Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A8

PURCHASED POWER

(Exclusive of Economy Energy Purchases)
For the Period/Month of: JANUARY 2020 REVISED 7_27_2020

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) KWH FOR OTHER UTILITIES (000)	(5) KWH FOR INTERRUP-TIBLE (000)	(6) KWH FOR FIRM (000)	(7) CENTS/KWH (a) FUEL COST	(7) CENTS/KWH (b) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
ESTIMATED:								
FPL AND GULF/SOUTHERN	MS	27,981			27,981	2.426041	7.733829	678,819
TOTAL		27,981	0	0	27,981	2.426041	7.733829	678,819
ACTUAL:								
FPL	MS	11,657			11,657	2.628498	7.792108	306,404
GULF/SOUTHERN		23,471			23,471	1.946321	5.441916	456,821
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
TOTAL		35,128	0	0	35,128	4.574819	7.792108	763,225
CURRENT MONTH:								
DIFFERENCE		7,147	0	0	7,147	2.148778	0.05828	84,406
DIFFERENCE (%)		25.5%	0.0%	0.0%	25.5%	88.6%	0.8%	12.4%
PERIOD TO DATE:								
ACTUAL	MS	35,128			35,128	2.172697	2.272697	763,225
ESTIMATED	MS	27,981			27,981	2.426041	2.526041	678,819
DIFFERENCE		7,147	0	0	7,147	(0.253344)	-0.253344	84,406
DIFFERENCE (%)		25.5%	0.0%	0.0%	25.5%	-10.4%	-10.0%	12.4%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A8a

ENERGY PAYMENT TO QUALIFYING FACILITIES

For the Period/Month of: JANUARY 2020 REVISED 7_27_2020

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) KWH FOR OTHER UTILITIES (000)	(5) KWH FOR INTERRUP-TIBLE (000)	(6) KWH FOR FIRM (000)	(7) CENTS/KWH (a) FUEL COST	(7) CENTS/KWH (b) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
ESTIMATED:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		17,400			17,400	8.003356	8.003356	1,392,584
TOTAL		17,400	0	0	17,400	8.003356	8.003356	1,392,584
ACTUAL:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		16,487			16,487	7.106032	7.106032	1,171,582
TOTAL		16,487	0	0	16,487	7.106032	7.106032	1,171,582
CURRENT MONTH:								
DIFFERENCE		(913)	0	0	(913)	-0.897324	-0.897324	(221,002)
DIFFERENCE (%)		-5.2%	0.0%	0.0%	-5.2%	-11.2%	-11.2%	-15.9%
PERIOD TO DATE:								
ACTUAL	MS	16,487			16,487	7.106032	7.106032	1,171,582
ESTIMATED	MS	17,400			17,400	8.003356	8.003356	1,392,584
DIFFERENCE		(913)	0	0	(913)	-0.897324	-0.897324	(221,002)
DIFFERENCE (%)		-5.2%	0.0%	0.0%	-5.2%	-11.2%	-11.2%	-15.9%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A9

ECONOMY ENERGY PURCHASES

INCLUDING LONG TERM PURCHASES
For the Period/Month of: JANUARY 2020 REVISED 7_27_2020

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS. COST CENTS/KWH	TOTAL $ FOR FUEL ADJ. (3) X (4) $	COST IF GENERATED		FUEL SAVINGS (6)(b)-(5) $
					(a) CENTS/KWH	(b) TOTAL COST $	
ESTIMATED:							
TOTAL							
ACTUAL:							
TOTAL							

FOOTNOTE: PURCHASED POWER COSTS INCLUDE CUSTOMER, DEMAND & ENERGY CHARGES TOTALING 0

CURRENT MONTH:							
DIFFERENCE							
DIFFERENCE (%)							
PERIOD TO DATE:							
ACTUAL							
ESTIMATED							
DIFFERENCE							
DIFFERENCE (%)							

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: FEBRUARY 2020 REVISED 7_27_2020

		DOLLARS				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)			0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	550,079	855,163	(305,084)	-35.7%	29,824	30,528	(704)	-2.3%	1.84442	2.80124	(0.95682)	-34.2%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	1,368,910	1,138,209	230,701	20.3%	29,824	30,528	(704)	-2.3%	4.58996	3.72841	0.86155	23.1%
11	Energy Payments to Qualifying Facilities (A8a)	995,741	1,263,018	(267,277)	-21.2%	14,912	15,700	(788)	-5.0%	6.67759	8.04470	(1.36711)	-17.0%
12	TOTAL COST OF PURCHASED POWER	2,914,730	3,256,390	(341,660)	-10.5%	44,736	46,228	(1,492)	-3.2%	6.51545	7.04420	(0.52875)	-7.5%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					44,736	46,228	(1,492)	-3.2%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	85,200	125,385	(40,185)	-47.1%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	2,829,530	3,131,005	(301,475)	-9.6%	44,736	46,228	(1,492)	-3.2%	6.32500	6.77296	(0.44796)	-6.6%
21	Net Unbilled Sales (A4)	(110,408) *	(40,707) *	(69,701)	171.2%	(1,746)	(601)	(1,145)	190.4%	(0.25229)	(0.09246)	(0.15983)	172.9%
22	Company Use (A4)	2,167 *	1,896 *	271	14.3%	34	28	6	22.4%	0.00495	0.00431	0.00064	14.9%
23	T & D Losses (A4)	169,763 *	187,882 *	(18,119)	-9.6%	2,684	2,774	(90)	-3.2%	0.38791	0.42674	(0.03883)	-9.1%
24	SYSTEM KWH SALES	2,829,530	3,131,005	(301,475)	-9.6%	43,763	44,027	(264)	-0.6%	6.46557	7.11155	(0.64598)	-9.1%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	2,829,530	3,131,005	(301,475)	-9.6%	43,763	44,027	(264)	-0.6%	6.46557	7.11155	(0.64598)	-9.1%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	2,829,530	3,131,005	(301,475)	-9.6%	43,763	44,027	(264)	-0.6%	6.46557	7.11155	(0.64598)	-9.1%
28	GPIF**												
29	TRUE-UP**	161,204	161,204	0	0.0%	43,763	44,027	(264)	-0.6%	0.36836	0.36615	0.00221	0.6%
30	TOTAL JURISDICTIONAL FUEL COST (Excluding GSLD Apportionment)	2,990,734	3,292,209	(301,475)	-9.2%	43,763	44,027	(264)	-0.6%	6.83393	7.47770	(0.64377)	-8.6%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									6.94389	7.59802	(0.65413)	-8.6%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									6.944	7.598	(0.654)	-8.6%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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Company: **FLORIDA PUBLIC UTILITIES COMPANY**

CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: FEBRUARY 2020 REVISED 7_27_2020

		PERIOD TO DATE	DOLLARS			PERIOD TO DATE	MWH			CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)	0	0	0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	1,313,304	1,533,982	(220,678)	-14.4%	64,952	58,508	6,444	11.0%	2.02196	2.62181	(0.59985)	-22.9%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	2,791,283	2,623,355	167,928	6.4%	64,952	58,508	6,444	11.0%	4.29746	4.48372	(0.18626)	-4.2%
11	Energy Payments to Qualifying Facilities (A8a)	2,167,323	2,655,602	(488,279)	-18.4%	31,399	33,100	(1,701)	-5.1%	6.90256	8.02297	(1.12041)	-14.0%
12	TOTAL COST OF PURCHASED POWER	6,271,910	6,812,939	(541,029)	-7.9%	96,351	91,608	4,742	5.2%	6.50945	7.43702	(0.92757)	-12.5%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					96,351	91,608	4,742	5.2%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	190,054	247,309	(57,255)	-23.2%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	6,081,856	6,565,630	(483,774)	-7.4%	96,351	91,608	4,742	5.2%	6.31220	7.16705	(0.85485)	-11.9%
21	Net Unbilled Sales (A4)	38,855 *	(85,625) *	124,480	-145.4%	616	(1,195)	1,810	-151.5%	0.04323	(0.09814)	0.14137	-144.1%
22	Company Use (A4)	4,247 *	4,243 *	4	0.1%	67	59	8	13.6%	0.00472	0.00486	(0.00014)	-2.9%
23	T & D Losses (A4)	364,908 *	393,973 *	(29,065)	-7.4%	5,781	5,497	284	5.2%	0.40596	0.45156	(0.04560)	-10.1%
24	SYSTEM KWH SALES	6,081,856	6,565,630	(483,774)	-7.4%	89,887	87,247	2,640	3.0%	6.76611	7.52533	(0.75922)	-10.1%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	6,081,856	6,565,630	(483,774)	-7.4%	89,887	87,247	2,640	3.0%	6.76611	7.52533	(0.75922)	-10.1%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	6,081,856	6,565,630	(483,774)	-7.4%	89,887	87,247	2,640	3.0%	6.76611	7.52533	(0.75922)	-10.1%
28	GPIF**												
29	TRUE-UP**	322,408	322,408	(0)	0.0%	89,887	87,247	2,640	3.0%	0.35868	0.36954	(0.01086)	-2.9%
30	TOTAL JURISDICTIONAL FUEL COST	6,404,264	6,888,038	(483,774)	-7.0%	89,887	87,247	2,640	3.0%	7.12479	7.89487	(0.77008)	-9.8%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									7.23943	8.02190	(0.78247)	-9.8%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.239	8.022	(0.783)	-9.8%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: FEBRUARY 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. Fuel Cost & Net Power Transactions								
1. Fuel Cost of System Net Generation	$ 0	$ 0	$ 0	0.0%	$ 0	$ 0	$ 0	0.0%
1a. Fuel Related Transactions (Nuclear Fuel Disposal)								
2. Fuel Cost of Power Sold								
3. Fuel Cost of Purchased Power	550,079	855,163	(305,084)	-35.7%	1,313,304	1,533,982	(220,678)	-14.4%
3a. Demand & Non Fuel Cost of Purchased Power	1,368,910	1,138,209	230,701	20.3%	2,791,283	2,623,355	167,928	6.4%
3b. Energy Payments to Qualifying Facilities	995,741	1,263,018	(267,277)	-21.2%	2,167,323	2,655,602	(488,279)	-18.4%
4. Energy Cost of Economy Purchases								
5. Total Fuel & Net Power Transactions	2,914,730	3,256,390	(341,660)	-10.5%	6,271,910	6,812,939	(541,029)	-7.9%
6. Adjustments to Fuel Cost (Describe Items)								
6a. Special Meetings - Fuel Market Issue	25,243	17,850	7,393	41.4%	27,203	35,700	(8,497)	-23.8%
7. Adjusted Total Fuel & Net Power Transactions	2,939,972	3,274,240	(334,267)	-10.2%	6,299,113	6,848,639	(549,526)	-8.0%
8. Less Apportionment To GSLD Customers	85,200	125,385	(40,185)	-32.1%	190,054	247,309	(57,255)	-23.2%
9. Net Total Fuel & Power Transactions To Other Classes	$ 2,854,772	$ 3,148,855	$ (294,082)	-9.3%	$ 6,109,059	$ 6,601,330	$ (492,271)	-7.5%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: FEBRUARY 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
B. Sales Revenues (Exclude Revenue Taxes & Franchise Taxes)								
1. Jurisidictional Sales Revenue (Excluding GSLD)	$	$	$		$	$	$	
a. Base Fuel Revenue								
b. Fuel Recovery Revenue	3,464,288	3,282,531	181,757	5.5%	6,332,145	6,502,659	(170,514)	-2.6%
c. Jurisidictional Fuel Revenue	3,464,288	3,282,531	181,757	5.5%	6,332,145	6,502,659	(170,514)	-2.6%
d. Non Fuel Revenue	2,158,515	2,034,390	124,126	6.1%	4,409,102	4,265,967	143,136	3.4%
e. Total Jurisdictional Sales Revenue	5,622,803	5,316,921	305,883	5.8%	10,741,247	10,768,626	(27,378)	-0.3%
2. Non Jurisdictional Sales Revenue	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales Revenue (Excluding GSLD)	$ 5,622,803	$ 5,316,921	$ 305,883	5.8%	$ 10,741,247	$ 10,768,626	$ (27,378)	-0.3%
C. KWH Sales (Excluding GSLD)								
1. Jurisdictional Sales KWH	43,681,223	42,526,644	1,154,579	2.7%	89,231,695	84,376,187	4,855,508	5.8%
2. Non Jurisdictional Sales	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales	43,681,223	42,526,644	1,154,579	2.7%	89,231,695	84,376,187	4,855,508	5.8%
4. Jurisdictional Sales % of Total KWH Sales	100.00%	100.00%	0.00%	0.0%	100.00%	100.00%	0.00%	0.0%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: FEBRUARY 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. True-up Calculation (Excluding GSLD)								
1. Jurisdictional Fuel Rev. (line B-1c)	$ 3,464,288	$ 3,282,531	$ 181,757	5.5%	$ 6,332,145	$ 6,502,659	$ (170,514)	-2.6%
2. Fuel Adjustment Not Applicable								
a. True-up Provision	161,204	161,204	0	0.0%	322,408	322,408	(0)	0.0%
b. Incentive Provision								
c. Transition Adjustment (Regulatory Tax Refund)							0	0.0%
3. Jurisdictional Fuel Revenue Applicable to Period	3,303,084	3,121,327	181,757	5.8%	6,009,737	6,180,250	(170,513)	-2.8%
4. Adjusted Total Fuel & Net Power Transaction (Line A-7)	2,854,772	3,148,855	(294,082)	-9.3%	6,109,059	6,601,330	(492,271)	-7.5%
5. Jurisdictional Sales % of Total KWH Sales (Line C-4)	100%	100%	0.00%	0.0%	N/A	N/A		
6. Jurisdictional Total Fuel & Net Power Transactions (Line D-4 x Line D-5 x *)	2,854,772	3,148,855	(294,083)	-9.3%	6,109,059	6,601,330	(492,271)	-7.5%
7. True-up Provision for the Month Over/Under Collection (Line D-3 - Line D-6)	448,312	(27,528)	475,840	-1728.6%	(99,322)	(421,080)	321,758	-76.4%
8. Interest Provision for the Month	(5,219)	(4,213)	(1,006)	23.9%	(10,712)	(6,754)	(3,958)	58.6%
9. True-up & Inst. Provision Beg. of Month	(4,344,271)	431,737	(4,776,008)	-1106.2%	(3,952,348)	666,626	(4,618,974)	-692.9%
9a. Deferred True-up Beginning of Period	-							
10. True-up Collected (Refunded)	161,204	161,204	0	0.0%	322,408	322,408	(0)	0.0%
11. End of Period - Total Net True-up (Lines D7 through D10)	$ (3,739,974)	$ 561,200	$ (4,301,174)	-766.4%	$ (3,739,974)	$ 561,200	$ (4,301,174)	-766.4%

* Jurisdictional Loss Multiplier

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: FEBRUARY 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
E. Interest Provision (Excluding GSLD)							--	--
1. Beginning True-up Amount (lines D-9 + 9a)	$ (4,344,271)	$ 431,737	$ (4,776,008)	-1106.2%	N/A	N/A	--	--
2. Ending True-up Amount Before Interest	(3,734,755)	565,413	(4,300,168)	-760.5%	N/A	N/A	--	--
(line D-7 + Lines D-9 + 9a + D-10)					N/A	N/A	--	--
3. Total of Beginning & Ending True-up Amount	(8,079,026)	997,150	(9,076,176)	-910.2%	N/A	N/A	--	--
4. Average True-up Amount (50% of Line E-3)	$ (4,039,513)	$ 498,575	$ (4,538,088)	-910.2%	N/A	N/A	--	--
5. Interest Rate - First Day Reporting Business Month	1.5900%	N/A	--	--	N/A	N/A	--	--
6. Interest Rate - First Day Subsequent Business Month	1.5100%	N/A	--	--	N/A	N/A	--	--
7. Total (Line E-5 + Line E-6)	3.1000%	N/A	--	--	N/A	N/A	--	--
8. Average Interest Rate (50% of Line E-7)	1.5500%	N/A	--	--	N/A	N/A	--	--
9. Monthly Average Interest Rate (Line E-8 / 12)	0.1292%	N/A	--	--	N/A	N/A	--	--
10. Interest Provision (Line E-4 x Line E-9)	(5,219)	N/A	--	--	N/A	N/A	--	--

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Company: **FLORIDA PUBLIC UTILITIES COMPANY**
CONSOLIDATED ELECTRIC DIVISIONS

Schedule A4

ELECTRIC ENERGY ACCOUNT
Month of: FEBRUARY 2020 REVISED 7_27_2020

	(MWH)	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH DIFFERENCE %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE DIFFERENCE %
1	System Net Generation	0	0	0	0.00%	0	0	0	0.00%
2	Power Sold								
3	Inadvertent Interchange Delivered - NET								
4	Purchased Power	29,824	30,528	(704)	-2.31%	64,952	58,508	6,444	11.01%
4a	Energy Purchased For Qualifying Facilities	14,912	15,700	(788)	-5.02%	31,399	33,100	(1,701)	-5.14%
5	Economy Purchases								
6	Inadvertent Interchange Received - NET								
7	Net Energy for Load	44,736	46,228	(1,492)	-3.23%	96,351	91,608	4,742	5.18%
8	Sales (Billed)	43,763	44,027	(264)	-0.60%	89,887	87,247	2,640	3.03%
8a	Unbilled Sales Prior Month (Period)								
8b	Unbilled Sales Current Month (Period)								
9	Company Use	34	28	6	22.38%	67	59	8	13.64%
10	T&D Losses Estimated @ 0.06	2,684	2,774	(90)	-3.24%	5,781	5,497	284	5.17%
11	Unaccounted for Energy (estimated)	(1,746)	(601)	(1,145)	190.44%	616	(1,195)	1,810	-151.52%
12									
13	% Company Use to NEL	0.08%	0.06%	0.02%	33.33%	0.07%	0.06%	0.01%	16.67%
14	% T&D Losses to NEL	6.00%	6.00%	0.00%	0.00%	6.00%	6.00%	0.00%	0.00%
15	% Unaccounted for Energy to NEL	-3.90%	-1.30%	-2.60%	200.00%	0.64%	-1.30%	1.94%	-149.23%

	($)	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH DIFFERENCE %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE DIFFERENCE %
16	Fuel Cost of Sys Net Gen	-	-	-	0	-	-	-	0
16a	Fuel Related Transactions								
16b	Adjustments to Fuel Cost								
17	Fuel Cost of Power Sold								
18	Fuel Cost of Purchased Power	550,079	855,163	(305,084)	-35.68%	1,313,304	1,533,982	(220,678)	-14.39%
18a	Demand & Non Fuel Cost of Pur Power	1,368,910	1,138,209	230,701	20.27%	2,791,283	2,623,355	167,928	6.40%
18b	Energy Payments To Qualifying Facilities	995,741	1,263,018	(267,277)	-21.16%	2,167,323	2,655,602	(488,279)	-18.39%
19	Energy Cost of Economy Purch.								
20	Total Fuel & Net Power Transactions	2,914,730	3,256,390	(341,660)	-10.49%	6,271,910	6,812,939	(541,029)	-7.94%

	(Cents/KWH)	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH DIFFERENCE %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE DIFFERENCE %
21	Fuel Cost of Sys Net Gen								
21a	Fuel Related Transactions								
22	Fuel Cost of Power Sold								
23	Fuel Cost of Purchased Power	1.844	2.801	(0.957)	-34.17%	2.022	2.622	(0.600)	-22.88%
23a	Demand & Non Fuel Cost of Pur Power	4.590	3.728	0.862	23.12%	4.297	4.484	(0.187)	-4.17%
23b	Energy Payments To Qualifying Facilities	6.678	8.045	(1.367)	-16.99%	6.903	8.023	(1.120)	-13.96%
24	Energy Cost of Economy Purch.								
25	Total Fuel & Net Power Transactions	6.515	7.044	(0.529)	-7.51%	6.509	7.437	(0.928)	-12.48%

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PURCHASED POWER

(Exclusive of Economy Energy Purchases)
For the Period/Month of: FEBRUARY 2020 REVISED 7_27_2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR OTHER UTILITIES (000)	KWH FOR INTERRUP-TIBLE (000)	KWH FOR FIRM (000)	CENTS/KWH (a) FUEL COST	CENTS/KWH (b) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
ESTIMATED:								
FPL AND GULF/SOUTHERN	MS	30,528			30,528	2.801244	6.529655	855,163
TOTAL		30,528	0	0	30,528	2.801244	6.529655	855,163
ACTUAL:								
FPL	MS	8,817			8,817	1.917931	8.746104	169,104
GULF/SOUTHERN		21,007			21,007	1.813561	5.464106	380,975
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
TOTAL		29,824	0	0	29,824	3.731492	8.746104	550,079
CURRENT MONTH:								
DIFFERENCE		(704)	0	0	(704)	0.930248	2.21645	(305,084)
DIFFERENCE (%)		-2.3%	0.0%	0.0%	-2.3%	33.2%	33.9%	-35.7%
PERIOD TO DATE:								
ACTUAL	MS	64,952			64,952	2.021961	2.121961	1,313,304
ESTIMATED	MS	58,508			58,508	2.621811	2.721811	1,533,982
DIFFERENCE		6,444	0	0	6,444	(0.599850)	-0.59985	(220,678)
DIFFERENCE (%)		11.0%	0.0%	0.0%	11.0%	-22.9%	-22.0%	-14.4%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A8a

ENERGY PAYMENT TO QUALIFYING FACILITIES

For the Period/Month of: FEBRUARY 2020 REVISED 7_27_2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR OTHER UTILITIES (000)	KWH FOR INTERRUP-TIBLE (000)	KWH FOR FIRM (000)	CENTS/KWH (a) FUEL COST	CENTS/KWH (b) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
ESTIMATED:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		15,700			15,700	8.044701	8.044701	1,263,018
TOTAL		15,700	0	0	15,700	8.044701	8.044701	1,263,018
ACTUAL:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		14,912			14,912	6.677591	6.677591	995,741
TOTAL		14,912	0	0	14,912	6.677591	6.677591	995,741
CURRENT MONTH:								
DIFFERENCE		(788)	0	0	(788)	-1.367110	-1.367110	(267,277)
DIFFERENCE (%)		-5.0%	0.0%	0.0%	-5.0%	-17.0%	-17.0%	-21.2%
PERIOD TO DATE:								
ACTUAL	MS	31,399			31,399	6.902560	6.902560	2,167,323
ESTIMATED	MS	33,100			33,100	8.022967	8.022967	2,655,602
DIFFERENCE		(1,701)	0	0	(1,701)	-1.120407	-1.120407	(488,279)
DIFFERENCE (%)		-5.1%	0.0%	0.0%	-5.1%	-14.0%	-14.0%	-18.4%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A9

