions in

[5] Order No. PSC-2020-0368A-FOF-EI, at p. 22.

real-time, the Company does not have the benefit of hindsight and cannot make decisions based on unknown or unknowable information. When the Company's actions are evaluated based on the standard of what a reasonable utility manager would do given the facts as they were known or reasonably knowable, DEF acted prudently.

Q. Does that conclude your testimony?

A. Yes.

Duke Energy Florida, LLC
Docket No. 20220001
Witness: Salvarezza
Exhibit No. ___(AS-1)

REDACTED
Pages 1 through 26
are confidential in their entirety.

REDACTED
Pages 1 through 6
are confidential in their entirety.

Duke Energy Florida, LLC
Docket No. 20220001
Witness: Salvarezza
Exhibit No. ___(AS-3)

REDACTED
Pages 1 through 6
are confidential in their entirety.