ECONOMY ENERGY PURCHASES

INCLUDING LONG TERM PURCHASES
For the Period/Month of: FEBRUARY 2020 REVISED 7_27_2020

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS. COST CENTS/KWH	TOTAL $ FOR FUEL ADJ. (3) X (4) $	COST IF GENERATED (a) CENTS/KWH	(b) TOTAL COST $	FUEL SAVINGS (6)(b)-(5) $

ESTIMATED:

TOTAL							

ACTUAL:

TOTAL							

FOOTNOTE: PURCHASED POWER COSTS INCLUDE CUSTOMER, DEMAND & ENERGY CHARGES TOTALING 0

CURRENT MONTH:							
DIFFERENCE							
DIFFERENCE (%)							
PERIOD TO DATE:							
ACTUAL							
ESTIMATED							
DIFFERENCE							
DIFFERENCE (%)							

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: MARCH 2020 REVISED 7_27_2020

		DOLLARS				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)			0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	418,830	748,610	(329,780)	-44.1%	26,785	27,488	(703)	-2.6%	1.56367	2.72343	(1.15976)	-42.6%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	1,195,756	1,098,553	97,203	8.9%	26,785	27,488	(703)	-2.6%	4.46427	3.99651	0.46776	11.7%
11	Energy Payments to Qualifying Facilities (A8a)	1,079,231	1,422,181	(342,950)	-24.1%	16,023	17,550	(1,527)	-8.7%	6.73560	8.10360	(1.36800)	-16.9%
12	TOTAL COST OF PURCHASED POWER	2,693,817	3,269,344	(575,527)	-17.6%	42,808	45,038	(2,230)	-5.0%	6.29282	7.25911	(0.96629)	-13.3%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					42,808	45,038	(2,230)	-5.0%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	(279,006)	143,590	(422,596)	-76.9%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	2,972,823	3,125,754	(152,931)	-4.9%	42,808	45,038	(2,230)	-5.0%	6.94458	6.94029	0.00429	0.1%
21	Net Unbilled Sales (A4)	(25,461) *	(40,615) *	15,154	-37.3%	(367)	(585)	219	-37.4%	(0.06276)	(0.09469)	0.03193	-33.7%
22	Company Use (A4)	2,807 *	1,943 *	864	44.5%	40	28	12	44.4%	0.00692	0.00453	0.00239	52.8%
23	T & D Losses (A4)	178,337 *	187,527 *	(9,190)	-4.9%	2,568	2,702	(134)	-5.0%	0.43962	0.43720	0.00242	0.6%
24	SYSTEM KWH SALES	2,972,823	3,125,754	(152,931)	-4.9%	40,566	42,893	(2,327)	-5.4%	7.32836	7.28733	0.04103	0.6%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	2,972,823	3,125,754	(152,931)	-4.9%	40,566	42,893	(2,327)	-5.4%	7.32836	7.28733	0.04103	0.6%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	2,972,823	3,125,754	(152,931)	-4.9%	40,566	42,893	(2,327)	-5.4%	7.32836	7.28733	0.04103	0.6%
28	GPIF**												
29	TRUE-UP**	161,204	161,204	0	0.0%	40,566	42,893	(2,327)	-5.4%	0.39739	0.37583	0.02156	5.7%
30	TOTAL JURISDICTIONAL FUEL COST (Excluding GSLD Apportionment)	3,134,027	3,286,958	(152,931)	-4.7%	40,566	42,893	(2,327)	-5.4%	7.72575	7.66316	0.06259	0.8%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									7.85006	7.78646	0.06360	0.8%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.850	7.786	0.064	0.8%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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Company: FLORIDA PUBLIC UTILITIES COMPANY

CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: MARCH 2020 REVISED 7_27_2020

		PERIOD TO DATE DOLLARS				PERIOD TO DATE MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)	0	0	0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	1,732,133	2,282,592	(550,459)	-24.1%	91,737	85,996	5,741	6.7%	1.88815	2.65429	(0.76614)	-28.9%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	3,987,039	3,721,908	265,131	7.1%	91,737	85,996	5,741	6.7%	4.34616	4.32799	0.01817	0.4%
11	Energy Payments to Qualifying Facilities (A8a)	3,246,554	4,077,783	(831,229)	-20.4%	47,422	50,650	(3,228)	-6.4%	6.84615	8.05090	(1.20475)	-15.0%
12	TOTAL COST OF PURCHASED POWER	8,965,726	10,082,283	(1,116,557)	-11.1%	139,159	136,646	2,512	1.8%	6.44281	7.37838	(0.93557)	-12.7%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					139,159	136,646	2,512	1.8%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	(88,952)	390,899	(479,851)	-122.8%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	9,054,678	9,691,384	(636,706)	-6.6%	139,159	136,646	2,512	1.8%	6.50673	7.09231	(0.58558)	-8.3%
21	Net Unbilled Sales (A4)	392,351 *	263,628 *	128,723	48.8%	6,030	3,717	2,313	62.2%	0.30076	0.20257	0.09819	48.5%
22	Company Use (A4)	7,007 *	6,185 *	822	13.3%	108	87	20	23.5%	0.00537	0.00475	0.00062	13.1%
23	T & D Losses (A4)	167,093 *	191,634 *	(24,541)	-12.8%	2,568	2,702	(134)	-5.0%	0.12809	0.14725	(0.01916)	-13.0%
24	SYSTEM KWH SALES	9,054,678	9,691,384	(636,706)	-6.6%	130,453	130,140	313	0.2%	6.94095	7.44688	(0.50593)	-6.8%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	9,054,678	9,691,384	(636,706)	-6.6%	130,453	130,140	313	0.2%	6.94095	7.44688	(0.50593)	-6.8%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	9,054,678	9,691,384	(636,706)	-6.6%	130,453	130,140	313	0.2%	6.94095	7.44688	(0.50593)	-6.8%
28	GPIF**												
29	TRUE-UP**	483,612	483,612	(0)	0.0%	130,453	130,140	313	0.2%	0.37072	0.37161	(0.00089)	-0.2%
30	TOTAL JURISDICTIONAL FUEL COST	9,538,290	10,174,996	(636,706)	-6.3%	130,453	130,140	313	0.2%	7.31167	7.81850	(0.50683)	-6.5%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									7.42931	7.94430	(0.51499)	-6.5%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.429	7.944	(0.515)	-6.5%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: MARCH 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. Fuel Cost & Net Power Transactions								
1. Fuel Cost of System Net Generation	$ 0	$ 0	$ 0	0.0%	$ 0	$ 0	$ 0	0.0%
1a. Fuel Related Transactions (Nuclear Fuel Disposal)								
2. Fuel Cost of Power Sold								
3. Fuel Cost of Purchased Power	418,830	748,610	(329,780)	-44.1%	1,732,133	2,282,592	(550,459)	-24.1%
3a. Demand & Non Fuel Cost of Purchased Power	1,195,756	1,098,553	97,203	8.9%	3,987,039	3,721,908	265,131	7.1%
3b. Energy Payments to Qualifying Facilities	1,079,231	1,422,181	(342,950)	-24.1%	3,246,554	4,077,783	(831,229)	-20.4%
4. Energy Cost of Economy Purchases								
5. Total Fuel & Net Power Transactions	2,693,817	3,269,344	(575,527)	-17.6%	8,965,726	10,082,283	(1,116,557)	-11.1%
6. Adjustments to Fuel Cost (Describe Items)								
6a. Special Meetings - Fuel Market Issue	994	19,300	(18,306)	-94.9%	28,197	55,000	(26,803)	-48.7%
7. Adjusted Total Fuel & Net Power Transactions	2,694,810	3,288,644	(593,833)	-18.1%	8,993,923	10,137,283	(1,143,360)	-11.3%
8. Less Apportionment To GSLD Customers	(279,006)	143,590	(422,596)	-294.3%	(88,952)	390,899	(479,851)	-122.8%
9. Net Total Fuel & Power Transactions To Other Classes	$ 2,973,816	$ 3,145,054	$ (171,237)	-5.4%	$ 9,082,875	$ 9,746,384	$ (663,509)	-6.8%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: MARCH 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
B. Sales Revenues (Exclude Revenue Taxes & Franchise Taxes)								
1. Jurisidictional Sales Revenue (Excluding GSLD)	$	$	$		$	$	$	
a. Base Fuel Revenue								
b. Fuel Recovery Revenue	2,956,612	3,204,952	(248,340)	-7.8%	9,288,757	9,707,611	(418,854)	-4.3%
c. Jurisidictional Fuel Revenue	2,956,612	3,204,952	(248,340)	-7.8%	9,288,757	9,707,611	(418,854)	-4.3%
d. Non Fuel Revenue	1,768,292	1,728,159	40,134	2.3%	6,177,395	5,994,125	183,269	3.1%
e. Total Jurisdictional Sales Revenue	4,724,904	4,933,110	(208,206)	-4.2%	15,466,152	15,701,736	(235,584)	-1.5%
2. Non Jurisdictional Sales Revenue	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales Revenue (Excluding GSLD)	$ 4,724,904	$ 4,933,110	$ (208,206)	-4.2%	$ 15,466,152	$ 15,701,736	$ (235,584)	-1.5%
C. KWH Sales (Excluding GSLD)								
1. Jurisdictional Sales KWH	40,484,336	41,243,143	(758,807)	-1.8%	129,716,031	125,619,330	4,096,701	3.3%
2. Non Jurisdictional Sales	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales	40,484,336	41,243,143	(758,807)	-1.8%	129,716,031	125,619,330	4,096,701	3.3%
4. Jurisdictional Sales % of Total KWH Sales	100.00%	100.00%	0.00%	0.0%	100.00%	100.00%	0.00%	0.0%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: MARCH 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. True-up Calculation (Excluding GSLD)								
1. Jurisdictional Fuel Rev. (line B-1c)	$ 2,956,612	$ 3,204,952	$ (248,340)	-7.8%	$ 9,288,757	$ 9,707,611	$ (418,854)	-4.3%
2. Fuel Adjustment Not Applicable								
a. True-up Provision	161,204	161,204	0	0.0%	483,612	483,612	(0)	0.0%
b. Incentive Provision								
c. Transition Adjustment (Regulatory Tax Refund)							0	0.0%
3. Jurisdictional Fuel Revenue Applicable to Period	2,795,408	3,043,748	(248,340)	-8.2%	8,805,145	9,223,998	(418,853)	-4.5%
4. Adjusted Total Fuel & Net Power Transaction (Line A-7)	2,973,816	3,145,054	(171,237)	-5.4%	9,082,875	9,746,384	(663,509)	-6.8%
5. Jurisdictional Sales % of Total KWH Sales (Line C-4)	100%	100%	0.00%	0.0%	N/A	N/A		
6. Jurisdictional Total Fuel & Net Power Transactions (Line D-4 x Line D-5 x *)	2,973,816	3,145,054	(171,238)	-5.4%	9,082,875	9,746,384	(663,509)	-6.8%
7. True-up Provision for the Month Over/Under Collection (Line D-3 - Line D-6)	(178,408)	(101,306)	(77,102)	76.1%	(277,730)	(522,386)	244,655	-46.8%
8. Interest Provision for the Month	(5,342)	(4,290)	(1,052)	24.5%	(16,054)	(11,044)	(5,010)	45.4%
9. True-up & Inst. Provision Beg. of Month	(3,739,974)	561,200	(4,301,174)	-766.4%	(3,952,348)	666,626	(4,618,974)	-692.9%
9a. Deferred True-up Beginning of Period								
10. True-up Collected (Refunded)	161,204	161,204	0	0.0%	483,612	483,612	(0)	0.0%
11. End of Period - Total Net True-up (Lines D7 through D10)	$ (3,762,520)	$ 616,808	$ (4,379,328)	-710.0%	$ (3,762,520)	$ 616,808	$ (4,379,328)	-710.0%

* Jurisdictional Loss Multiplier

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: MARCH 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
E. Interest Provision (Excluding GSLD)							--	--
1. Beginning True-up Amount (lines D-9 + 9a)	$ (3,739,974)	$ 561,200	$ (4,301,174)	-766.4%	N/A	N/A	--	--
2. Ending True-up Amount Before Interest	(3,757,178)	621,098	(4,378,276)	-704.9%	N/A	N/A	--	--
(line D-7 + Lines D-9 + 9a + D-10)					N/A	N/A	--	--
3. Total of Beginning & Ending True-up Amount	(7,497,153)	1,182,298	(8,679,451)	-734.1%	N/A	N/A	--	--
4. Average True-up Amount (50% of Line E-3)	$ (3,748,576)	$ 591,149	$ (4,339,725)	-734.1%	N/A	N/A	--	--
5. Interest Rate - First Day Reporting Business Month	1.5100%	N/A	--	--	N/A	N/A	--	--
6. Interest Rate - First Day Subsequent Business Month	1.9100%	N/A	--	--	N/A	N/A	--	--
7. Total (Line E-5 + Line E-6)	3.4200%	N/A	--	--	N/A	N/A	--	--
8. Average Interest Rate (50% of Line E-7)	1.7100%	N/A	--	--	N/A	N/A	--	--
9. Monthly Average Interest Rate (Line E-8 / 12)	0.1425%	N/A	--	--	N/A	N/A	--	--
10. Interest Provision (Line E-4 x Line E-9)	(5,342)	N/A	--	--	N/A	N/A	--	--

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

Schedule A4

ELECTRIC ENERGY ACCOUNT
Month of: MARCH 2020 REVISED 7_27_2020

			CURRENT MONTH				PERIOD TO DATE			
			ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	(MWH)									
1	System Net Generation		0	0	0	0.00%	0	0	0	0.00%
2	Power Sold									
3	Inadvertent Interchange Delivered - NET									
4	Purchased Power		26,785	27,488	(703)	-2.56%	26,785	27,488	(703)	-2.56%
4a	Energy Purchased For Qualifying Facilities		16,023	17,550	(1,527)	-8.70%	16,023	17,550	(1,527)	-8.70%
5	Economy Purchases									
6	Inadvertent Interchange Received - NET									
7	Net Energy for Load		42,808	45,038	(2,230)	-4.95%	42,808	45,038	(2,230)	-4.95%
8	Sales (Billed)		40,566	42,893	(2,327)	-5.43%	130,453	130,140	313	0.24%
8a	Unbilled Sales Prior Month (Period)									
8b	Unbilled Sales Current Month (Period)									
9	Company Use		40	28	12	44.35%	108	87	20	23.50%
10	T&D Losses Estimated @	0.06	2,568	2,702	(134)	-4.96%	2,568	2,702	(134)	-4.96%
11	Unaccounted for Energy (estimated)		(367)	(585)	219	-37.35%	(90,321)	(87,891)	(2,430)	2.76%
12										
13	% Company Use to NEL		0.09%	0.06%	0.03%	50.00%	0.25%	0.19%	0.06%	31.58%
14	% T&D Losses to NEL		6.00%	6.00%	0.00%	0.00%	6.00%	6.00%	0.00%	0.00%
15	% Unaccounted for Energy to NEL		-0.86%	-1.30%	0.44%	-33.85%	-210.99%	-195.15%	-15.84%	8.12%
	($)									
16	Fuel Cost of Sys Net Gen		-	-	-	0	-	-	-	0
16a	Fuel Related Transactions									
16b	Adjustments to Fuel Cost									
17	Fuel Cost of Power Sold									
18	Fuel Cost of Purchased Power		418,830	748,610	(329,780)	-44.05%	1,732,133	2,282,592	(550,459)	-24.12%
18a	Demand & Non Fuel Cost of Pur Power		1,195,756	1,098,553	97,203	8.85%	3,987,039	3,721,908	265,131	7.12%
18b	Energy Payments To Qualifying Facilities		1,079,231	1,422,181	(342,950)	-24.11%	3,246,554	4,077,783	(831,229)	-20.38%
19	Energy Cost of Economy Purch.									
20	Total Fuel & Net Power Transactions		2,693,817	3,269,344	(575,527)	-17.60%	8,965,726	10,082,283	(1,116,557)	-11.07%
	(Cents/KWH)									
21	Fuel Cost of Sys Net Gen									
21a	Fuel Related Transactions									
22	Fuel Cost of Power Sold									
23	Fuel Cost of Purchased Power		1.564	2.723	(1.159)	-42.56%	6.467	8.304	(1.837)	-22.12%
23a	Demand & Non Fuel Cost of Pur Power		4.464	3.997	0.467	11.68%	14.885	13.540	1.345	9.93%
23b	Energy Payments To Qualifying Facilities		6.736	8.104	(1.368)	-16.88%	20.262	23.235	(2.973)	-12.80%
24	Energy Cost of Economy Purch.									
25	Total Fuel & Net Power Transactions		6.293	7.259	(0.966)	-13.31%	20.944	22.386	(1.442)	-6.44%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A8

PURCHASED POWER

(Exclusive of Economy Energy Purchases)
For the Period/Month of: MARCH 2020 REVISED 7_27_2020

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) KWH FOR OTHER UTILITIES (000)	(5) KWH FOR INTERRUP-TIBLE (000)	(6) KWH FOR FIRM (000)	(7) CENTS/KWH (a) FUEL COST	(7) CENTS/KWH (b) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
ESTIMATED:								
FPL AND GULF/SOUTHERN	MS	27,488			27,488	2.723426	6.719937	748,610
TOTAL		27,488	0	0	27,488	2.723426	6.719937	748,610
ACTUAL:								
FPL	MS	5,271			5,271	1.004800	10.064162	52,963
GULF/SOUTHERN		21,514			21,514	1.700598	5.039061	365,867
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
TOTAL		26,785	0	0	26,785	2.705398	10.064162	418,830
CURRENT MONTH:								
DIFFERENCE		(703)	0	0	(703)	(0.018028)	3.34423	(329,780)
DIFFERENCE (%)		-2.6%	0.0%	0.0%	-2.6%	-0.7%	49.8%	-44.1%
PERIOD TO DATE:								
ACTUAL	MS	91,737			91,737	1.888151	1.988151	1,732,133
ESTIMATED	MS	85,996			85,996	2.654291	2.754291	2,282,592
DIFFERENCE		5,741	0	0	5,741	(0.766140)	-0.76614	(550,459)
DIFFERENCE (%)		6.7%	0.0%	0.0%	6.7%	-28.9%	-27.8%	-24.1%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A8a

ENERGY PAYMENT TO QUALIFYING FACILITIES

For the Period/Month of: MARCH 2020 REVISED 7_27_2020

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) KWH FOR OTHER UTILITIES (000)	(5) KWH FOR INTERRUP-TIBLE (000)	(6) KWH FOR FIRM (000)	(7) CENTS/KWH (a) FUEL COST	(7) CENTS/KWH (b) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
ESTIMATED:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		17,550			17,550	8.103595	8.103595	1,422,181
TOTAL		17,550	0	0	17,550	8.103595	8.103595	1,422,181
ACTUAL:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		16,023			16,023	6.735601	6.735601	1,079,231
TOTAL		16,023	0	0	16,023	6.735601	6.735601	1,079,231
CURRENT MONTH:								
DIFFERENCE		(1,527)	0	0	(1,527)	-1.367994	-1.367994	(342,950)
DIFFERENCE (%)		-8.7%	0.0%	0.0%	-8.7%	-16.9%	-16.9%	-24.1%
PERIOD TO DATE:								
ACTUAL	MS	47,422			47,422	6.846148	6.846148	3,246,554
ESTIMATED	MS	50,650			50,650	8.050904	8.050904	4,077,783
DIFFERENCE		(3,228)	0	0	(3,228)	-1.204756	-1.204756	(831,229)
DIFFERENCE (%)		-6.4%	0.0%	0.0%	-6.4%	-15.0%	-15.0%	-20.4%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A9

ECONOMY ENERGY PURCHASES

INCLUDING LONG TERM PURCHASES
For the Period/Month of: MARCH 2020 REVISED 7_27_2020

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS. COST CENTS/KWH	TOTAL $ FOR FUEL ADJ. (3) X (4) $	COST IF GENERATED		FUEL SAVINGS (6)(b)-(5) $
					(a) CENTS/KWH	(b) TOTAL COST $	
ESTIMATED:							
TOTAL							
ACTUAL:							
TOTAL							

FOOTNOTE: PURCHASED POWER COSTS INCLUDE CUSTOMER, DEMAND & ENERGY CHARGES TOTALING 0

CURRENT MONTH:							
DIFFERENCE							
DIFFERENCE (%)							
PERIOD TO DATE:							
ACTUAL							
ESTIMATED							
DIFFERENCE							
DIFFERENCE (%)							

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: APRIL 2020 REVISED 7_27_2020

		DOLLARS				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)			0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	440,517	850,467	(409,950)	-48.2%	27,318	29,738	(2,420)	-8.1%	1.61255	2.85986	(1.24731)	-43.6%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	1,251,700	953,772	297,928	31.2%	27,318	29,738	(2,420)	-8.1%	4.58196	3.20724	1.37472	42.9%
11	Energy Payments to Qualifying Facilities (A8a)	1,006,956	1,315,033	(308,077)	-23.4%	15,176	16,200	(1,024)	-6.3%	6.63515	8.11749	(1.48234)	-18.3%
12	TOTAL COST OF PURCHASED POWER	2,699,173	3,119,272	(420,100)	-13.5%	42,494	45,938	(3,444)	-7.5%	6.35188	6.79017	(0.43829)	-6.5%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					42,494	45,938	(3,444)	-7.5%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	20,204	101,701	(81,497)	-53.9%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	2,678,969	3,017,571	(338,603)	-11.2%	42,494	45,938	(3,444)	-7.5%	6.30433	6.56878	(0.26445)	-4.0%
21	Net Unbilled Sales (A4)	(160,932) *	(39,437) *	(121,495)	308.1%	(2,553)	(600)	(1,952)	325.2%	(0.37906)	(0.09014)	(0.28892)	320.5%
22	Company Use (A4)	2,572 *	2,065 *	507	24.6%	41	31	9	29.8%	0.00606	0.00472	0.00134	28.4%
23	T & D Losses (A4)	160,760 *	181,036 *	(20,276)	-11.2%	2,550	2,756	(206)	-7.5%	0.37865	0.41379	(0.03514)	-8.5%
24	SYSTEM KWH SALES	2,678,969	3,017,571	(338,603)	-11.2%	42,456	43,751	(1,295)	-3.0%	6.30998	6.89715	(0.58717)	-8.5%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	2,678,969	3,017,571	(338,603)	-11.2%	42,456	43,751	(1,295)	-3.0%	6.30998	6.89715	(0.58717)	-8.5%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	2,678,969	3,017,571	(338,602)	-11.2%	42,456	43,751	(1,295)	-3.0%	6.30998	6.89715	(0.58717)	-8.5%
28	GPIF**												
29	TRUE-UP**	161,204	161,204	0	0.0%	42,456	43,751	(1,295)	-3.0%	0.37970	0.36846	0.01124	3.1%
30	TOTAL JURISDICTIONAL FUEL COST (Excluding GSLD Apportionment)	2,840,173	3,178,775	(338,602)	-10.7%	42,456	43,751	(1,295)	-3.0%	6.68969	7.26561	(0.57592)	-7.9%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									6.79733	7.38251	(0.58518)	-7.9%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									6.797	7.383	(0.586)	-7.9%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: APRIL 2020 REVISED 7_27_2020

		PERIOD TO DATE		DOLLARS		PERIOD TO DATE		MWH		CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)	0	0	0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	2,172,650	3,133,059	(960,409)	-30.7%	119,055	115,734	3,321	2.9%	1.82491	2.70711	(0.88220)	-32.6%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	5,238,739	4,675,680	563,059	12.0%	119,055	115,734	3,321	2.9%	4.40027	4.04001	0.36026	8.9%
11	Energy Payments to Qualifying Facilities (A8a)	4,253,510	5,392,816	(1,139,306)	-21.1%	62,598	66,850	(4,252)	-6.4%	6.79499	8.06704	(1.27205)	-15.8%
12	TOTAL COST OF PURCHASED POWER	11,664,899	13,201,555	(1,536,656)	-11.6%	181,653	182,584	(932)	-0.5%	6.42154	7.23039	(0.80885)	-11.2%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					181,653	182,584	(932)	-0.5%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	(68,748)	492,600	(561,348)	-114.0%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	11,733,647	12,708,956	(975,309)	-7.7%	181,653	182,584	(932)	-0.5%	6.45939	6.96059	(0.50120)	-7.2%
21	Net Unbilled Sales (A4)	(148,811) *	(165,681) *	16,870	-10.2%	(2,304)	(2,380)	76	-3.2%	(0.08606)	(0.09528)	0.00922	-9.7%
22	Company Use (A4)	9,591 *	8,258 *	1,333	16.1%	148	119	30	25.2%	0.00555	0.00475	0.00080	16.8%
23	T & D Losses (A4)	704,009 *	762,533 *	(58,524)	-7.7%	10,899	10,955	(56)	-0.5%	0.40716	0.43851	(0.03135)	-7.2%
24	SYSTEM KWH SALES	11,733,647	12,708,956	(975,309)	-7.7%	172,909	173,891	(982)	-0.6%	6.78604	7.30857	(0.52253)	-7.2%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	11,733,647	12,708,956	(975,309)	-7.7%	172,909	173,891	(982)	-0.6%	6.78604	7.30857	(0.52253)	-7.2%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	11,733,647	12,708,956	(975,309)	-7.7%	172,909	173,891	(982)	-0.6%	6.78604	7.30857	(0.52253)	-7.2%
28	GPIF**												
29	TRUE-UP**	644,816	644,816	(0)	0.0%	172,909	173,891	(982)	-0.6%	0.37292	0.37082	0.00210	0.6%
30	TOTAL JURISDICTIONAL FUEL COST	12,378,463	13,353,772	(975,309)	-7.3%	172,909	173,891	(982)	-0.6%	7.15895	7.67939	(0.52044)	-6.8%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									7.27414	7.80295	(0.52881)	-6.8%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.274	7.803	(0.529)	-6.8%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

SCHEDULE A2
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Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: APRIL 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. Fuel Cost & Net Power Transactions								
1. Fuel Cost of System Net Generation	$ 0	$ 0	$ 0	0.0%	$ 0	$ 0	$ 0	0.0%
1a. Fuel Related Transactions (Nuclear Fuel Disposal)								
2. Fuel Cost of Power Sold								
3. Fuel Cost of Purchased Power	440,517	850,467	(409,950)	-48.2%	2,172,650	3,133,059	(960,409)	-30.7%
3a. Demand & Non Fuel Cost of Purchased Power	1,251,700	953,772	297,928	31.2%	5,238,739	4,675,680	563,059	12.0%
3b. Energy Payments to Qualifying Facilities	1,006,956	1,315,033	(308,077)	-23.4%	4,253,510	5,392,816	(1,139,306)	-21.1%
4. Energy Cost of Economy Purchases								
5. Total Fuel & Net Power Transactions	2,699,173	3,119,272	(420,100)	-13.5%	11,664,899	13,201,555	(1,536,656)	-11.6%
6. Adjustments to Fuel Cost (Describe Items)								
6a. Special Meetings - Fuel Market Issue	6,460	17,850	(11,390)	-63.8%	34,657	72,850	(38,193)	-52.4%
7. Adjusted Total Fuel & Net Power Transactions	2,705,633	3,137,122	(431,489)	-13.8%	11,699,556	13,274,405	(1,574,849)	-11.9%
8. Less Apportionment To GSLD Customers	20,204	101,701	(81,497)	-80.1%	(68,748)	492,600	(561,348)	-114.0%
9. Net Total Fuel & Power Transactions To Other Classes	$ 2,685,429	$ 3,035,421	$ (349,992)	-11.5%	$ 11,768,304	$ 12,781,805	$ (1,013,501)	-7.9%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: APRIL 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
B. Sales Revenues (Exclude Revenue Taxes & Franchise Taxes)								
1. Jurisidictional Sales Revenue (Excluding GSLD)	$	$	$		$	$	$	
a. Base Fuel Revenue								
b. Fuel Recovery Revenue	3,107,265	3,270,246	(162,981)	-5.0%	12,396,022	12,977,856	(581,834)	-4.5%
c. Jurisidictional Fuel Revenue	3,107,265	3,270,246	(162,981)	-5.0%	12,396,022	12,977,856	(581,834)	-4.5%
d. Non Fuel Revenue	2,019,631	1,892,493	127,138	6.7%	8,197,025	7,886,618	310,407	3.9%
e. Total Jurisdictional Sales Revenue	5,126,896	5,162,738	(35,843)	-0.7%	20,593,047	20,864,474	(271,427)	-1.3%
2. Non Jurisdictional Sales Revenue	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales Revenue (Excluding GSLD)	$ 5,126,896	$ 5,162,738	$ (35,843)	-0.7%	$ 20,593,047	$ 20,864,474	$ (271,427)	-1.3%
C. KWH Sales (Excluding GSLD)								
1. Jurisdictional Sales KWH	42,183,602	42,660,545	(476,943)	-1.1%	171,899,633	168,279,875	3,619,758	2.2%
2. Non Jurisdictional Sales	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales	42,183,602	42,660,545	(476,943)	-1.1%	171,899,633	168,279,875	3,619,758	2.2%
4. Jurisdictional Sales % of Total KWH Sales	100.00%	100.00%	0.00%	0.0%	100.00%	100.00%	0.00%	0.0%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: APRIL 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. True-up Calculation (Excluding GSLD)								
1. Jurisdictional Fuel Rev. (line B-1c)	$ 3,107,265	$ 3,270,246	$ (162,981)	-5.0%	$ 12,396,022	$ 12,977,856	$ (581,834)	-4.5%
2. Fuel Adjustment Not Applicable								
a. True-up Provision	161,204	161,204	0	0.0%	644,816	644,816	(0)	0.0%
b. Incentive Provision								
c. Transition Adjustment (Regulatory Tax Refund)							0	0.0%
3. Jurisdictional Fuel Revenue Applicable to Period	2,946,061	3,109,042	(162,981)	-5.2%	11,751,206	12,333,040	(581,834)	-4.7%
4. Adjusted Total Fuel & Net Power Transaction (Line A-7)	2,685,429	3,035,421	(349,992)	-11.5%	11,768,304	12,781,805	(1,013,501)	-7.9%
5. Jurisdictional Sales % of Total KWH Sales (Line C-4)	100%	100%	0.00%	0.0%	N/A	N/A		
6. Jurisdictional Total Fuel & Net Power Transactions (Line D-4 x Line D-5 x *)	2,685,429	3,035,421	(349,992)	-11.5%	11,768,304	12,781,805	(1,013,501)	-7.9%
7. True-up Provision for the Month Over/Under Collection (Line D-3 - Line D-6)	260,632	73,621	187,011	254.0%	(17,098)	(448,766)	431,667	-96.2%
8. Interest Provision for the Month	(3,154)	(4,252)	1,098	-25.8%	(19,208)	(15,296)	(3,912)	25.6%
9. True-up & Inst. Provision Beg. of Month	(3,762,520)	616,808	(4,379,328)	-710.0%	(3,952,348)	666,626	(4,618,974)	-692.9%
9a. Deferred True-up Beginning of Period								
10. True-up Collected (Refunded)	161,204	161,204	0	0.0%	644,816	644,816	(0)	0.0%
11. End of Period - Total Net True-up (Lines D7 through D10)	$ (3,343,838)	$ 847,381	$ (4,191,219)	-494.6%	$ (3,343,838)	$ 847,381	$ (4,191,219)	-494.6%

* Jurisdictional Loss Multiplier

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: APRIL 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
E. Interest Provision (Excluding GSLD)							--	--
1. Beginning True-up Amount (lines D-9 + 9a)	$ (3,762,520)	$ 616,808	$ (4,379,328)	-710.0%	N/A	N/A	--	--
2. Ending True-up Amount Before Interest	(3,340,684)	851,633	(4,192,317)	-492.3%	N/A	N/A	--	--
(line D-7 + Lines D-9 + 9a + D-10)					N/A	N/A	--	--
3. Total of Beginning & Ending True-up Amount	(7,103,204)	1,468,441	(8,571,645)	-583.7%	N/A	N/A	--	--
4. Average True-up Amount (50% of Line E-3)	$ (3,551,602)	$ 734,220	$ (4,285,822)	-583.7%	N/A	N/A	--	--
5. Interest Rate - First Day Reporting Business Month	1.9100%	N/A	--	--	N/A	N/A	--	--
6. Interest Rate - First Day Subsequent Business Month	0.2200%	N/A	--	--	N/A	N/A	--	--
7. Total (Line E-5 + Line E-6)	2.1300%	N/A	--	--	N/A	N/A	--	--
8. Average Interest Rate (50% of Line E-7)	1.0650%	N/A	--	--	N/A	N/A	--	--
9. Monthly Average Interest Rate (Line E-8 / 12)	0.0888%	N/A	--	--	N/A	N/A	--	--
10. Interest Provision (Line E-4 x Line E-9)	(3,154)	N/A	--	--	N/A	N/A	--	--

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

Schedule A4

ELECTRIC ENERGY ACCOUNT
Month of: APRIL 2020 REVISED 7_27_2020

			CURRENT MONTH				PERIOD TO DATE			
			ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	(MWH)									
1	System Net Generation		0	0	0	0.00%	0	0	0	0.00%
2	Power Sold									
3	Inadvertent Interchange Delivered - NET									
4	Purchased Power		27,318	29,738	(2,420)	-8.14%	119,055	115,734	3,321	2.87%
4a	Energy Purchased For Qualifying Facilities		15,176	16,200	(1,024)	-6.32%	62,598	66,850	(4,252)	-6.36%
5	Economy Purchases									
6	Inadvertent Interchange Received - NET									
7	Net Energy for Load		42,494	45,938	(3,444)	-7.50%	181,653	182,584	(932)	-0.51%
8	Sales (Billed)		42,456	43,751	(1,295)	-2.96%	172,909	173,891	(982)	-0.56%
8a	Unbilled Sales Prior Month (Period)									
8b	Unbilled Sales Current Month (Period)									
9	Company Use		41	31	9	29.77%	148	119	30	25.16%
10	T&D Losses Estimated @	0.06	2,550	2,756	(206)	-7.47%	10,899	10,955	(56)	-0.51%
11	Unaccounted for Energy (estimated)		(2,553)	(600)	(1,952)	325.20%	(2,304)	(2,380)	76	-3.21%
12										
13	% Company Use to NEL		0.10%	0.07%	0.03%	42.86%	0.08%	0.06%	0.02%	33.33%
14	% T&D Losses to NEL		6.00%	6.00%	0.00%	0.00%	6.00%	6.00%	0.00%	0.00%
15	% Unaccounted for Energy to NEL		-6.01%	-1.31%	-4.70%	358.78%	-1.27%	-1.30%	0.03%	-2.31%
	($)									
16	Fuel Cost of Sys Net Gen		-	-	-	0	-	-	-	0
16a	Fuel Related Transactions									
16b	Adjustments to Fuel Cost									
17	Fuel Cost of Power Sold									
18	Fuel Cost of Purchased Power		440,517	850,467	(409,950)	-48.20%	2,172,650	3,133,059	(960,409)	-30.65%
18a	Demand & Non Fuel Cost of Pur Power		1,251,700	953,772	297,928	31.24%	5,238,739	4,675,680	563,059	12.04%
18b	Energy Payments To Qualifying Facilities		1,006,956	1,315,033	(308,077)	-23.43%	4,253,510	5,392,816	(1,139,306)	-21.13%
19	Energy Cost of Economy Purch.									
20	Total Fuel & Net Power Transactions		2,699,173	3,119,272	(420,100)	-13.47%	11,664,899	13,201,555	(1,536,656)	-11.64%
	(Cents/KWH)									
21	Fuel Cost of Sys Net Gen									
21a	Fuel Related Transactions									
22	Fuel Cost of Power Sold									
23	Fuel Cost of Purchased Power		1.613	2.860	(1.247)	-43.60%	1.825	2.707	(0.882)	-32.58%
23a	Demand & Non Fuel Cost of Pur Power		4.582	3.207	1.375	42.87%	4.400	4.040	0.360	8.91%
23b	Energy Payments To Qualifying Facilities		6.635	8.117	(1.482)	-18.26%	6.795	8.067	(1.272)	-15.77%
24	Energy Cost of Economy Purch.									
25	Total Fuel & Net Power Transactions		6.352	6.790	(0.438)	-6.45%	6.422	7.230	(0.808)	-11.18%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A8

PURCHASED POWER

(Exclusive of Economy Energy Purchases)
For the Period/Month of: APRIL 2020 REVISED 7_27_2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR OTHER UTILITIES (000)	KWH FOR INTERRUP-TIBLE (000)	KWH FOR FIRM (000)	CENTS/KWH (a) FUEL COST	(b) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
ESTIMATED:								
FPL AND GULF/SOUTHERN	MS	29,738			29,738	2.859859	6.067103	850,467
TOTAL		29,738	0	0	29,738	2.859859	6.067103	850,467
ACTUAL:								
FPL	MS	7,497			7,497	1.517140	8.452514	113,740
GULF/SOUTHERN		19,821			19,821	1.648638	5.340455	326,777
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
TOTAL		27,318	0	0	27,318	3.165778	8.452514	440,517
CURRENT MONTH:								
DIFFERENCE		(2,420)	0	0	(2,420)	0.305919	2.38541	(409,950)
DIFFERENCE (%)		-8.1%	0.0%	0.0%	-8.1%	10.7%	39.3%	-48.2%
PERIOD TO DATE:								
ACTUAL	MS	119,055			119,055	1.824913	1.924913	2,172,650
ESTIMATED	MS	115,734			115,734	2.707112	2.807112	3,133,059
DIFFERENCE		3,321	0	0	3,321	(0.882199)	-0.882199	(960,409)
DIFFERENCE (%)		2.9%	0.0%	0.0%	2.9%	-32.6%	-31.4%	-30.7%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A8a

ENERGY PAYMENT TO QUALIFYING FACILITIES

For the Period/Month of: APRIL 2020 REVISED 7_27_2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR OTHER UTILITIES (000)	KWH FOR INTERRUP-TIBLE (000)	KWH FOR FIRM (000)	CENTS/KWH		TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
						(a) FUEL COST	(b) TOTAL COST	
ESTIMATED:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		16,200			16,200	8.117488	8.117488	1,315,033
TOTAL		16,200	0	0	16,200	8.117488	8.117488	1,315,033
ACTUAL:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		15,176			15,176	6.635154	6.635154	1,006,956
TOTAL		15,176	0	0	15,176	6.635154	6.635154	1,006,956
CURRENT MONTH:								
DIFFERENCE		(1,024)	0	0	(1,024)	-1.482334	-1.482334	(308,077)
DIFFERENCE (%)		-6.3%	0.0%	0.0%	-6.3%	-18.3%	-18.3%	-23.4%
PERIOD TO DATE:								
ACTUAL	MS	62,598			62,598	6.794995	6.794995	4,253,510
ESTIMATED	MS	66,850			66,850	8.067040	8.067040	5,392,816
DIFFERENCE		(4,252)	0	0	(4,252)	-1.272045	-1.272045	(1,139,306)
DIFFERENCE (%)		-6.4%	0.0%	0.0%	-6.4%	-15.8%	-15.8%	-21.1%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A9

ECONOMY ENERGY PURCHASES

INCLUDING LONG TERM PURCHASES
For the Period/Month of: APRIL 2020 REVISED 7_27_2020

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS. COST CENTS/KWH	TOTAL $ FOR FUEL ADJ. (3) X (4) $	COST IF GENERATED		FUEL SAVINGS (6)(b)-(5) $
					(a) CENTS/KWH	(b) TOTAL COST $	
ESTIMATED:							
TOTAL							
ACTUAL:							
TOTAL							

FOOTNOTE: PURCHASED POWER COSTS INCLUDE CUSTOMER, DEMAND & ENERGY CHARGES TOTALING 0

CURRENT MONTH:							
DIFFERENCE							
DIFFERENCE (%)							
PERIOD TO DATE:							
ACTUAL							
ESTIMATED							
DIFFERENCE							
DIFFERENCE (%)							

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: MAY 2020 REVISED 7_27_2020

SCHEDULE A1
PAGE 1 OF 2

		DOLLARS				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)			0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	827,495	865,282	(37,787)	-4.4%	38,547	32,694	5,853	17.9%	2.14672	2.64661	(0.49989)	-18.9%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	1,316,848	1,160,739	156,109	13.5%	38,547	32,694	5,853	17.9%	3.41621	3.55031	(0.13410)	-3.8%
11	Energy Payments to Qualifying Facilities (A8a)	1,015,294	1,440,951	(425,657)	-29.5%	15,055	17,800	(2,745)	-15.4%	6.74374	8.09523	(1.35149)	-16.7%
12	TOTAL COST OF PURCHASED POWER	3,159,637	3,466,972	(307,335)	-8.9%	53,602	50,494	3,108	6.2%	5.89459	6.86610	(0.97151)	-14.2%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					53,602	50,494	3,108	6.2%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	41,419	83,750	(42,331)	-29.3%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	3,118,218	3,383,222	(265,004)	-7.8%	53,602	50,494	3,108	6.2%	5.81731	6.70024	(0.88293)	-13.2%
21	Net Unbilled Sales (A4)	423,428 *	(44,258) *	467,686	-1056.7%	7,279	(661)	7,939	-1201.9%	0.98316	(0.09203)	1.07519	-1168.3%
22	Company Use (A4)	2,304 *	2,317 *	(13)	-0.6%	40	35	5	14.6%	0.00535	0.00482	0.00053	11.0%
23	T & D Losses (A4)	187,085 *	203,017 *	(15,932)	-7.9%	3,216	3,030	186	6.1%	0.43439	0.42216	0.01223	2.9%
24	SYSTEM KWH SALES	3,118,218	3,383,222	(265,004)	-7.8%	43,068	48,090	(5,022)	-10.4%	7.24021	7.03519	0.20502	2.9%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	3,118,218	3,383,222	(265,004)	-7.8%	43,068	48,090	(5,022)	-10.4%	7.24021	7.03519	0.20502	2.9%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	3,118,218	3,383,222	(265,004)	-7.8%	43,068	48,090	(5,022)	-10.4%	7.24021	7.03519	0.20502	2.9%
28	GPIF**												
29	TRUE-UP**	161,204	161,204	0	0.0%	43,068	48,090	(5,022)	-10.4%	0.37430	0.33521	0.03909	11.7%
30	TOTAL JURISDICTIONAL FUEL COST (Excluding GSLD Apportionment)	3,279,422	3,544,426	(265,004)	-7.5%	43,068	48,090	(5,022)	-10.4%	7.61452	7.37040	0.24412	3.3%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									7.73704	7.48899	0.24805	3.3%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.737	7.489	0.248	3.3%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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Company: **FLORIDA PUBLIC UTILITIES COMPANY**

CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: MAY 2020 REVISED 7_27_2020

SCHEDULE A1
PAGE 2 OF 2

		PERIOD TO DATE		DOLLARS		PERIOD TO DATE		MWH		CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)	0	0	0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	3,000,145	3,998,341	(998,196)	-25.0%	157,602	148,428	9,174	6.2%	1.90362	2.69378	(0.79016)	-29.3%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	6,555,587	5,836,419	719,168	12.3%	157,602	148,428	9,174	6.2%	4.15958	3.93214	0.22744	5.8%
11	Energy Payments to Qualifying Facilities (A8a)	5,268,804	6,833,767	(1,564,963)	-22.9%	77,653	84,650	(6,997)	-8.3%	6.78506	8.07297	(1.28791)	-16.0%
12	TOTAL COST OF PURCHASED POWER	14,824,536	16,668,527	(1,843,991)	-11.1%	235,255	233,078	2,177	0.9%	6.30147	7.15147	(0.85000)	-11.9%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					235,255	233,078	2,177	0.9%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	(27,329)	576,350	(603,679)	-104.7%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	14,851,865	16,092,178	(1,240,312)	-7.7%	235,255	233,078	2,177	0.9%	6.31309	6.90419	(0.59110)	-8.6%
21	Net Unbilled Sales (A4)	314,074 *	(209,944) *	524,018	-249.6%	4,975	(3,041)	8,016	-263.6%	0.14542	(0.09458)	0.24000	-253.8%
22	Company Use (A4)	11,875 *	10,578 *	1,297	12.3%	188	153	35	22.8%	0.00550	0.00477	0.00073	15.3%
23	T & D Losses (A4)	891,093 *	965,551 *	(74,458)	-7.7%	14,115	13,985	130	0.9%	0.41259	0.43497	(0.02238)	-5.2%
24	SYSTEM KWH SALES	14,851,865	16,092,178	(1,240,312)	-7.7%	215,977	221,981	(6,004)	-2.7%	6.87660	7.24935	(0.37275)	-5.1%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	14,851,865	16,092,178	(1,240,312)	-7.7%	215,977	221,981	(6,004)	-2.7%	6.87660	7.24935	(0.37275)	-5.1%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	14,851,865	16,092,178	(1,240,313)	-7.7%	215,977	221,981	(6,004)	-2.7%	6.87660	7.24935	(0.37275)	-5.1%
28	GPIF**												
29	TRUE-UP**	806,020	806,020	(0)	0.0%	215,977	221,981	(6,004)	-2.7%	0.37320	0.36310	0.01010	2.8%
30	TOTAL JURISDICTIONAL FUEL COST	15,657,885	16,898,198	(1,240,313)	-7.3%	215,977	221,981	(6,004)	-2.7%	7.24979	7.61245	(0.36266)	-4.8%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									7.36644	7.73493	(0.36849)	-4.8%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.366	7.735	(0.369)	-4.8%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: MAY 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. Fuel Cost & Net Power Transactions								
1. Fuel Cost of System Net Generation	$ 0	$ 0	$ 0	0.0%	$ 0	$ 0	$ 0	0.0%
1a. Fuel Related Transactions (Nuclear Fuel Disposal)								
2. Fuel Cost of Power Sold								
3. Fuel Cost of Purchased Power	827,495	865,282	(37,787)	-4.4%	3,000,145	3,998,341	(998,196)	-25.0%
3a. Demand & Non Fuel Cost of Purchased Power	1,316,848	1,160,739	156,109	13.5%	6,555,587	5,836,419	719,168	12.3%
3b. Energy Payments to Qualifying Facilities	1,015,294	1,440,951	(425,657)	-29.5%	5,268,804	6,833,767	(1,564,963)	-22.9%
4. Energy Cost of Economy Purchases								
5. Total Fuel & Net Power Transactions	3,159,637	3,466,972	(307,335)	-8.9%	14,824,536	16,668,527	(1,843,991)	-11.1%
6. Adjustments to Fuel Cost (Describe Items)								
6a. Special Meetings - Fuel Market Issue	14,921	17,850	(2,929)	-16.4%	49,578	90,700	(41,122)	-45.3%
7. Adjusted Total Fuel & Net Power Transactions	3,174,558	3,484,822	(310,264)	-8.9%	14,874,114	16,759,227	(1,885,113)	-11.3%
8. Less Apportionment To GSLD Customers	41,419	83,750	(42,331)	-50.5%	(27,329)	576,350	(603,679)	-104.7%
9. Net Total Fuel & Power Transactions To Other Classes	$ 3,133,139	$ 3,401,072	$ (267,933)	-7.9%	$ 14,901,443	$ 16,182,877	$ (1,281,434)	-7.9%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: MAY 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
B. Sales Revenues (Exclude Revenue Taxes & Franchise Taxes)								
1. Jurisidictional Sales Revenue (Excluding GSLD)	$	$	$		$	$	$	
a. Base Fuel Revenue								
b. Fuel Recovery Revenue	3,221,863	3,600,219	(378,356)	-10.5%	15,617,885	16,578,076	(960,191)	-5.8%
c. Jurisidictional Fuel Revenue	3,221,863	3,600,219	(378,356)	-10.5%	15,617,885	16,578,076	(960,191)	-5.8%
d. Non Fuel Revenue	2,041,462	2,266,167	(224,705)	-9.9%	10,238,487	10,152,785	85,702	0.8%
e. Total Jurisdictional Sales Revenue	5,263,325	5,866,386	(603,061)	-10.3%	25,856,372	26,730,860	(874,488)	-3.3%
2. Non Jurisdictional Sales Revenue	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales Revenue (Excluding GSLD)	$ 5,263,325	$ 5,866,386	$ (603,061)	-10.3%	$ 25,856,372	$ 26,730,860	$ (874,488)	-3.3%
C. KWH Sales (Excluding GSLD)								
1. Jurisdictional Sales KWH	42,944,192	47,289,547	(4,345,355)	-9.2%	214,843,825	215,569,422	(725,597)	-0.3%
2. Non Jurisdictional Sales	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales	42,944,192	47,289,547	(4,345,355)	-9.2%	214,843,825	215,569,422	(725,597)	-0.3%
4. Jurisdictional Sales % of Total KWH Sales	100.00%	100.00%	0.00%	0.0%	100.00%	100.00%	0.00%	0.0%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: MAY 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. True-up Calculation (Excluding GSLD)								
1. Jurisdictional Fuel Rev. (line B-1c)	$ 3,221,863	$ 3,600,219	$ (378,356)	-10.5%	$ 15,617,885	$ 16,578,076	$ (960,191)	-5.8%
2. Fuel Adjustment Not Applicable								
a. True-up Provision	161,204	161,204	0	0.0%	806,020	806,020	(0)	0.0%
b. Incentive Provision								
c. Transition Adjustment (Regulatory Tax Refund)							0	0.0%
3. Jurisdictional Fuel Revenue Applicable to Period	3,060,659	3,439,015	(378,356)	-11.0%	14,811,865	15,772,055	(960,190)	-6.1%
4. Adjusted Total Fuel & Net Power Transaction (Line A-7)	3,133,139	3,401,072	(267,933)	-7.9%	14,901,443	16,182,877	(1,281,434)	-7.9%
5. Jurisdictional Sales % of Total KWH Sales (Line C-4)	100%	100%	0.00%	0.0%	N/A	N/A		
6. Jurisdictional Total Fuel & Net Power Transactions (Line D-4 x Line D-5 x *)	3,133,139	3,401,072	(267,933)	-7.9%	14,901,443	16,182,877	(1,281,434)	-7.9%
7. True-up Provision for the Month Over/Under Collection (Line D-3 - Line D-6)	(72,480)	37,943	(110,423)	-291.0%	(89,578)	(410,822)	321,244	-78.2%
8. Interest Provision for the Month	(455)	(4,031)	3,576	-88.7%	(19,663)	(19,327)	(336)	1.7%
9. True-up & Inst. Provision Beg. of Month	(3,343,838)	847,381	(4,191,219)	-494.6%	(3,952,348)	666,626	(4,618,974)	-692.9%
9a. Deferred True-up Beginning of Period								
10. True-up Collected (Refunded)	161,204	161,204	0	0.0%	806,020	806,020	(0)	0.0%
11. End of Period - Total Net True-up (Lines D7 through D10)	$ (3,255,569)	$ 1,042,497	$ (4,298,066)	-412.3%	$ (3,255,569)	$ 1,042,497	$ (4,298,066)	-412.3%

* Jurisdictional Loss Multiplier

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: MAY 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
E. Interest Provision (Excluding GSLD)							--	--
1. Beginning True-up Amount (lines D-9 + 9a)	$ (3,343,838)	$ 847,381	$ (4,191,219)	-494.6%	N/A	N/A	--	--
2. Ending True-up Amount Before Interest	(3,255,114)	1,046,528	(4,301,642)	-411.0%	N/A	N/A	--	--
(line D-7 + Lines D-9 + 9a + D-10)					N/A	N/A	--	--
3. Total of Beginning & Ending True-up Amount	(6,598,952)	1,893,909	(8,492,861)	-448.4%	N/A	N/A	--	--
4. Average True-up Amount (50% of Line E-3)	$ (3,299,476)	$ 946,955	$ (4,246,431)	-448.4%	N/A	N/A	--	--
5. Interest Rate - First Day Reporting Business Month	0.2200%	N/A	--	--	N/A	N/A	--	--
6. Interest Rate - First Day Subsequent Business Month	0.1100%	N/A	--	--	N/A	N/A	--	--
7. Total (Line E-5 + Line E-6)	0.3300%	N/A	--	--	N/A	N/A	--	--
8. Average Interest Rate (50% of Line E-7)	0.1650%	N/A	--	--	N/A	N/A	--	--
9. Monthly Average Interest Rate (Line E-8 / 12)	0.0138%	N/A	--	--	N/A	N/A	--	--
10. Interest Provision (Line E-4 x Line E-9)	(455)	N/A	--	--	N/A	N/A	--	--

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

Schedule A4

ELECTRIC ENERGY ACCOUNT
Month of: MAY 2020 REVISED 7_27_2020

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	(MWH)								
1	System Net Generation	0	0	0	0.00%	0	0	0	0.00%
2	Power Sold								
3	Inadvertent Interchange Delivered - NET								
4	Purchased Power	38,547	32,694	5,853	17.90%	157,602	148,428	9,174	6.18%
4a	Energy Purchased For Qualifying Facilities	15,055	17,800	(2,745)	-15.42%	77,653	84,650	(6,997)	-8.27%
5	Economy Purchases								
6	Inadvertent Interchange Received - NET								
7	Net Energy for Load	53,602	50,494	3,108	6.16%	235,255	233,078	2,177	0.93%
8	Sales (Billed)	43,068	48,090	(5,022)	-10.44%	215,977	221,981	(6,004)	-2.70%
8a	Unbilled Sales Prior Month (Period)								
8b	Unbilled Sales Current Month (Period)								
9	Company Use	40	35	5	14.57%	188	153	35	22.77%
10	T&D Losses Estimated @ 0.06	3,216	3,030	186	6.14%	14,115	13,985	130	0.93%
11	Unaccounted for Energy (estimated)	7,279	(661)	7,939	-1201.92%	4,975	(3,041)	8,016	-263.61%
12									
13	% Company Use to NEL	0.07%	0.07%	0.00%	0.00%	0.08%	0.07%	0.01%	14.29%
14	% T&D Losses to NEL	6.00%	6.00%	0.00%	0.00%	6.00%	6.00%	0.00%	0.00%
15	% Unaccounted for Energy to NEL	13.58%	-1.31%	14.89%	-1136.64%	2.11%	-1.30%	3.41%	-262.31%
	($)								
16	Fuel Cost of Sys Net Gen	-	-	-	0	-	-	-	0
16a	Fuel Related Transactions								
16b	Adjustments to Fuel Cost								
17	Fuel Cost of Power Sold								
18	Fuel Cost of Purchased Power	827,495	865,282	(37,787)	-4.37%	3,000,145	3,998,341	(998,196)	-24.97%
18a	Demand & Non Fuel Cost of Pur Power	1,316,848	1,160,739	156,109	13.45%	6,555,587	5,836,419	719,168	12.32%
18b	Energy Payments To Qualifying Facilities	1,015,294	1,440,951	(425,657)	-29.54%	5,268,804	6,833,767	(1,564,963)	-22.90%
19	Energy Cost of Economy Purch.								
20	Total Fuel & Net Power Transactions	3,159,637	3,466,972	(307,335)	-8.86%	14,824,536	16,668,527	(1,843,991)	-11.06%
	(Cents/KWH)								
21	Fuel Cost of Sys Net Gen								
21a	Fuel Related Transactions								
22	Fuel Cost of Power Sold								
23	Fuel Cost of Purchased Power	2.147	2.647	(0.500)	-18.89%	1.904	2.694	(0.790)	-29.32%
23a	Demand & Non Fuel Cost of Pur Power	3.416	3.550	(0.134)	-3.77%	4.160	3.932	0.228	5.80%
23b	Energy Payments To Qualifying Facilities	6.744	8.095	(1.351)	-16.69%	6.785	8.073	(1.288)	-15.95%
24	Energy Cost of Economy Purch.								
25	Total Fuel & Net Power Transactions	5.895	6.866	(0.971)	-14.14%	6.301	7.151	(0.850)	-11.89%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A8

PURCHASED POWER

(Exclusive of Economy Energy Purchases)
For the Period/Month of: MAY 2020 REVISED 7_27_2020

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) KWH FOR OTHER UTILITIES (000)	(5) KWH FOR INTERRUP-TIBLE (000)	(6) KWH FOR FIRM (000)	(7) CENTS/KWH (a) FUEL COST	(7) CENTS/KWH (b) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
ESTIMATED:								
FPL AND GULF/SOUTHERN	MS	32,694			32,694	2.646606	6.196915	865,282
TOTAL		32,694	0	0	32,694	2.646606	6.196915	865,282
ACTUAL:								
FPL	MS	14,634			14,634	2.773637	6.617330	405,894
GULF/SOUTHERN		23,913			23,913	1.763062	4.917673	421,601
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
TOTAL		38,547	0	0	38,547	4.536699	6.617330	827,495
CURRENT MONTH:								
DIFFERENCE		5,853	0	0	5,853	1.890093	0.42042	(37,787)
DIFFERENCE (%)		17.9%	0.0%	0.0%	17.9%	71.4%	6.8%	-4.4%
PERIOD TO DATE:								
ACTUAL	MS	157,602			157,602	1.903621	2.003621	3,000,145
ESTIMATED	MS	148,428			148,428	2.693784	2.793784	3,998,341
DIFFERENCE		9,174	0	0	9,174	(0.790163)	-0.790163	(998,196)
DIFFERENCE (%)		6.2%	0.0%	0.0%	6.2%	-29.3%	-28.3%	-25.0%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A8a

ENERGY PAYMENT TO QUALIFYING FACILITIES

For the Period/Month of: MAY 2020 REVISED 7_27_2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR OTHER UTILITIES (000)	KWH FOR INTERRUP-TIBLE (000)	KWH FOR FIRM (000)	CENTS/KWH (a) FUEL COST	CENTS/KWH (b) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
ESTIMATED:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		17,800			17,800	8.095230	8.095230	1,440,951
TOTAL		17,800	0	0	17,800	8.095230	8.095230	1,440,951
ACTUAL:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		15,055			15,055	6.743736	6.743736	1,015,294
TOTAL		15,055	0	0	15,055	6.743736	6.743736	1,015,294
CURRENT MONTH:								
DIFFERENCE		(2,745)	0	0	(2,745)	-1.351494	-1.351494	(425,657)
DIFFERENCE (%)		-15.4%	0.0%	0.0%	-15.4%	-16.7%	-16.7%	-29.5%
PERIOD TO DATE:								
ACTUAL	MS	77,653			77,653	6.785057	6.785057	5,268,804
ESTIMATED	MS	84,650			84,650	8.072968	8.072968	6,833,767
DIFFERENCE		(6,997)	0	0	(6,997)	-1.287911	-1.287911	(1,564,963)
DIFFERENCE (%)		-8.3%	0.0%	0.0%	-8.3%	-16.0%	-16.0%	-22.9%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A9

ECONOMY ENERGY PURCHASES

INCLUDING LONG TERM PURCHASES
For the Period/Month of: MAY 2020 REVISED 7_27_2020

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) TRANS. COST CENTS/KWH	(5) TOTAL $ FOR FUEL ADJ. (3) X (4) $	(6) COST IF GENERATED (a) CENTS/KWH	(6) COST IF GENERATED (b) TOTAL COST $	(7) FUEL SAVINGS (6)(b)-(5) $
ESTIMATED:							
TOTAL							
ACTUAL:							
TOTAL							

FOOTNOTE: PURCHASED POWER COSTS INCLUDE CUSTOMER, DEMAND & ENERGY CHARGES TOTALING 0

CURRENT MONTH:							
DIFFERENCE							
DIFFERENCE (%)							
PERIOD TO DATE:							
ACTUAL							
ESTIMATED							
DIFFERENCE							
DIFFERENCE (%)							

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: JUNE 2020 REVISED 7_27_2020

		DOLLARS				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)			0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	1,047,952	1,245,385	(197,433)	-15.9%	48,775	44,618	4,157	9.3%	2.14854	2.79123	(0.64269)	-23.0%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	1,521,145	1,399,731	121,414	8.7%	48,775	44,618	4,157	9.3%	3.11870	3.13716	(0.01846)	-0.6%
11	Energy Payments to Qualifying Facilities (A8a)	937,954	1,263,018	(325,064)	-25.7%	13,491	15,700	(2,209)	-14.1%	6.95260	8.04470	(1.09210)	-13.6%
12	TOTAL COST OF PURCHASED POWER	3,507,051	3,908,134	(401,083)	-10.3%	62,266	60,318	1,948	3.2%	5.63240	6.47924	(0.84684)	-13.1%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					62,266	60,318	1,948	3.2%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	10,620	153,991	(143,371)	-43.2%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	3,496,431	3,754,143	(257,712)	-6.9%	62,266	60,318	1,948	3.2%	5.61534	6.22394	(0.60860)	-9.8%
21	Net Unbilled Sales (A4)	396,178 *	(49,434) *	445,612	-901.4%	7,055	(794)	7,850	-988.3%	0.77029	(0.08605)	0.85634	-995.2%
22	Company Use (A4)	2,382 *	2,987 *	(605)	-20.3%	42	48	(6)	-11.6%	0.00463	0.00520	(0.00057)	-11.0%
23	T & D Losses (A4)	209,789 *	225,244 *	(15,455)	-6.9%	3,736	3,619	117	3.2%	0.40790	0.39210	0.01580	4.0%
24	SYSTEM KWH SALES	3,496,431	3,754,143	(257,712)	-6.9%	51,432	57,445	(6,013)	-10.5%	6.79816	6.53519	0.26297	4.0%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	3,496,431	3,754,143	(257,712)	-6.9%	51,432	57,445	(6,013)	-10.5%	6.79816	6.53519	0.26297	4.0%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	3,496,431	3,754,143	(257,712)	-6.9%	51,432	57,445	(6,013)	-10.5%	6.79816	6.53519	0.26297	4.0%
28	GPIF**												
29	TRUE-UP**	161,204	161,204	0	0.0%	51,432	57,445	(6,013)	-10.5%	0.31343	0.28062	0.03281	11.7%
30	TOTAL JURISDICTIONAL FUEL COST (Excluding GSLD Apportionment)	3,657,635	3,915,347	(257,712)	-6.6%	51,432	57,445	(6,013)	-10.5%	7.11159	6.81582	0.29577	4.3%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									7.22602	6.92549	0.30053	4.3%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.226	6.925	0.301	4.4%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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Company: FLORIDA PUBLIC UTILITIES COMPANY

CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: JUNE 2020 REVISED 7_27_2020

		PERIOD TO DATE	DOLLARS			PERIOD TO DATE	MWH			CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)	0	0	0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	4,048,097	5,243,726	(1,195,629)	-22.8%	206,377	193,046	13,331	6.9%	1.96151	2 71631	(0.75480)	-27.8%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	8,076,732	7,236,150	840,582	11.6%	206,377	193,046	13,331	6.9%	3.91358	3.74840	0.16518	4.4%
11	Energy Payments to Qualifying Facilities (A8a)	6,206,758	8,096,785	(1,890,027)	-23.3%	91,144	100,350	(9,206)	-9.2%	6.80986	8.06855	(1.25869)	-15.6%
12	TOTAL COST OF PURCHASED POWER	18,331,587	20,576,661	(2,245,074)	-10.9%	297,521	293,396	4,125	1.4%	6.16145	7.01327	(0.85182)	-12.2%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					297,521	293,396	4,125	1.4%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	(16,709)	730,341	(747,050)	-102.3%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	18,348,296	19,846,320	(1,498,024)	-7.6%	297,521	293,396	4,125	1.4%	6.16706	6.76434	(0.59728)	-8.8%
21	Net Unbilled Sales (A4)	741,912 *	(259,417) *	1,001,329	-386.0%	12,030	(3,835)	15,865	-413.7%	0.27744	(0.09284)	0.37028	-398.8%
22	Company Use (A4)	14,216 *	13,610 *	606	4.5%	231	201	29	14.6%	0.00532	0.00487	0.00045	9.2%
23	T & D Losses (A4)	1,100,882 *	1,190,794 *	(89,912)	-7.6%	17,851	17,604	247	1.4%	0.41168	0.42616	(0.01448)	-3.4%
24	SYSTEM KWH SALES	18,348,296	19,846,320	(1,498,024)	-7.6%	267,409	279,426	(12,017)	-4.3%	6.86150	7.10253	(0.24103)	-3.4%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	18,348,296	19,846,320	(1,498,024)	-7.6%	267,409	279,426	(12,017)	-4.3%	6.86150	7.10253	(0.24103)	-3.4%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	18,348,296	19,846,320	(1,498,024)	-7.6%	267,409	279,426	(12,017)	-4.3%	6.86150	7.10253	(0.24103)	-3.4%
28	GPIF**												
29	TRUE-UP**	967,224	967,224	(0)	0.0%	267,409	279,426	(12,017)	-4.3%	0.36170	0.34615	0.01555	4.5%
30	TOTAL JURISDICTIONAL FUEL COST	19,315,520	20,813,544	(1,498,024)	-7.2%	267,409	279,426	(12,017)	-4.3%	7.22321	7.44868	(0.22547)	-3.0%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									7.33943	7.56853	(0.22910)	-3.0%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.339	7.569	(0.230)	-3.0%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: JUNE 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. Fuel Cost & Net Power Transactions								
1. Fuel Cost of System Net Generation	$ 0	$ 0	$ 0	0.0%	$ 0	$ 0	$ 0	0.0%
1a. Fuel Related Transactions (Nuclear Fuel Disposal)								
2. Fuel Cost of Power Sold								
3. Fuel Cost of Purchased Power	1,047,952	1,245,385	(197,433)	-15.9%	4,048,097	5,243,726	(1,195,629)	-22.8%
3a. Demand & Non Fuel Cost of Purchased Power	1,521,145	1,399,731	121,414	8.7%	8,076,732	7,236,150	840,582	11.6%
3b. Energy Payments to Qualifying Facilities	937,954	1,263,018	(325,064)	-25.7%	6,206,758	8,096,785	(1,890,027)	-23.3%
4. Energy Cost of Economy Purchases								
5. Total Fuel & Net Power Transactions	3,507,051	3,908,134	(401,083)	-10.3%	18,331,587	20,576,661	(2,245,074)	-10.9%
6. Adjustments to Fuel Cost (Describe Items)								
6a. Special Meetings - Fuel Market Issue	12,649	19,300	(6,651)	-34.5%	62,227	110,000	(47,773)	-43.4%
7. Adjusted Total Fuel & Net Power Transactions	3,519,699	3,927,434	(407,734)	-10.4%	18,393,814	20,686,661	(2,292,848)	-11.1%
8. Less Apportionment To GSLD Customers	10,620	153,991	(143,371)	-93.1%	(16,709)	730,341	(747,050)	-102.3%
9. Net Total Fuel & Power Transactions To Other Classes	$ 3,509,079	$ 3,773,443	$ (264,363)	-7.0%	$ 18,410,523	$ 19,956,320	$ (1,545,798)	-7.8%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: JUNE 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
B. Sales Revenues (Exclude Revenue Taxes & Franchise Taxes)								
1. Jurisidictional Sales Revenue (Excluding GSLD)	$	$	$		$	$	$	
a. Base Fuel Revenue								
b. Fuel Recovery Revenue	4,197,479	4,295,011	(97,532)	-2.3%	19,815,364	20,873,087	(1,057,723)	-5.1%
c. Jurisidictional Fuel Revenue	4,197,479	4,295,011	(97,532)	-2.3%	19,815,364	20,873,087	(1,057,723)	-5.1%
d. Non Fuel Revenue	2,320,563	2,460,714	(140,151)	-5.7%	12,559,050	12,613,498	(54,449)	-0.4%
e. Total Jurisdictional Sales Revenue	6,518,042	6,755,725	(237,683)	-3.5%	32,374,414	33,486,585	(1,112,171)	-3.3%
2. Non Jurisdictional Sales Revenue	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales Revenue (Excluding GSLD)	$ 6,518,042	$ 6,755,725	$ (237,683)	-3.5%	$ 32,374,414	$ 33,486,585	$ (1,112,171)	-3.3%
C. KWH Sales (Excluding GSLD)								
1. Jurisdictional Sales KWH	51,057,735	55,225,466	(4,167,731)	-7.6%	265,901,560	270,794,887	(4,893,327)	-1.8%
2. Non Jurisdictional Sales	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales	51,057,735	55,225,466	(4,167,731)	-7.6%	265,901,560	270,794,887	(4,893,327)	-1.8%
4. Jurisdictional Sales % of Total KWH Sales	100.00%	100.00%	0.00%	0.0%	100.00%	100.00%	0.00%	0.0%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: JUNE 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. True-up Calculation (Excluding GSLD)								
1. Jurisdictional Fuel Rev. (line B-1c)	$ 4,197,479	$ 4,295,011	$ (97,532)	-2.3%	$ 19,815,364	$ 20,873,087	$ (1,057,723)	-5.1%
2. Fuel Adjustment Not Applicable								
a. True-up Provision	161,204	161,204	0	0.0%	967,224	967,224	(0)	0.0%
b. Incentive Provision								
c. Transition Adjustment (Regulatory Tax Refund)							0	0.0%
3. Jurisdictional Fuel Revenue Applicable to Period	4,036,275	4,133,807	(97,532)	-2.4%	18,848,140	19,905,862	(1,057,722)	-5.3%
4. Adjusted Total Fuel & Net Power Transaction (Line A-7)	3,509,079	3,773,443	(264,363)	-7.0%	18,410,523	19,956,320	(1,545,798)	-7.8%
5. Jurisdictional Sales % of Total KWH Sales (Line C-4)	100%	100%	0.00%	0.0%	N/A	N/A		
6. Jurisdictional Total Fuel & Net Power Transactions (Line D-4 x Line D-5 x *)	3,509,079	3,773,443	(264,364)	-7.0%	18,410,523	19,956,320	(1,545,798)	-7.8%
7. True-up Provision for the Month Over/Under Collection (Line D-3 - Line D-6)	527,196	360,364	166,832	46.3%	437,617	(50,458)	488,075	-967.3%
8. Interest Provision for the Month	(256)	(3,593)	3,337	-92.9%	(19,919)	(22,921)	3,002	-13.1%
9. True-up & Inst. Provision Beg. of Month	(3,255,569)	1,042,497	(4,298,066)	-412.3%	(3,952,348)	666,626	(4,618,974)	-692.9%
9a. Deferred True-up Beginning of Period								
10. True-up Collected (Refunded)	161,204	161,204	0	0.0%	967,224	967,224	(0)	0.0%
11. End of Period - Total Net True-up (Lines D7 through D10)	$ (2,567,425)	$ 1,560,472	$ (4,127,897)	-264.5%	$ (2,567,425)	$ 1,560,472	$ (4,127,897)	-264.5%

* Jurisdictional Loss Multiplier

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: JUNE 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
E. Interest Provision (Excluding GSLD)							--	--
1. Beginning True-up Amount (lines D-9 + 9a)	$ (3,255,569)	$ 1,042,497	$ (4,298,066)	-412.3%	N/A	N/A	--	--
2. Ending True-up Amount Before Interest	(2,567,169)	1,564,065	(4,131,234)	-264.1%	N/A	N/A	--	--
(line D-7 + Lines D-9 + 9a + D-10)					N/A	N/A	--	--
3. Total of Beginning & Ending True-up Amount	(5,822,738)	2,606,562	(8,429,300)	-323.4%	N/A	N/A	--	--
4. Average True-up Amount (50% of Line E-3)	$ (2,911,369)	$ 1,303,281	$ (4,214,650)	-323.4%	N/A	N/A	--	--
5. Interest Rate - First Day Reporting Business Month	0.1100%	N/A	--	--	N/A	N/A	--	--
6. Interest Rate - First Day Subsequent Business Month	0.1000%	N/A	--	--	N/A	N/A	--	--
7. Total (Line E-5 + Line E-6)	0.2100%	N/A	--	--	N/A	N/A	--	--
8. Average Interest Rate (50% of Line E-7)	0.1050%	N/A	--	--	N/A	N/A	--	--
9. Monthly Average Interest Rate (Line E-8 / 12)	0.0088%	N/A	--	--	N/A	N/A	--	--
10. Interest Provision (Line E-4 x Line E-9)	(256)	N/A	--	--	N/A	N/A	--	--

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Company: **FLORIDA PUBLIC UTILITIES COMPANY**
CONSOLIDATED ELECTRIC DIVISIONS

Schedule A4

ELECTRIC ENERGY ACCOUNT
Month of: JUNE 2020 REVISED 7_27_2020

			CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH DIFFERENCE %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE DIFFERENCE %
	(MWH)									
1	System Net Generation		0	0	0	0.00%	0	0	0	0.00%
2	Power Sold									
3	Inadvertent Interchange Delivered - NET									
4	Purchased Power		48,775	44,618	4,157	9.32%	206,377	193,046	13,331	6.91%
4a	Energy Purchased For Qualifying Facilities		13,491	15,700	(2,209)	-14.07%	91,144	100,350	(9,206)	-9.17%
5	Economy Purchases									
6	Inadvertent Interchange Received - NET									
7	Net Energy for Load		62,266	60,318	1,948	3.23%	297,521	293,396	4,125	1.41%
8	Sales (Billed)		51,432	57,445	(6,013)	-10.47%	267,409	279,426	(12,017)	-4.30%
8a	Unbilled Sales Prior Month (Period)									
8b	Unbilled Sales Current Month (Period)									
9	Company Use		42	48	(6)	-11.62%	231	201	29	14.57%
10	T&D Losses Estimated @	0.06	3,736	3,619	117	3.23%	17,851	17,604	247	1.40%
11	Unaccounted for Energy (estimated)		7,055	(794)	7,850	-988.29%	12,030	(3,835)	15,865	-413.69%
12										
13	% Company Use to NEL		0.07%	0.08%	-0.01%	-12.50%	0.08%	0.07%	0.01%	14.29%
14	% T&D Losses to NEL		6.00%	6.00%	0.00%	0.00%	6.00%	6.00%	0.00%	0.00%
15	% Unaccounted for Energy to NEL		11.33%	-1.32%	12.65%	-958.33%	4.04%	-1.31%	5.35%	-408.40%
	($)									
16	Fuel Cost of Sys Net Gen		-	-	-	0	-	-	-	0
16a	Fuel Related Transactions									
16b	Adjustments to Fuel Cost									
17	Fuel Cost of Power Sold									
18	Fuel Cost of Purchased Power		1,047,952	1,245,385	(197,433)	-15.85%	4,048,097	5,243,726	(1,195,629)	-22.80%
18a	Demand & Non Fuel Cost of Pur Power		1,521,145	1,399,731	121,414	8.67%	8,076,732	7,236,150	840,582	11.62%
18b	Energy Payments To Qualifying Facilities		937,954	1,263,018	(325,064)	-25.74%	6,206,758	8,096,785	(1,890,027)	-23.34%
19	Energy Cost of Economy Purch.									
20	Total Fuel & Net Power Transactions		3,507,051	3,908,134	(401,083)	-10.26%	18,331,587	20,576,661	(2,245,074)	-10.91%
	(Cents/KWH)									
21	Fuel Cost of Sys Net Gen									
21a	Fuel Related Transactions									
22	Fuel Cost of Power Sold									
23	Fuel Cost of Purchased Power		2.149	2.791	(0.642)	-23.00%	1.962	2.716	(0.754)	-27.76%
23a	Demand & Non Fuel Cost of Pur Power		3.119	3.137	(0.018)	-0.57%	3.914	3.748	0.166	4.43%
23b	Energy Payments To Qualifying Facilities		6.953	8.045	(1.092)	-13.57%	6.810	8.069	(1.259)	-15.60%
24	Energy Cost of Economy Purch.									
25	Total Fuel & Net Power Transactions		5.632	6.479	(0.847)	-13.07%	6.161	7.013	(0.852)	-12.15%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A8

PURCHASED POWER

(Exclusive of Economy Energy Purchases)
For the Period/Month of: JUNE 2020 REVISED 7_27_2020

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) KWH FOR OTHER UTILITIES (000)	(5) KWH FOR INTERRUP-TIBLE (000)	(6) KWH FOR FIRM (000)	(7) CENTS/KWH (a) FUEL COST	(7) CENTS/KWH (b) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
ESTIMATED:								
FPL AND GULF/SOUTHERN	MS	44,618			44,618	2.791233	5.928395	1,245,385
TOTAL		44,618	0	0	44,618	2.791233	5.928395	1,245,385
ACTUAL:								
FPL	MS	20,624			20,624	2.623725	6.863887	541,117
GULF/SOUTHERN		28,151			28,151	1.800415	4.097505	506,835
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
Other		0			0	0.000000	0.000000	0
TOTAL		48,775	0	0	48,775	4.424140	6.863887	1,047,952
CURRENT MONTH:								
DIFFERENCE		4,157	0	0	4,157	1.632907	0.93549	(197,433)
DIFFERENCE (%)		9.3%	0.0%	0.0%	9.3%	58.5%	15.8%	-15.9%
PERIOD TO DATE:								
ACTUAL	MS	206,377			206,377	1.961506	2.061506	4,048,097
ESTIMATED	MS	193,046			193,046	2.716307	2.816307	5,243,726
DIFFERENCE		13,331	0	0	13,331	(0.754801)	-0.754801	(1,195,629)
DIFFERENCE (%)		6.9%	0.0%	0.0%	6.9%	-27.8%	-26.8%	-22.8%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A8a

ENERGY PAYMENT TO QUALIFYING FACILITIES

For the Period/Month of: JUNE 2020 REVISED 7_27_2020

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) KWH FOR OTHER UTILITIES (000)	(5) KWH FOR INTERRUP-TIBLE (000)	(6) KWH FOR FIRM (000)	(7) CENTS/KWH (a) FUEL COST	(7) CENTS/KWH (b) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ. (6)X(7)(a) $
ESTIMATED:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		15,700			15,700	8.044701	8.044701	1,263,018
TOTAL		15,700	0	0	15,700	8.044701	8.044701	1,263,018
ACTUAL:								
WEST-ROCK, EIGHT FLAGS AND RAYONIER		13,491			13,491	6.952599	6.952599	937,954
TOTAL		13,491	0	0	13,491	6.952599	6.952599	937,954
CURRENT MONTH:								
DIFFERENCE		(2,209)	0	0	(2,209)	-1.092102	-1.092102	(325,064)
DIFFERENCE (%)		-14.1%	0.0%	0.0%	-14.1%	-13.6%	-13.6%	-25.7%
PERIOD TO DATE:								
ACTUAL	MS	91,144			91,144	6.809856	6.809856	6,206,758
ESTIMATED	MS	100,350			100,350	8.068545	8.068545	8,096,785
DIFFERENCE		(9,206)	0	0	(9,206)	-1.258689	-1.258689	(1,890,027)
DIFFERENCE (%)		-9.2%	0.0%	0.0%	-9.2%	-15.6%	-15.6%	-23.3%

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Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

SCHEDULE A9

ECONOMY ENERGY PURCHASES

INCLUDING LONG TERM PURCHASES
For the Period/Month of: JUNE 2020 REVISED 7_27_2020

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) TRANS. COST CENTS/KWH	(5) TOTAL $ FOR FUEL ADJ. (3) X (4) $	(6) COST IF GENERATED (a) CENTS/KWH	(6) COST IF GENERATED (b) TOTAL COST $	(7) FUEL SAVINGS (6)(b)-(5) $
ESTIMATED:							
TOTAL							
ACTUAL:							
TOTAL							

FOOTNOTE: PURCHASED POWER COSTS INCLUDE CUSTOMER, DEMAND & ENERGY CHARGES TOTALING 0

CURRENT MONTH:							
DIFFERENCE							
DIFFERENCE (%)							
PERIOD TO DATE:							
ACTUAL							
ESTIMATED							
DIFFERENCE							
DIFFERENCE (%)							

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021
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FLORIDA DIVISION-CONSOLIDATED		(a) DOLLARS		(b) MWH		(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)					
2	Nuclear Fuel Disposal Costs (E2)					
3	Coal Car Investment					
4	Adjustments to Fuel Cost					
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0		0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	13,359,070		468,492		2.85150
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)					
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)					
9	Energy Cost of Sched E Economy Purch (E9)					
10	Demand & Non Fuel Cost of Purch Power (E2)	16,362,377		468,492		3.49256
10a	Demand Costs of Purchased Power	15,135,244	*			
10b	Non-fuel Energy & Customer Costs of Purchased Power	1,227,132	*			
11	Energy Payments to Qualifying Facilities (E8a)	14,686,523		196,205		7.48529
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	44,407,969		664,697		6.68093
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	44,407,969		664,697		6.68093
14	Fuel Cost of Economy Sales (E6)					
15	Gain on Economy Sales (E6)					
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)					
17	Fuel Cost of Other Power Sales					
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0		0		0.00000
19	Net Inadvertent Interchange					
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	44,407,969		664,697		6.68093
21	Net Unbilled Sales	0	*	0		0.00000
22	Company Use	44,361	*	664		0.00701
23	T & D Losses	2,070,307	*	30,988		0.32704
24	SYSTEM MWH SALES	44,407,969		633,045		7.01498
25	Wholesale MWH Sales					
26	Jurisdictional MWH Sales	44,407,969		633,045		7.01498
26a	Jurisdictional Loss Multiplier	1.00000		1.00000		
27	Jurisdictional MWH Sales Adjusted for Line Losses	44,407,969		633,045		7.01498
27a	GSLD1 MWH Sales			22,466		
27b	Other Classes MWH Sales			610,578		
27c	GSLD1 CP KW			90,000	*	
28	Projected Unbilled Revenues	0		610,578		0.00000
29	GPIF **					
30	TRUE-UP (OVER) UNDER RECOVERY **	(297,168)		610,578		-0.04867
31	TOTAL JURISDICTIONAL FUEL COST	44,110,801		610,578		7.22443
31a	Demand Purchased Power Costs (Line 10a)	15,135,244	*			
31b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	29,272,725	*			
31c	True up Over/Under Recovery (Line 29)	(297,168)	*			
31d	Unbilled Revenues	0				

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

REVISED 10_22_2020

FLORIDA DIVISION-CONSOLIDATED		(a) DOLLARS	(b) MWH		(c) CENTS/KWH	
	APPORTIONMENT OF DEMAND COSTS					
31	Total Demand Costs (Line 31a)	15,135,244				
32	GSLD1 Portion of Demand Costs (Line 31a) Including Line Losses(Line 27c x $5.85)	374,724	370,900	(KW)	$1.01	/KW
33	Balance to Other Classes	14,760,520	610,578		2.41747	
	APPORTIONMENT OF NON-DEMAND COSTS					
34	Total Non-demand Costs(Line 31b)	29,272,725				
35	Total KWH Purchased (Line 12)		664,697	KWH		
36	Average Cost per KWH Purchased				4.40392	
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)				4.53604	
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,275,244	22,466		5.67627	
39	Balance to Other Classes	27,997,481	610,578		4.58540	
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS					
40a	Total GSLD1 Demand Costs (Line 32)	374,724	370,900	(KW)	$1.01	/KW
40b	Revenue Tax Factor				1.00072	
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded				$1.01	/KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,275,244	22,466		5.67627	
40e	Total Non-demand Costs Including True-up	1,275,244	22,466		5.67627	
40f	Revenue Tax Factor				1.00072	
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded				5.68036	
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS					
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	42,758,001	610,578		7.00287	
41b	Less: Total Demand Cost Recovery	14,760,520 ***				
41c	Total Other Costs to be Recovered	27,997,481	610,578		4.58540	
41d	Unbilled Revenue	0	610,578		0.00000	
41e	Other Classes' Portion of True-up (Line 30c)	(297,168)	610,578		-0.04867	
41f	Total Demand & Non-demand Costs Including True-up	27,700,313	610,578		4.53673	
42	Revenue Tax Factor				1.00072	
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	27,720,257			4.540	

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

REVISED 10_22_2020

FLORIDA DIVISION-CONSOLIDATED

	Rate Schedule	(1) KWH Sales	(2) 12 CP Load Factor	(3) (1)/((2)*8,760) CP KW At Meter	(4) Demand Loss Factor	(5) Energy Loss Factor	(6) (3)*(4) CP KW At GEN.	(7) (1)*(5) KWH At GEN.	(8) (6)/Total Col. (6) 12 CP Demand Percentage	(9) (7)/Total Col. (7) Energy Percentage
44	RS	293,132,452	57.542%	58,153.0	1.089	1.030	63,328.6	301,926,426	54.67%	48.01%
45	GS	53,674,502	63.463%	9,654.8	1.089	1.030	10,514.1	55,284,737	9.08%	8.79%
46	GSD	172,118,500	73.488%	26,736.6	1.089	1.030	29,116.2	177,282,055	25.14%	28.19%
47	GSLD	84,164,138	82.761%	11,609.1	1.089	1.030	12,642.3	86,689,062	10.92%	13.78%
48	LS	7,488,860	416.653%	205.2	1.089	1.030	223.5	7,713,526	0.19%	1.23%
49		0	416.653%	0.0	1.089	1.030	0.0	0	0.00%	0.00%
	TOTAL	610,578,452		106,358.7			115,824.7	628,895,806	100.00%	100.00%

	Rate Schedule	(10) 12/13 * (8) 12/13 Of 12 CP	(11) 1/13 * (9) 1/13 Of Energy	(12) (10) + (11) Demand Allocation Percentage	(13) Tot. Col. 13 * (9) Demand Dollars	(14) (13)/(1) Demand Cost Recovery	(15) (14) * 1.00072 Demand Cost Recovery Adj for Taxes	(16) Other Charges	(17) (15) + (16) Levelized Adjustment
50	RS	50.46%	3.69%	54.15%	$7,992,822	0.02727	0.02729	0.04540	$ 0.07269
51	GS	8.38%	0.68%	9.06%	1,337,303	0.02492	0.02494	0.04540	$ 0.07034
52	GSD	23.21%	2.17%	25.38%	3,746,220	0.02177	0.02179	0.04540	$ 0.06719
53	GSLD	10.08%	1.06%	11.14%	1,644,322	0.01954	0.01955	0.04540	$ 0.06495
54	LS	0.18%	0.09%	0.27%	39,853	0.00532	0.00532	0.04540	$ 0.05072
	TOTAL	92.31%	7.69%	100.00%	$14,760,520				

Step Rate Allocation for Residential Customers

	Rate Schedule	(18) Allocation	(19) Annual kWh	(20) Levelized Adj.	(21) (19) * (20) Revenues
56	RS	Sales	293,132,452	$0.07269	$21,307,798
57	RS	<= 1,000kWh/mo.	220,796,544	$0.06961	$15,368,630
58	RS	> 1,000 kWh/mo.	72,335,909	$0.08211	$5,939,168
59	RS	Total Sales	293,132,452		$21,307,798

(2) From Gulf Power 2015 Load Research results.

TOU Rates

	Rate Schedule	(22) On Peak Rate Differential	(23) Off Peak Rate Differential	(24) Levelized Adj. On Peak	(25) Levelized Adj. Off Peak
60	RS	0.0840	(0.0390)	$0.15361	$0.03061
61	GS	0.0400	(0.0500)	$0.11034	$0.02034
62	GSD	0.0400	(0.0325)	$0.10719	$0.03469
63	GSLD	0.0600	(0.0300)	$0.12495	$0.03495
64	Interruptible	(0.0150)	-	$0.04995	$0.06495

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FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2020 - DECEMBER 2020
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

REVISED 10_22_2020

FLORIDA DIVISION-CONSOLIDATED

Over-recovery of purchased power costs for the period January 2020 - December 2020. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2020.)(Estimated)	$	(297,168)
Portion of 2020 Over-recovery to be refunded for the period January 2021 - December 2021	$	(297,168)
Estimated kilowatt hour sales for the months of January 2021 - December 2021 as per estimate filed with the Commission. (Excludes GSLD1 customers)		610,578,452
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2021- December 2021		-0.04867

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FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

REVISED 10_22_2020

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) ESTIMATED JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		1,061,384	1,200,971	660,727	774,054	802,711	1,312,959	1,375,650	1,428,105	1,497,300	1,280,638	866,017	1,098,553	13,359,070	3
3a	DEMAND & NON FUEL COST OF PUR POWER		1,414,432	1,201,333	1,152,753	1,136,450	1,324,222	1,537,211	1,515,874	1,504,767	1,526,253	1,456,966	1,160,028	1,211,088	16,141,377	3a
3b	QUALIFYING FACILITIES		1,105,543	793,259	1,361,837	1,316,239	1,300,920	1,256,084	1,286,004	1,203,963	1,169,010	1,297,970	1,297,900	1,297,794	14,686,523	3b
4	OTHER FUEL RELATED COSTS		17,850	17,850	19,300	17,850	17,850	19,300	17,850	17,850	19,300	17,850	17,850	20,300	221,000	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		3,599,209	3,213,413	3,194,617	3,244,594	3,445,703	4,125,553	4,195,378	4,154,684	4,211,863	4,053,424	3,341,795	3,627,735	44,407,969	5
5a	LESS: TOTAL DEMAND COST RECOVERY		1,296,893	1,092,259	1,064,815	1,043,754	1,218,156	1,409,479	1,382,820	1,369,738	1,390,632	1,333,433	1,063,871	1,094,669	14,760,520	5a
5b	TOTAL OTHER COST TO BE RECOVERED		2,302,316	2,121,155	2,129,803	2,200,840	2,227,547	2,716,074	2,812,558	2,784,946	2,821,230	2,719,992	2,277,924	2,533,065	29,647,449	5b
6	APPORTIONMENT TO GSLD1 CLASS		135,396	190,407	151,419	105,618	65,280	104,867	124,704	161,270	151,488	205,610	109,091	144,818	1,649,968	6
6a	BALANCE TO OTHER CLASSES		2,166,920	1,930,748	1,978,384	2,095,222	2,162,266	2,611,207	2,687,854	2,623,676	2,669,742	2,514,381	2,168,833	2,388,248	27,997,481	6a
6b	SYSTEM KWH SOLD (MWH)		51,382	48,709	41,098	43,926	46,626	59,044	61,606	62,150	63,143	57,849	44,600	52,912	633,045	6b
7	GSLD1 MWH SOLD		1,918	3,188	1,838	1,180	568	1,328	1,700	2,428	2,263	3,028	1,234	1,798	22,466	7
7a	BALANCE MWH SOLD OTHER CLASSES		49,464	45,521	39,261	42,746	46,058	57,717	59,906	59,722	60,881	54,822	43,367	51,114	610,578	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		4.38079	4.2414	5.03908	4.90155	4.69462	4.52418	4.48682	4.39314	4.38521	4.58646	5.00117	4.67235	4.5854	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		4.38079	4.24140	5.03908	4.90155	4.69462	4.52418	4.48682	4.39314	4.38521	4.58646	5.00117	4.67235	4.58540	9
10	PROJECTED UNBILLED REVENUES(CENTS/KWH)		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	10
11	GPIF (CENTS/KWH)															11
12	TRUE-UP (CENTS/KWH)	(297,168)	(0.04867)	(0.04867)	(0.04867)	(0.04867)	(0.04867)	(0.04867)	(0.04867)	(0.04867)	(0.04867)	(0.04867)	(0.04867)	(0.04867)	(0.04867)	12
13	TOTAL		4.33212	4.19273	4.99041	4.85288	4.64595	4.47551	4.43815	4.34447	4.33654	4.53779	4.95250	4.62368	4.53673	13
14	REVENUE TAX FACTOR	0.00072	0.00312	0.00302	0.00359	0.00349	0.00335	0.00322	0.00320	0.00313	0.00312	0.00327	0.00357	0.00333	0.00327	14
15	RECOVERY FACTOR ADJUSTED FOR TAXES		4.33524	4.19575	4.99400	4.85637	4.64930	4.47873	4.44135	4.34760	4.33966	4.54106	4.95607	4.62701	4.54000	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		4.335	4.196	4.994	4.856	4.649	4.479	4.441	4.348	4.34	4.541	4.956	4.627	4.540	16

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DOCKET NO. 20200001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(Second Revised CDY-4)
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FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

REVISED 10_22_2020

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL KWH PURCHASED	(5) KWH FOR OTHER UTILITIES	(6) KWH FOR INTERRUPTIBLE	(7) KWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2021	FPL / GULF POWER	MS	38,479,672			38,479,672	2.758298	6.434088	1,061,384
FEBRUARY 2021	FPL / GULF POWER	MS	39,619,393			39,619,393	3.031271	6.063456	1,200,971
MARCH 2021	FPL / GULF POWER	MS	24,253,236			24,253,236	2.724284	7.477272	660,727
APRIL 2021	FPL / GULF POWER	MS	27,542,425			27,542,425	2.810407	6.936588	774,054
MAY 2021	FPL / GULF POWER	MS	30,847,138			30,847,138	2.602222	6.895074	802,711
JUNE 2021	FPL / GULF POWER	MS	45,706,371			45,706,371	2.872595	6.235825	1,312,959
JULY 2021	FPL / GULF POWER	MS	48,072,840			48,072,840	2.861596	6.014882	1,375,650
AUGUST 2021	FPL / GULF POWER	MS	49,549,074			49,549,074	2.882202	5.919124	1,428,105
SEPTEMBER 2021	FPL / GULF POWER	MS	51,087,205			51,087,205	2.930871	5.918415	1,497,300
OCTOBER 2021	FPL / GULF POWER	MS	44,190,759			44,190,759	2.897978	6.194970	1,280,638
NOVEMBER 2021	FPL / GULF POWER	MS	30,130,266			30,130,266	2.874243	6.724286	866,017
DECEMBER 2021	FPL / GULF POWER	MS	39,013,549			39,013,549	2.815824	5.920099	1,098,553
TOTAL			468,491,927	0	0	468,491,927	2.851505	6.296895	13,359,070

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FLORIDA PUBLIC UTILITIES COMPANY

FLORIDA DIVISION-CONSOLIDATED

PURCHASED POWER

ENERGY PAYMENT TO QUALIFYING FACILITIES

REVISED 10_22_2020

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		15,471,000			15,471,000	7.145905	7.145905	1,105,543
FEBRUARY	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		11,525,000			11,525,000	6.882941	6.882941	793,259
MARCH	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		18,900,000			18,900,000	7.205487	7.205487	1,361,837
APRIL	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		18,580,000			18,580,000	7.084171	7.084171	1,316,239
MAY	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		18,110,000			18,110,000	7.183435	7.183435	1,300,920
JUNE	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		16,290,000			16,290,000	7.710767	7.710767	1,256,084
JULY	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		16,613,000			16,613,000	7.740950	7.740950	1,286,004
AUGUST	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		15,708,000			15,708,000	7.664649	7.664649	1,203,963
SEPTEMBER	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		15,213,000			15,213,000	7.684283	7.684283	1,169,010
OCTOBER	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		16,551,000			16,551,000	7.842245	7.842245	1,297,970
NOVEMBER	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		16,700,000			16,700,000	7.771856	7.771856	1,297,900
DECEMBER	2021	WEST-ROCK / RAYONIER / EIGHT FLAGS		16,544,000			16,544,000	7.844500	7.844500	1,297,794
TOTAL				196,205,000	0	0	196,205,000	7.485295	7.485295	14,686,523

EXHIBIT NO. _________

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FLORIDA PUBLIC UTILITIES COMPANY

(Second Revised CDY-4)

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SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
RESIDENTIAL BILL COMPARISON

REVISED 10_22_2020

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

	JANUARY 2021	FEBRUARY 2021	MARCH 2021	APRIL 2021	MAY 2021	JUNE 2021	JULY 2021
BASE RATE REVENUES ** $	57.02	57.02	57.02	55.48	55.48	55.48	55.48
FUEL RECOVERY FACTOR CENTS/KWH	6.96	6.96	6.96	6.96	6.96	6.96	6.96
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	69.61	69.61	69.61	69.61	69.61	69.61	69.61
GROSS RECEIPTS TAX	3.25	3.25	3.25	3.21	3.21	3.21	3.21
TOTAL REVENUES *** $	129.88	129.88	129.88	128.30	128.30	128.30	128.30

	AUGUST 2021	SEPTEMBER 2021	OCTOBER 2021	NOVEMBER 2021	DECEMBER 2021	PERIOD TOTAL
BASE RATE REVENUES ** $	55.48	55.48	55.48	55.48	55.48	670.38
FUEL RECOVERY FACTOR CENTS/KWH	6.96	6.96	6.96	6.96	6.96	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	69.61	69.61	69.61	69.61	69.61	835.32
GROSS RECEIPTS TAX	3.21	3.21	3.21	3.21	3.21	38.64
TOTAL REVENUES *** $	128.30	128.30	128.30	128.30	128.30	1,544.34

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:		April 2021
CUSTOMER CHARGE	17.16	17.16
CENTS/KWH	24.02	24.02
CONSERVATION FACTOR	1.50	1.50
STORM SURCHARGE (Matthew/Irma)	1.54	
STORM SURCHARGE (Michael/Dorian)	12.80	12.80
	57.02	55.48

EXHIBIT NO. __________
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*** EXCLUDES FRANCHISE TAXES

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 31
PARTY: GULF POWER COMPANY – DIRECT
DESCRIPTION: Richard L. Hume RLH-1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 32
PARTY: GULF POWER COMPANY – DIRECT
DESCRIPTION: Richard L. Hume RLH-2

Gulf Power

January 21, 2020

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

Re: Docket No. 20200001-EI

Dear Mr. Teitzman:

Attached for official filing in the subject docket on behalf of Gulf Power Company are the following for the month of December 2019 based on actual amounts.

1.	Schedule A1:	Comparison of Estimated and Actual Fuel and Purchased Power Cost Recovery Factor
2.	Schedule A2:	Calculation of True-up and Interest Provision
3.	Schedule A3:	Generating System Comparative Data by Fuel Type
4.	Schedule A4:	System Net Generation and Fuel Cost
5.	Schedule A5:	System Generated Fuel Cost Inventory Analysis
6.	Schedule A6:	Power Sold
7.	Schedule A7:	Purchased Power (Exclusive of Economy Energy Purchases)
8.	Schedule A8:	Energy Payments to Qualifying Facilities
9.	Schedule A9:	Economy Energy Purchases
10.	Schedule A12:	Capacity Contracts

Pursuant to the Order Establishing Procedure in this docket, electronic copies of the same will be provided to the parties under separate cover.

Sincerely,

Richard Hume

Richard Hume
Regulatory Issues Manager

md

Attachment

cc w/attachment: Florida Public Service Commission
Michael C. Barrett
Division of Auditing and Safety
Lynn Deamer

bc w/attachment: M. Goldstein
J. Grady
R. Hume
L. Roddy
M. Santos

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20200001-EI

MONTHLY FUEL FILING

December 2019

Gulf Power®

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: DECEMBER 2019

Line No.	Description	Reference		Amount
1	Fuel Cost of System Net Generation	Schedule A-3	$	17,038,546
2	Scherer/Flint Credit	Schedule A-3, Line 2b	$	(111,338)
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	$	-
4	Hedging Settlement Costs	Schedule A-2, Line A-5	$	669,990
5	Fuel Cost of Purchased Power	Schedule A-7	$	-
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	$	14,032,360
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	$	-
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 6	$	387,931
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7	$	(7,846,279)
10	Total Fuel and Net Power Transactions		$	24,171,209

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
		Dollars				KWH				Cents/kWh			
				Difference				Difference				Difference	
Line No.	Description	Actual	Estimated	Amount	%	Actual	Estimated	Amount	%	Actual	Estimated	Amount	%
1	Fuel Cost of System Net Generation (A3)	17,038,546	20,844,889	(3,806,343)	(18.26)	699,680,120	765,249,000	(65,568,880)	(8.57)	2.4352	2.7239	(0.29)	(10.60)
1a	Hedging Settlement Costs (A2)	669,990	619,640	50,350	8.13								
1b	Scherer/Flint Credit	(111,338)	(599,953)	488,615	(81.44)	(3,003,550)	(21,894,000)	18,890,450	(86.28)	3.7069	2.7403	0.97	35.27
2	Adjustments to Fuel Cost (A2, Page 1) **	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
3	TOTAL COST OF GENERATED POWER	17,597,198	20,864,576	(3,267,378)	(15.66)	696,676,570	743,355,000	(46,678,430)	(6.28)	2.5259	2.8068	(0.28)	(10.01)
4	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
5	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	14,032,360	17,905,853	(3,873,493)	(21.63)	539,065,726	646,101,000	(107,035,274)	(16.57)	2.6031	2.7714	(0.17)	(6.07)
6	Energy Payments to Qualifying Facilities (A8)	387,931	0	387,931	100.00	18,505,583	0	18,505,583	100.00	2.0963	0.0000	2.10	0.00
7	TOTAL COST OF PURCHASED POWER	14,420,290	17,905,853	(3,485,563)	(19.47)	557,571,309	646,101,000	(88,529,691)	(13.70)	2.5863	2.7714	(0.19)	(6.68)
8	Total Available kWh (Line 3 + Line 7)	32,017,489	38,770,429	(6,752,940)	(17.42)	1,254,247,879	1,389,456,000	(135,208,121)	(9.73)	2.5527	2.7903	(0.24)	(8.52)
9	Fuel Cost of Economy Sales (A6)	(111,241)	(287,346)	176,105	(61.29)	(6,268,602)	(11,859,000)	5,590,398	(47.14)	(1.7746)	(2.4230)	0.65	26.76
10	Gain on Economy Sales (A6)	(14,487)	(18,000)	3,513	(19.52)								
11	Fuel Cost of Other Power Sales (A6)	(7,720,552)	(11,035,078)	3,314,527	(30.04)	(400,193,599)	(480,458,000)	80,264,401	(16.71)	(1.9292)	(2.2968)	0.37	16.00
12	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 9 + 10 + 11)	(7,846,279)	(11,340,424)	3,494,145	(30.81)	(406,462,201)	(492,317,000)	85,854,799	(17.44)	(1.9304)	(2.3035)	0.37	16.20
13	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 3 + 7 + 12)	24,171,209	27,430,005	(3,258,796)	(11.88)	847,785,678	897,139,000	(49,353,322)	(5.50)	2.8511	3.0575	(0.21)	(6.75)
14	Company Use *	34,621	38,647	(4,026)	(10.42)	1,214,312	1,264,000	(49,688)	(3.93)	2.8511	3.0575	(0.21)	(6.75)
15	T & D Losses *	1,534,818	1,336,708	198,110	14.82	53,832,478	43,719,000	10,113,478	23.13	2.8511	3.0575	(0.21)	(6.75)
16	TERRITORIAL KWH SALES	24,171,210	27,430,005	(3,258,796)	(11.88)	792,738,888	852,156,000	(59,417,112)	(6.97)	3.0491	3.2189	(0.17)	(5.28)
17	Wholesale kWh Sales	705,703	808,719	(103,016)	(12.74)	23,144,515	25,124,000	(1,979,485)	(7.88)	3.0491	3.2189	(0.17)	(5.28)
18	Jurisdictional kWh Sales	23,465,507	26,621,286	(3,155,779)	(11.85)	769,594,373	827,032,000	(57,437,627)	(6.95)	3.0491	3.2189	(0.17)	(5.28)
19	Jurisdictional Loss Multiplier	1.0012	1.0012							1.0012	1.0012		
20	Jurisdictional kWh Sales Adj. for Line Losses	23,493,666	26,653,232	(3,159,566)	(11.85)	769,594,373	827,032,000	(57,437,627)	(6.95)	3.0527	3.2228	(0.17)	(5.28)
21	TRUE-UP	(1,950,778)	(1,950,778)	0	0.00	769,594,373	827,032,000	(57,437,627)	(6.95)	(0.2535)	(0.2359)	(0.02)	7.46
22	TOTAL JURISDICTIONAL FUEL COST	21,542,888	24,702,454	(3,159,566)	(12.79)	769,594,373	827,032,000	(57,437,627)	(6.95)	2.7992	2.9869	(0.19)	(6.28)
23	Revenue Tax Factor									1.00072	1.00072		
24	Fuel Factor Adjusted for Revenue Taxes									2.8012	2.9891	(0.19)	(6.29)
25	GPIF Reward / (Penalty)	(21,406)	(21,406)	0	0.00	769,594,373	827,032,000	(57,437,627)	(6.95)	(0.0028)	(0.0026)	(0.00)	7.69
26	Tax Savings Credit	(674,590)	(674,590)	0	0.00	769,594,373	827,032,000	(57,437,627)	(6.95)	(0.0877)	(0.0816)	(0.01)	7.48
27	Fuel Factor Adjusted for GPIF Reward / (Penalty) & Tax Savings Credit									2.7107	2.9049	(0.19)	(6.69)
28	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									2.711	2.905		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2019
PERIOD TO DATE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
		Dollars				KWH				Cents/kWh			
				Difference				Difference				Difference	
Line No.	Description	Actual	Estimated	Amount	%	Actual	Estimated	Amount	%	Actual	Estimated	Amount	%
1	Fuel Cost of System Net Generation (A3)	250,035,418	271,536,996	(21,501,578)	(7.92)	8,365,895,210	9,431,639,000	(1,065,743,790)	(11.30)	2.9887	2.8790	0.11	3.81
1a	Hedging Settlement Costs (A2)	7,178,070	7,577,430	(399,360)	(5.27)								
1b	Scherer/Flint Credit	(4,690,362)	(5,597,528)	907,166	(16.21)	(158,252,927)	(203,256,000)	45,003,073	(22.14)	2.9638	2.7539	0.21	7.62
2	Adjustments to Fuel Cost (A2, Page 1) **	(479,975)	0	(479,975)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	TOTAL COST OF GENERATED POWER	252,043,152	273,516,898	(21,473,746)	(7.85)	8,207,642,283	9,228,383,000	(1,020,740,717)	(11.06)	3.0708	2.9639	0.11	3.61
4	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
5	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	196,711,972	208,634,043	(11,922,071)	(5.71)	6,856,102,692	7,354,539,000	(498,436,308)	(6.78)	2.8692	2.8368	0.03	1.14
6	Energy Payments to Qualifying Facilities (A8)	6,103,667	0	6,103,667	100.00	231,189,925	0	231,189,925	100.00	2.6401	0.0000	2.64	0.00
7	TOTAL COST OF PURCHASED POWER	202,815,639	208,634,043	(5,818,404)	(2.79)	7,087,292,617	7,354,539,000	(267,246,383)	(3.63)	2.8617	2.8368	0.02	0.88
8	Total Available kWh (Line 3 + Line 7)	454,858,791	482,150,941	(27,292,150)	(5.66)	15,294,934,900	16,582,922,000	(1,287,987,100)	(7.77)	2.9739	2.9075	0.07	2.28
9	Fuel Cost of Economy Sales (A6)	(1,556,684)	(2,757,820)	1,201,136	(43.55)	(63,631,105)	(112,848,000)	49,216,895	(43.61)	(2.4464)	(2.4438)	(0.00)	(0.11)
10	Gain on Economy Sales (A6)	(159,395)	(162,000)	2,605	(1.61)								
11	Fuel Cost of Other Power Sales (A6)	(78,087,489)	(109,436,647)	31,349,159	(28.65)	(3,236,198,314)	(4,727,153,000)	1,490,954,686	(31.54)	(2.4129)	(2.3151)	(0.10)	(4.22)
12	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 9 + 10 + 11)	(79,803,568)	(112,356,467)	32,552,900	(28.97)	(3,299,829,419)	(4,840,001,000)	1,540,171,581	(31.82)	(2.4184)	(2.3214)	(0.10)	(4.18)
13	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 3 + 7 + 12)	375,055,224	369,794,473	5,260,751	1.42	11,995,105,481	11,742,921,000	252,184,481	2.15	3.1267	3.1491	(0.02)	(0.71)
14	Company Use *	412,852	482,977	(70,125)	(14.52)	13,204,092	15,337,000	(2,132,908)	(13.91)	3.1267	3.1491	(0.02)	(0.71)
15	T & D Losses *	18,813,183	18,112,175	701,008	3.87	601,694,540	575,154,000	26,540,540	4.61	3.1267	3.1491	(0.02)	(0.71)
16	TERRITORIAL KWH SALES	375,055,223	369,794,473	5,260,750	1.42	11,380,206,850	11,152,430,000	227,776,850	2.04	3.2957	3.3158	(0.02)	(0.61)
17	Wholesale kWh Sales	9,932,963	9,981,954	(48,991)	(0.49)	301,338,164	300,774,000	564,164	0.19	3.2963	3.3188	(0.02)	(0.68)
18	Jurisdictional kWh Sales	365,122,260	359,812,519	5,309,741	1.48	11,078,868,686	10,851,656,000	227,212,686	2.09	3.2957	3.3157	(0.02)	(0.60)
19	Jurisdictional Loss Multiplier	1.0012	1.0012							1.0012	1.0012		
20	Jurisdictional kWh Sales Adj. for Line Losses	365,560,406	360,244,295	5,316,111	1.48	11,078,868,686	10,851,656,000	227,212,686	2.09	3.2996	3.3197	(0.02)	(0.61)
21	TRUE-UP	(23,409,339)	(23,409,339)	0	0.00	11,078,868,686	10,851,656,000	227,212,686	2.09	(0.2113)	(0.2157)	0.00	(2.04)
22	TOTAL JURISDICTIONAL FUEL COST	342,151,067	336,834,956	5,316,111	1.58	11,078,868,686	10,851,656,000	227,212,686	2.09	3.0883	3.1040	(0.02)	(0.51)
23	Revenue Tax Factor									1.00072	1.00072		
24	Fuel Factor Adjusted for Revenue Taxes									3.0905	3.1062	(0.02)	(0.51)
25	GPIF Reward / (Penalty)	(256,872)	(256,872)	0	0.00	11,078,868,686	10,851,656,000	227,212,686	2.09	(0.0023)	(0.0024)	0.00	(4.17)
26	Tax Savings Credit	(8,095,082)	(8,095,082)	0	0.00	11,078,868,686	10,851,656,000	227,212,686	2.09	(0.0731)	(0.0746)	0.00	(2.01)
27	Fuel Factor Adjusted for GPIF Reward / (Penalty) & Tax Savings Credit									3.0151	3.0292	(0.01)	(0.47)
28	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.015	3.029		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2019

Line No.	Description	CURRENT MONTH Actual	CURRENT MONTH Estimated	CURRENT MONTH Difference Amount	CURRENT MONTH Difference %	PERIOD-TO-DATE Actual	PERIOD-TO-DATE Estimated	PERIOD-TO-DATE Difference Amount	PERIOD-TO-DATE Difference %
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	16,854,437.06	20,688,685	(3,834,247.94)	(18.53)	248,040,299.42	269,464,835	(21,424,535.58)	(7.95)
1a	Other Generation	184,109.22	156,204	27,905.22	17.86	1,995,119.06	2,072,161	(77,041.94)	(3.72)
1b	Scherer/Flint Credit	(111,337.81)	(599,953)	488,614.73	(81.44)	(4,690,362.22)	(5,597,528)	907,165.97	(16.21)
2	Fuel Cost of Power Sold	(7,846,279.46)	(11,340,424)	3,494,144.54	30.81	(79,803,567.79)	(112,356,468)	32,552,900.21	28.97
3	Fuel Cost - Purchased Power	14,032,359.98	17,905,853	(3,873,493.02)	(21.63)	196,711,972.17	208,634,043	(11,922,070.83)	(5.71)
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	387,930.64	0	387,930.64	100.00	6,103,667.27	0	6,103,667.27	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	669,990.00	619,640	50,350.00	8.13	7,178,070.00	7,577,430	(399,360.00)	(5.27)
6	Total Fuel & Net Power Transactions	24,171,209.63	27,430,005	(3,258,795.83)	(11.88)	375,535,197.91	369,794,473	5,740,725.10	1.55
7	AdjustmentsTo Fuel Cost*	0.00	0.000	0.00	0.00	(479,974.52)	0	(479,974.52)	100.00
8	Adj. Total Fuel & Net Power Transactions	24,171,209.63	27,430,005	(3,258,795.83)	(11.88)	375,055,223.39	369,794,473	5,260,750.58	1.42
B.	*KWH Sales*								
1	Jurisdictional Sales	769,594,373	827,032,000	(57,437,627)	(6.95)	11,078,868,686	10,851,656,000	227,212,686	2.09
2	Non-Jurisdictional Sales	23,144,515	25,124,000	(1,979,485)	(7.88)	301,338,164	300,774,000	564,164	0.19
3	Total Territorial Sales	792,738,888	852,156,000	(59,417,112)	(6.97)	11,380,206,850	11,152,430,000	227,776,850	2.04
4	Juris. Sales as % of Total Terr. Sales	97.0804	97.0517	0.0287	0.03	97.3521	97.3031	0.0490	0.05

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2019

Line No.	Description	CURRENT MONTH Actual	Estimated	Difference Amount	%	PERIOD-TO-DATE Actual	Estimated	Difference Amount	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	23,355,380.32	25,041,040	(1,685,659.73)	(6.73)	336,275,528.29	328,568,607	7,706,920.89	2.35
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	1,950,778.00	1,950,778	0.00	0.00	23,409,339.00	23,409,339	0.00	0.00
2b	Incentive Provision	21,391.00	21,391	0.00	0.00	256,687.00	256,687	0.00	0.00
2c	Tax Savings Credit	674,590.00	674,590	0.00	0.00	8,095,082.00	8,095,082	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	26,002,139.32	27,687,799	(1,685,659.68)	(6.09)	368,036,636.29	360,329,715	7,706,921.29	2.14
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	24,171,209.63	27,430,005	(3,258,795.83)	(11.88)	375,055,223.39	369,794,473	5,260,750.58	1.42
5	Juris. Sales % of Total KWH Sales (Line B4)	97.0804	97.0517	0.0287	0.03	97.3521	97.3031	0.0490	0.05
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0012)	23,493,665.60	26,653,232	(3,159,566.40)	(11.85)	365,560,406.42	360,244,295	5,316,111.42	1.48
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	2,508,473.72	1,034,567	1,473,906.72	(142.47)	2,476,229.87	85,420	2,390,809.87	(2,798.89)
8	Interest Provision for the Month	10,144.75	1,086	9,058.75	(834.14)	328,637.83	257,303	71,334.83	(27.72)
9	Beginning True-Up & Interest Provision	6,749,097.82	1,257,848	5,491,249.82	(436.56)	27,921,409.59	23,409,339	4,512,070.59	(19.27)
10	True-Up Collected / (Refunded)	(1,950,778.00)	(1,950,778)	0.00	0.00	(23,409,339.00)	(23,409,339)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	7,316,938.29	342,723	6,974,215.29	(2,034.94)	7,316,938.29	342,723	6,974,215.29	(2,034.94)
12	Adjustment	884,823.77	0	884,823.77	100.00	884,823.77	0	884,823.77	100.00
13	End of Period - Total Net True-Up	8,201,762.06	342,723	7,859,039.06	(2,293.12)	8,201,762.06	342,723	7,859,039.06	(2,293.12)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2019

Line No.	Description	CURRENT MONTH Actual	Estimated	Difference Amount	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	6,749,097.82	1,257,848	5,491,249.82	436.56
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	8,191,617.31	341,637	7,849,980.31	2,297.75
3	Total of Beginning & Ending True-Up Amts.	14,940,715.13	1,599,485	13,341,230.13	834.10
4	Average True-Up Amount	7,470,357.57	799,743	6,670,614.57	834.09
	Interest Rate				
5	1st Day of Reporting Business Month	1.67	1.67	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	1.59	1.59	0.0000	
7	Total (D5+D6)	3.26	3.26	0.0000	
8	Annual Average Interest Rate	1.63	1.63	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.1358	0.1358	0.0000	
10	Interest Provision (D4*D9)	10,144.75	1,086	9,058.75	834.14
	Jurisdictional Loss Multiplier	1.0012	1.0012		

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2019

Line No.	Description	CURRENT MONTH Actual	CURRENT MONTH Estimated	CURRENT MONTH Difference Amount	CURRENT MONTH Difference %	PERIOD-TO-DATE Actual	PERIOD-TO-DATE Estimated	PERIOD-TO-DATE Difference Amount	PERIOD-TO-DATE Difference %
	FUEL COST-NET GEN.($)								
1	LIGHTER OIL (B.L.)	130,290	46,059	84,231	182.88	1,457,799	910,339	547,460	60.14
2	COAL	7,406,422	8,967,455	(1,561,033)	(17.41)	126,176,563	132,282,997	(6,106,434)	(4.62)
2a	Coal at Scherer	397,626	2,520,809	(2,123,183)	(84.23)	19,486,365	23,451,631	(3,965,266)	(16.91)
2b	Scherer/Flint Credit	(111,338)	(599,953)	488,615	(81.44)	(4,690,362)	(5,597,528)	907,166	(16.21)
3	GAS	9,017,263	9,142,282	(125,019)	(1.37)	100,624,974	112,907,556	(12,282,582)	(10.88)
4	GAS (B.L.)	14,583	93,876	(79,293)	(84.47)	1,364,039	1,118,283	245,756	21.98
5	LANDFILL GAS	72,362	74,408	(2,046)	(2.75)	807,022	809,234	(2,212)	(0.27)
6	OIL - C.T.	0	0	0	0.00	118,657	56,956	61,701	108.33
7	TOTAL ($)	16,927,208	20,244,936	(3,317,728)	(16.39)	245,345,056	265,939,468	(20,594,411)	(7.74)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	229,280	279,973	(50,693)	(18.11)	3,631,504	4,126,904	(495,400)	(12.00)
9a	Coal at Scherer	11,426	91,993	(80,567)	(87.58)	659,012	851,517	(192,505)	(22.61)
9b	Scherer/Flint Credit	(3,004)	(21,894)	18,890	(86.28)	(158,253)	(203,256)	45,003	(22.14)
10	GAS	456,025	391,186	64,839	16.57	4,051,499	4,428,263	(376,764)	(8.51)
11	LANDFILL GAS	2,101	2,097	4	0.19	22,740	24,699	(1,959)	(7.93)
12	SOLAR	858	0	858	100.00	858	0	858	100.00
13	OIL - C.T.	(10)	0	(10)	100.00	282	256	26	10.16
14	TOTAL (MWH)	696,676.570	743,355	(46,678)	(6.28)	8,207,642	9,228,383	(1,020,741)	(11.06)
	UNITS OF FUEL BURNED								
15	LIGHTER OIL (BBL)	1,424	513	911	177.67	16,736	9,847	6,889	69.96
16	COAL (TONS)	111,925	139,304	(27,379)	(19.65)	1,886,380	2,069,580	(183,200)	(8.85)
17	GAS (MCF) (1)	3,106,239	2,770,839	335,400	12.10	27,938,590	31,657,565	(3,718,975)	(11.75)
18	OIL - C.T. (BBL)	0	0	0	0.00	1,176	615	561	91.21
	BTU'S BURNED (MMBTU)								
19	COAL + GAS B.L. + OIL B.L.	2,625,333	3,794,848	(1,169,515)	(30.82)	44,404,113	52,003,185	(7,599,072)	(14.61)
20	GAS - Generation (1)	3,179,004	2,740,839	438,165	15.99	28,409,420	31,555,514	(3,146,094)	(9.97)
21	OIL - C.T.	0	0	0	0.00	6,131	3,601	2,530	70.26
22	TOTAL (MMBTU)	5,804,337	6,535,687	(731,350)	(11.19)	72,819,664	83,562,300	(10,742,636)	(12.86)
	GENERATION MIX (% MWH)								
23	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	COAL	34.12	47.10	(12.98)	(27.56)	50.35	51.74	(1.39)	(2.69)
25	GAS	65.46	52.62	12.84	24.40	49.36	47.99	1.37	2.85
26	LANDFILL GAS	0.30	0.28	0.02	7.14	0.28	0.27	0.01	3.70
27	SOLAR	0.12	0.00	0.12	100.00	0.01	0.00	0.01	100.00
28	OIL - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
30	LIGHTER OIL ($/BBL)	86.71	89.83	(3.12)	(3.47)	87.11	92.45	(5.34)	(5.78)
31	COAL ($/TON)	66.17	64.37	1.80	2.80	66.89	63.92	2.97	4.65
32	GAS ($/MCF) (1)	2.85	3.28	(0.43)	(13.11)	3.58	3.54	0.04	1.13
33	OIL - C.T. ($/BBL)	0.00	0.00	0.00	0.00	100.90	92.60	8.30	8.96
	FUEL COST ($) / MMBTU								
34	COAL + GAS B.L. + OIL B.L.	2.99	2.91	0.08	2.75	3.24	2.93	0.31	10.58
35	GAS - Generation (1)	2.78	3.28	(0.50)	(15.24)	3.47	3.51	(0.04)	(1.14)
36	OIL - C.T.	0.00	0.00	0.00	0.00	19.35	15.82	3.53	22.31
37	TOTAL ($/MMBTU)	2.87	3.06	(0.19)	(6.21)	3.33	3.15	0.18	5.71
	BTU BURNED / KWH								
38	COAL + GAS B.L. + OIL B.L.	11,045	10,840	205	1.89	10,746	10,890	(144)	(1.32)
39	GAS - Generation (1)	7,064	7,110	(46)	(0.65)	7,138	7,245	(107)	(1.48)
40	OIL - C.T.	0	0	0	0.00	21,741	14,066	7,675	54.56
41	TOTAL (BTU/KWH)	8,429	8,885	(456)	(5.13)	8,975	9,152	(177)	(1.93)
	FUEL COST (¢ / KWH)								
42	COAL + GAS B.L. + OIL B.L.	3.30	3.15	0.15	4.76	3.48	3.19	0.29	9.09
43	GAS	1.98	2.34	(0.36)	(15.38)	2.48	2.55	(0.07)	(2.75)
44	LANDFILL GAS	3.44	3.55	(0.11)	(3.10)	3.55	3.28	0.27	8.23
45	OIL - C.T.	0.00	0.00	0.00	0.00	42.08	22.25	19.83	89.12
46	TOTAL (¢/KWH)	2.43	2.72	(0.29)	(10.66)	2.99	2.88	0.11	3.82

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2019

(1) Line No.	(2) Plant/Unit & Fuel Type	(3) Net Cap. (MW)	(4) Net Gen. (MWh)	(5) Cap. Factor (%)	(6) Equiv. Avail. Factor (%)	(7) Net Output Factor (%)	(8) Avg. Net Heat Rate (Btu/kWh)	(9) Fuel Burned Units (Tons/MCF/Bbl)	(10) Fuel Heat Value (lbs./cf/Gal.)	(11) Fuel Burned (MMBtu)	(12) Fuel Burned Cost ($)	(13) Fuel Cost/kWh (¢/kWh)	(14) Fuel Cost/Unit ($/Unit)
1	Crist 4	75	(482)	0.0	100.0	0.0	N/A						
2	Coal		0					0	0	0	0	0.00	0.00
3	Gas-G		0					0	1,017	0	0	0.00	0.00
4	Gas-S							0	1,017	0	0		0.00
5	Oil-S							0	139,075	0	0		0.00
6	Crist 5	75	(482)	0.0	71.2	0.0	N/A						
7	Coal		0					0	0	0	0	0.00	0.00
8	Gas-G		0					0	1,017	0	0	0.00	0.00
9	Gas-S							0	1,017	0	0		0.00
10	Oil-S							0	139,075	0	0		0.00
11	Crist 6	299	0	4.6	35.9	66.3	12,104						
12	Coal		9,056					5,287	11,062	116,969	355,437	3.92	67.23
13	Gas-G		1,232					7,434	1,017	7,561	28,113	2.28	3.72
14	Gas-S							1,945	1,016	1,978	7,354		3.72
15	Oil-S							7	139,075	39	674		96.29
16	Crist 7	475	0	62.8	100.0	64.0	10,622						
17	Coal		211,338					98,648	11,381	2,245,425	6,631,959	3.14	67.23
18	Gas-G		10,567					109,843	1,016	111,710	415,366	3.93	3.72
19	Gas-S							1,912	1,016	1,944	7,229		3.72
20	Oil-S							235	139,075	1,373	23,603		100.44
21	Smith 3	604	439,216	97.7	100.0	97.7	6,966						
22	Gas-G							2,985,105	1,025	3,059,733	8,389,676	1.91	2.81
23	Smith A (1)	36	(10)	0.0	100.0	0.0	0						
24	Oil							0	138,388	0	0	0.00	0.00
25	Scherer 3 (2)	216	11,426	7.1	100.0	34.2	13,063						
26	Coal								8,523	149,257	397,626	3.48	0.00
27	Oil							300	138,500	1,743	25,931	0.00	86.44
28	Scherer/Flint Credit	(57)	(3,004)	N/A	N/A	N/A	N/A						
29	Coal								N/A	(39,234)	(104,522)	N/A	N/A
30	Oil							(79)	N/A	(458)	(6,816)	N/A	N/A
31	Other Generation		5,973										
32	Gas										184,109	3.08	0.00
33	Perdido		2,101										
34	Landfill Gas										72,362	3.44	0.00
35	Blue Indigo		858										
36	Solar												
37	Daniel 1 (3)	251	(1,888)	0.0	100.0	0.0	0						
38	Coal							7,990	8,806	140,720	423,048	0.00	52.95
39	Oil-S							0	138,101	0	0		0.00
40	Daniel 2 (3)	251	10,775	5.8	45.8	10.4	0						
41	Coal							0	0	0	0	0.00	0.00
42	Oil-S							961	138,101	5,577	80,081		83.33
43	Total	2,225	696,677	42.1	86.9	53.6	8,429			5,804,337	16,931,230	2.43	

Notes & Adjustments:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership
Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Adj. Units	Adj Description	Adj $	cents/kWh
N/A	Daniel Railcar Track Deprec.	(4,022)	

Recoverable Fuel	**16,927,208**	**2.43**

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2019

Line No.	Description	CURRENT MONTH Actual	CURRENT MONTH Estimated	CURRENT MONTH Difference Amount	CURRENT MONTH Difference %	PERIOD-TO-DATE Actual	PERIOD-TO-DATE Estimated	PERIOD-TO-DATE Difference Amount	PERIOD-TO-DATE Difference %
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	1,371	516	855	165.70	18,014	9,747	8,267	84.82
3	UNIT COST ($/BBL)	96.26	91.70	4.56	4.97	79.53	94.94	(15.41)	(16.23)
4	AMOUNT ($)	131,974	47,315	84,659	178.93	1,432,742	925,370	507,372	54.83
5	*BURNED :*								
6	UNITS (BBL)	1,519	513	1,006	196.19	17,041	9,847	7,194	73.06
7	UNIT COST ($/BBL)	86.71	89.83	(3.12)	(3.47)	85.51	92.45	(6.94)	(7.51)
8	AMOUNT ($)	131,717	46,059	85,658	185.97	1,457,201	910,339	546,862	60.07
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	5,431	6,857	(1,426)	(20.80)	5,431	6,857	(1,426)	(20.80)
11	UNIT COST ($/BBL)	87.17	87.51	(0.34)	(0.39)	87.17	87.51	(0.34)	(0.39)
12	AMOUNT ($)	473,431	600,115	(126,684)	(21.11)	473,431	600,115	(126,684)	(21.11)
13	DAYS SUPPLY	N/A	N/A						
	COAL EXCLUDING PLANT SCHERER								
14	*PURCHASES :*								
15	UNITS (TONS)	121,473	187,000	(65,527)	(35.04)	2,026,124	2,182,500	(156,376)	(7.16)
16	UNIT COST ($/TON)	54.29	64.27	(9.98)	(15.53)	63.78	63.30	0.48	0.76
17	AMOUNT ($)	6,595,217	12,018,666	(5,423,449)	(45.13)	129,216,964	138,161,117	(8,944,153)	(6.47)
18	*BURNED :*								
19	UNITS (TONS)	111,925	139,304	(27,379)	(19.65)	1,886,380	2,069,580	(183,200)	(8.85)
20	UNIT COST ($/TON)	63.92	64.37	(0.45)	(0.70)	64.55	63.92	0.63	0.99
21	AMOUNT ($)	7,154,563	8,967,455	(1,812,892)	(20.22)	121,761,820	132,282,997	(10,521,177)	(7.95)
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	521,218	519,211	2,007	0.39	521,218	519,211	2,007	0.39
24	UNIT COST ($/TON)	56.87	62.29	(5.42)	(8.70)	56.87	62.29	(5.42)	(8.70)
25	AMOUNT ($)	29,639,315	32,340,972	(2,701,657)	(8.35)	29,639,315	32,340,972	(2,701,657)	(8.35)
26	DAYS SUPPLY	33	33						
	COAL AT PLANT SCHERER								
27	*PURCHASES :*								
28	UNITS (MMBTU)	552,764	1,264,670	(711,906)	(56.29)	8,329,466	9,852,120	(1,522,654)	(15.46)
29	UNIT COST ($/MMBTU)	2.71	2.56	0.15	5.86	2.70	2.57	0.13	5.06
30	AMOUNT ($)	1,500,265	3,242,610	(1,742,345)	(53.73)	22,488,440	25,283,060	(2,794,620)	(11.05)
31	*BURNED :*								
32	UNITS (MMBTU)	149,257	979,127	(829,870)	(84.76)	7,224,272	9,106,540	(1,882,268)	(20.67)
33	UNIT COST ($/MMBTU)	2.66	2.57	0.09	3.50	2.70	2.58	0.12	4.65
34	AMOUNT ($)	397,626	2,520,809	(2,123,183)	(84.23)	19,493,139	23,451,631	(3,958,492)	(16.88)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	3,068,809	2,686,667	382,142	14.22	3,068,809	2,686,667	382,142	14.22
37	UNIT COST ($/MMBTU)	2.66	2.60	0.06	2.31	2.66	2.60	0.06	2.31
38	AMOUNT ($)	8,176,037	6,998,696	1,177,341	16.82	8,176,037	6,998,696	1,177,341	16.82
39	DAYS SUPPLY	57	50						

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2019

Line No.	Description	CURRENT MONTH Actual	Estimated	Difference Amount	%	PERIOD-TO-DATE Actual	Estimated	Difference Amount	%
	GAS	(Reported on a MMBTU and $ basis)							
40	*PURCHASES :*								
41	UNITS (MMBTU)	3,249,760	2,770,839	478,921	17.28	28,477,674	31,885,514	(3,407,840)	(10.69)
42	UNIT COST ($/MMBTU)	2.67	3.28	(0.61)	(18.60)	3.45	3.51	(0.06)	(1.71)
43	AMOUNT ($)	8,673,849	9,079,954	(406,105)	(4.47)	98,205,090	111,781,307	(13,576,217)	(12.15)
44	*BURNED :*								
45	UNITS (MMBTU)	3,182,926	2,770,839	412,087	14.87	28,528,283	31,885,514	(3,357,231)	(10.53)
46	UNIT COST ($/MMBTU)	2.78	3.28	(0.50)	(15.24)	3.51	3.51	0.00	0.00
47	AMOUNT ($)	8,847,737	9,079,954	(232,217)	(2.56)	99,993,893	111,781,307	(11,787,414)	(10.55)
48	*ENDING INVENTORY :*								
48	UNITS (MMBTU)	808,302	0	808,302	100.00	808,302	0	808,302	100.00
50	UNIT COST ($/MMBTU)	2.75	0.00	2.75	100.00	2.75	0.00	2.75	100.00
51	AMOUNT ($)	2,221,201	0	2,221,201	100.00	2,221,201	0	2,221,201	100.00
	OTHER - C.T. OIL								
52	*PURCHASES :*								
53	UNITS (BBL) *	4	0	4	100.00	305	0	305	100.00
54	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	(27.02)	0.00	(27.00)	100.00
55	AMOUNT ($)	0	0	0	0.00	(8,241)	0	(8,241)	100.00
56	*BURNED :*								
57	UNITS (BBL)	0	0	0	0.00	1,176	615	561	91.22
58	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	93.89	92.61	1.28	1.38
59	AMOUNT ($)	0	0	0	0.00	110,416	56,956	53,460	93.86
60	*ENDING INVENTORY :*								
61	UNITS (BBL)	6,591	6,376	215	3.37	6,591	6,376	215	3.37
62	UNIT COST ($/BBL)	92.26	92.69	(0.43)	(0.46)	92.26	92.69	(0.43)	(0.46)
63	AMOUNT ($)	608,066	590,980	17,086	2.89	608,066	590,980	17,086	2.89
64	HOURS SUPPLY	75	72						

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2019

CURRENT MONTH

Line No.	Sold To	Type and Schedule	Total KWH Sold	KWH Wheeled from Other Systems	KWH from Own Generation	¢ / kWh Fuel Costs	¢ / kWh Total Costs	Total $ for Fuel Adjustment	Total Cost ($)
	ESTIMATED								
1	Southern Company Interchange		480,458,000	0	480,458,000	2.30	2.69	11,035,078	12,923,125
2	Various	Economy Sales	11,859,000	0	11,859,000	2.42	2.78	287,346	329,788
3		Gain on Econ. Sales	0	0	0	0.00	0.00	18,000	18,000
4	TOTAL ESTIMATED SALES		492,317,000	0	492,317,000	2.30	2.70	11,340,424	13,270,913
	ACTUAL								
5	Southern Company Interchange		406,462,261	0	406,462,261	1.93	2.13	7,831,661	8,637,982
6	A.E.C.	External	246,398	0	246,398	1.90	2.70	4,676	6,642
7	DUKE PWR	External	563,112	0	563,112	1.74	2.50	9,775	14,060
8	EAGLE EN	External	391,980	0	391,980	1.92	2.68	7,526	10,508
9	ENDURE	External	0	0	0	0.00	0.00	0	0
10	EXELON	External	233,700	0	233,700	1.71	2.39	3,998	5,594
11	FPC	External	100,646	0	100,646	1.52	2.12	1,532	2,133
12	FPL	External	0	0	0	0.00	0.00	0	0
13	MACQUARI	External	74,346	0	74,346	2.30	3.48	1,711	2,586
14	MERCURIA	External	191,696	0	191,696	2.56	3.65	4,904	6,997
15	MISO	External	2,018,544	0	2,018,544	1.52	2.15	30,725	43,373
16	MORGAN	External	46,129	0	46,129	1.99	2.38	920	1,097
17	NCEMC	External	0	0	0	0.00	0.00	0	0
18	NCMPA1	External	0	0	0	0.00	0.00	0	0
19	NTE	External	0	0	0	0.00	0.00	0	0
20	OPC	External	38,939	0	38,939	2.36	3.60	919	1,402
21	ORLANDO	External	0	0	0	0.00	0.00	0	0
22	PJM	External	439,130	0	439,130	1.92	2.80	8,443	12,279
23	REMC	External	7,907	0	7,907	2.54	3.50	201	276
24	SCE&G	External	0	0	0	0.00	0.00	0	0
25	SEPA	External	682,053	0	682,053	2.23	2.97	15,232	20,283
26	TAL	External	0	0	0	0.00	0.00	0	0
27	TEA	External	1,126,790	0	1,126,790	1.64	2.36	18,523	26,620
28	TECO	External	0	0	0	0.00	0.00	0	0
29	TVA	External	68,893	0	68,893	1.93	3.00	1,328	2,067
30	WRI	External	38,339	0	38,339	2.16	3.46	828	1,327
31	Less: Flow-Thru Energy		(6,268,662)	0	(6,268,662)	1.77	1.77	(111,109)	(111,109)
32	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	14,487	14,487
33	TOTAL ACTUAL SALES		406,462,201	0	406,462,201	1.93	2.14	7,846,279	8,684,118
34	Difference in Amount		(85,854,799)	0	(85,854,799)	(0.37)	0.00	(3,494,145)	(4,586,796)
35	Difference in Percent		(17.44)	0	(17.44)	(16.09)	0.00	(30.81)	(34.56)

Note: (1) Gains in the Total Cost column are included in the total cost for each counterparty, but shown separately on line 32 for informational purposes.

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2019

PERIOD TO DATE

Line No.	Sold To	Type and Schedule	Total KWH Sold	Kwh Wheeled from Other Systems	KWH from Own Generation	¢ / kWh Fuel Costs	¢ / kWh Total Costs	Total $ for Fuel Adjustment	Total Cost ($)
	ESTIMATED								
1	Southern Company Interchange		4,727,153,000	0	4,727,153,000	2.32	2.68	109,436,648	126,664,913
2	Various	Economy Sales	112,848,000	0	112,848,000	2.44	2.79	2,757,820	3,147,634
3		Gain on Econ. Sales	0	0	0	0.00	0.00	162,000	162,000
4	TOTAL ESTIMATED SALES		4,840,001,000	0	4,840,001,000	2.32	2.69	112,356,468	129,974,547
	ACTUAL								
5	Southern Company Interchange		3,299,829,479	0	3,299,829,479	2.41	2.63	79,535,854	86,826,386
6	A.E.C.	External	4,886,354	0	4,886,354	2.41	3.16	117,936	154,268
7	DUKE PWR	External	2,019,513	0	2,019,513	2.55	4.70	51,587	94,873
8	EAGLE EN	External	3,230,249	0	3,230,249	2.43	3.29	78,484	106,316
9	ENDURE	External	92,797	0	92,797	2.57	3.61	2,383	3,350
10	EXELON	External	3,305,938	0	3,305,938	2.36	2.86	78,052	94,501
11	FPC	External	1,088,581	0	1,088,581	2.47	3.61	26,837	39,350
12	FPL	External	3,839,893	0	3,839,893	3.05	4.73	117,091	181,626
13	MACQUARI	External	1,640,054	0	1,640,054	2.98	3.32	48,814	54,428
14	MERCURIA	External	670,936	0	670,936	10.24	3.18	68,736	21,315
15	MISO	External	10,266,076	0	10,266,076	1.95	2.58	199,935	265,343
16	MORGAN	External	1,719,772	0	1,719,772	2.92	3.92	50,179	67,500
17	NCEMC	External	14,679	0	14,679	3.12	4.20	459	617
18	NCMPA1	External	29,953	0	29,953	3.05	3.86	914	1,155
19	NTE	External	94,948	0	94,948	2.68	3.46	2,547	3,283
20	OPC	External	2,787,444	0	2,787,444	1.56	2.24	43,549	62,337
21	ORLANDO	External	230,646	0	230,646	3.01	4.60	6,950	10,609
22	PJM	External	2,387,705	0	2,387,705	2.49	3.51	59,457	83,782
23	REMC	External	793,334	0	793,334	3.82	3.37	30,288	26,758
24	SCE&G	External	61,643	0	61,643	3.20	5.97	1,973	3,682
25	SEPA	External	6,505,885	0	6,505,885	1.80	2.39	117,128	155,512
26	TAL	External	234,828	0	234,828	3.19	4.82	7,480	11,310
27	TEA	External	14,070,721	0	14,070,721	2.32	3.18	326,211	447,459
28	TECO	External	548,874	0	548,874	2.99	4.96	16,395	27,201
29	TVA	External	2,525,309	0	2,525,309	2.54	3.52	64,234	88,958
30	WRI	External	584,973	0	584,973	6.68	3.21	39,064	18,806
31	Less: Flow-Thru Energy		(63,631,165)	0	(63,631,165)	2.28	2.28	(1,448,365)	(1,448,365)
32	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	159,395	159,393
33	TOTAL ACTUAL SALES		3,299,829,419	0	3,299,829,419	2.42	2.65	79,803,568	87,402,358
34	Difference in Amount		(1,540,171,581)	0	(1,540,171,581)	0.10	(0.04)	(32,552,900)	(42,572,189)
35	Difference in Percent		(31.82)	0	(31.82)	4.31	(1.49)	(28.97)	(32.75)

Note: (1) Gains in the Total Cost column are included in the total cost for each counterparty, but shown separately on line 32 for informational purposes.

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
								¢ / kWh		
Line No.	Month	Purchased From	Type & Schedule	Total KWH Purchased	KWH for Other Utilities	KWH for Interruptible	KWH for Firm	Fuel Cost	Total Cost	Total $ for Fuel Adj
1	*ESTIMATED:*									
2	NONE									
3	*ACTUAL:*									
4	NONE									

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2019

CURRENT MONTH

Line No.	Purchased From	Type & Schedule	Total KWH Purchased	KWH for Other Utilities	KWH for Interruptible	KWH for Firm	¢ / kWh Fuel Cost	¢ / kWh Total Cost	Total $ for Fuel Adj
	ACTUAL								
1	Bay County/Engen, LLC	Contract	467,000	0	0	0	3.11	3.11	14,547
2	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	10,040
3	Ascend Performance Materials	COG 1	18,030,887	0	0	0	2.01	2.01	363,206
4	International Paper	COG 1	7,696	0	0	0	1.79	1.79	138
5	TOTAL		18,505,583	0	0	0	2.10	2.10	387,931

PERIOD-TO-DATE

Line No.	Purchased From	Type & Schedule	Total KWH Purchased	KWH for Other Utilities	KWH for Interruptible	KWH for Firm	¢ / kWh Fuel Cost	¢ / kWh Total Cost	Total $ for Fuel Adj
	ACTUAL								
6	Bay County/Engen, LLC	Contract	31,987,000	0	0	0	3.11	3.11	996,090
7	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	11,567
8	Ascend Performance Materials	COG 1	198,163,197	0	0	0	2.56	2.56	5,063,147
9	International Paper	COG 1	1,039,728	0	0	0	3.16	3.16	32,864
10	TOTAL		231,189,925	0	0	0	2.64	2.64	6,103,667

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2019

Line No.	Purchased From	CURRENT MONTH Total KWH Purchased	CURRENT MONTH Trans. Costs ¢ / KWH	CURRENT MONTH Total $ for Fuel Adj	PERIOD - TO - DATE Total KWH Purchased	PERIOD - TO - DATE Trans. Costs ¢ / KWH	PERIOD - TO - DATE Total $ for Fuel Adj
	ESTIMATED						
1	Southern Company Interchange	362,000	2.82	10,198	197,530,000	2.29	4,523,970
2	Economy Energy	3,611,000	2.79	100,655	56,608,000	2.75	1,557,073
3	Other Purchases	642,128,000	2.77	17,795,000	7,100,401,000	2.85	202,553,000
4	TOTAL ESTIMATED PURCHASES	646,101,000	2.77	17,905,853	7,354,539,000	2.84	208,634,043
	ACTUAL						
5	Southern Company Interchange	24,280,331	1.63	395,703	625,633,940	2.68	16,767,556
6	Non-Associated Companies	4,028,669	2.36	95,025	188,140,367	3.23	6,073,738
7	Purchased Power Agreements	425,757,000	2.38	10,122,906	4,832,753,000	2.56	123,725,670
8	Renewable Energy Purchase Agreements	87,892,777	4.02	3,529,230	1,263,087,268	4.08	51,578,356
9	Other Wheeled Energy	3,315,011	N/A	N/A	9,409,482	N/A	N/A
10	Other Transactions	60,600	N/A	13,935	709,800	N/A	157,504
11	Less: Flow-Thru Energy	(6,268,662)	1.99	(124,440)	(63,631,165)	2.50	(1,590,853)
12	TOTAL ACTUAL PURCHASES	539,065,726	2.60	14,032,360	6,856,102,692	2.87	196,711,972
13	Difference in Amount	(107,035,274)	(0.17)	(3,873,493)	(498,436,308)	0.03	(11,922,071)
14	Difference in Percent	(16.57)	(6.14)	(21.63)	(6.78)	1.06	(5.71)

2019 CAPACITY CONTRACTS
GULF POWER COMPANY

Capacity Costs ($)

A.	CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	TERM End	January	February	March	April	May	June	July	August	September	October	November	December	YTD
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Power Purchase Agreements & Other Confidential Agreements				7,185,428	7,197,644	7,178,454	7,177,822	7,263,198	7,195,836	7,075,296	7,076,269	7,076,269	7,076,269	7,076,269	6,973,698	85,552,452
				Total	7,185,428	7,197,644	7,178,454	7,177,822	7,263,198	7,195,836	7,075,296	7,076,269	7,076,269	7,076,269	7,076,269	6,973,698	85,552,452

Capacity Costs (MW)

B.	CONTRACT/COUNTERPARTY	TYPE	Start	End	January	February	March	April	May	June	July	August	September	October	November	December
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0	0	0	0	0
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies

Acronym	Definition
MWH	Megawatt Hour
KWH	Kilowatt Hour
T&D	Transmission & Distribution
Adj.	Adjusted
GPIF	Generating Performance Incentive Factor
Terr.	Territorial
Adj. Revs.	Adjusted Revenues
Juris.	Jurisdictional
B.L.	Boiler Lighter
BBL	Oil Barrel
C.T.	Combustion Turbine
cf	Cubic feet
MCF	Thousand cubic feet
BTU	British Thermal Unit
MMBTU	Million British Thermal Units
lbs.	Pounds
Gal.	Gallons
Deprec.	Depreciation
Econ.	Economy
COG	Cogeneration
Co-op	Cooperative

A-6 Counterparties

Party	Name
AEC	PowerSouth Energy Cooperative
AECI	Associated Electric Cooperative Inc.
CARGILE	Cargill Power Markets, LLC
DUKE PWR	Duke Energy Corporation
EAGLE EN	EDF Trading North America, LLC
ENDURE	Endure Energy, LLC
EXELON	Exelon Generation Company
FPC	Duke Energy Florida
FPL	Florida Power & Light Company
MACQUARI	Macquarie Group
MERCURIA	Mercuria Energy Group
MISO	Midwest Independent System Operator, Inc.
MORGAN	Morgan Stanley Capital Group
NCEMC	North Carolina Electric Membership Corporation
NOBLEAGP	Noble Americas Gas and Power Corporation
OPC	Oglethorpe Power Corporation
ORLANDO	Orlando Utilities Commission
PJM	PJM Interconnection LLC.
REMC	Rainbow Energy Marketing Corporation
SCE&G	South Carolina Electric & Gas
SEC	Seminole Electric Cooperative
SEPA	Southeastern Power Administration
TAL	City of Tallahassee
TEA	The Energy Authority
TECO	Tampa Electric Company
TENASKA	Tenaska
TVA	Tennessee Valley Authority
WRI	Westar Energy

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: **Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor**)))

Docket No.: **20200001-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by electronic mail this 21st day of January, 2020 to the following:

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Schedule CCE-1E

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP

TO BE INCLUDED IN THE PERIOD JANUARY 2021 - DECEMBER 2021

Line No.	Description	Total
1	Estimated over/(under)-recovery, January 2020 - December 2020 (Schedule CCE-1B, line 16 + 19)	$ (2,700,587)
2	Final over/(under)-recovery, January 2019 - December 2019 (Exhibit RLH-1, Schedule CCA-1, line 3)	452,844
3	Total Over/(Under)-Recovery (Line 1 + 2) (To be included in January 2021 - December 2021)	$ (2,247,743)
4	Jurisdictional kWh sales, January 2021 - December 2021	10,730,068,000
5	True-up Factor (Line 3 / Line 4) x 100 (¢/kWh)	0.0209

SCHEDULE CCE-1B

Gulf Power Company
Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
ACTUAL FOR THE PERIOD JANUARY 2020 - JUNE 2020 / ESTIMATED FOR JULY 2020 - DECEMBER 2020

Line No.	Line Description	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	23,120	17,509	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	9,985
2	Other Capacity Payments / (Receipts)	7,078,291	7,078,291	7,078,291	7,078,291	7,078,291	7,078,291	7,151,585	7,151,585	7,151,585	7,151,585	7,151,585	7,151,585	85,379,260
3	Transmission Revenue	(325)	(1,191)	(384)	(387)	(538)	(410)	(7,000)	(8,000)	(6,000)	(7,000)	(6,000)	(9,000)	(46,235)
4	Scherer/Flint Credit	(10)	0	0	2,136	0	0	0	0	0	0	0	0	2,125
5	Total Capacity Payments/(Receipts)	7,101,077	7,094,610	7,074,843	7,076,976	7,074,689	7,074,817	7,141,521	7,140,521	7,142,521	7,141,521	7,142,521	7,139,521	85,345,135
6	Jurisdictional %	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
7	Jurisdictional Capacity Payments/(Receipts)	6,904,680	6,898,392	6,879,172	6,881,246	6,879,022	6,879,147	6,944,005	6,943,033	6,944,978	6,944,005	6,944,978	6,942,061	82,984,719
8	Retail KWH Sales							1,158,517,000	1,145,167,000	995,494,000	839,046,000	731,278,000	817,367,000	
9	Purchased Power Capacity Cost Recovery Factor (¢/KWH)							0.765	0.765	0.765	0.765	0.765	0.765	
10	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	6,025,605	5,404,285	5,590,075	5,803,198	6,584,823	7,679,408	8,862,655	8,760,528	7,615,529	6,418,702	5,594,277	6,252,858	80,591,942
11	Revenue Taxes (Line 9 x .00072) ($)	4,338	3,891	4,025	4,178	4,741	5,529	6,381	6,308	5,483	4,621	4,028	4,502	58,026
12	True-Up Provision ($)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(237,948)
13	Capacity Cost Recovery Revenues net of Revenue Taxes	6,001,438	5,380,565	5,566,221	5,779,191	6,560,253	7,654,049	8,836,445	8,734,391	7,590,217	6,394,252	5,570,420	6,228,527	80,295,968
14	Over/(Under) Recovery (Line 12 - Line 6) ($)	(903,242)	(1,517,827)	(1,312,951)	(1,102,055)	(318,769)	774,902	1,892,440	1,791,358	645,239	(549,754)	(1,374,558)	(713,534)	(2,688,751)
15	Interest Provision ($)	(305)	(1,890)	(4,423)	(3,791)	(273)	(392)	(335)	(134)	0	7	(95)	(205)	(11,836)
16	Total Estimated True-Up for the Period													(2,700,587)
17	Beginning Balance True-Up & Interest Provision ($)	214,896	(668,822)	(2,168,710)	(3,466,255)	(4,552,272)	(4,851,485)	(4,057,146)	(2,145,212)	(334,159)	330,909	(199,009)	(1,553,833)	
18	True-Up Collected/(Refunded) ($)	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	
19	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	
20	End of Period TOTAL Net True-Up (Lines 13 + 14 + 16 + 17 + 18) ($)	(668,822)	(2,168,710)	(3,466,255)	(4,552,272)	(4,851,485)	(4,057,146)	(2,145,212)	(334,159)	330,909	(199,009)	(1,553,833)	(2,247,743)	

SCHEDULE CCE-2

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
ACTUAL FOR THE PERIOD JANUARY 2020 - JUNE 2020 / ESTIMATED FOR JULY 2020 - DECEMBER 2020

Line No.	Line Description	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1.	IIC Payments / (Receipts) ($)	23,120	17,509	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	9,985
2.	Other Capacity Payments / (Receipts)	7,078,291	7,078,291	7,078,291	7,078,291	7,078,291	7,078,291	7,151,585	7,151,585	7,151,585	7,151,585	7,151,585	7,151,585	85,379,260
3.	Transmission Revenue ($)	(325)	(1,191)	(384)	(387)	(538)	(410)	(7,000)	(8,000)	(6,000)	(7,000)	(6,000)	(9,000)	(46,235)
4.	Scherer/Flint Credit	(10)	-	-	2,136	-	-	-	-	-	-	-	-	2,125
5.	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	7,101,077	7,094,610	7,074,843	7,076,976	7,074,689	7,074,817	7,141,521	7,140,521	7,142,521	7,141,521	7,142,521	7,139,521	85,345,135
6.	Jurisdictional %	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
7.	Total Jurisdictional Recovery Amount (Line 4 * 5) ($)	6,904,680	6,898,392	6,879,172	6,881,246	6,879,022	6,879,147	6,944,005	6,943,033	6,944,978	6,944,005	6,944,978	6,942,061	82,984,719
8.	Jurisdictional Capacity Cost Recovery Revenues Net of Taxes ($)	6,021,267	5,400,394	5,586,050	5,799,020	6,580,082	7,673,878	8,856,274	8,754,220	7,610,046	6,414,080	5,590,249	6,248,356	80,533,917
9.	True-Up Provision ($)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(237,948)
10.	Jurisdictional Capacity Cost Recovery Revenue (Line 7 + 8) ($)	6,001,438	5,380,565	5,566,221	5,779,191	6,560,253	7,654,049	8,836,445	8,734,391	7,590,217	6,394,251	5,570,420	6,228,527	80,295,968
11.	Over/(Under) Recovery (Line 9 - 6) ($)	(903,242)	(1,517,827)	(1,312,951)	(1,102,055)	(318,769)	774,902	1,892,440	1,791,358	645,239	(549,754)	(1,374,558)	(713,534)	(2,688,751)
12.	Interest Provision ($)	(305)	(1,890)	(4,423)	(3,791)	(273)	(392)	(335)	(134)	-	7	(95)	(205)	(11,836)
13.	Beginning Balance True-Up & Interest Provision ($)	214,896	(668,822)	(2,168,710)	(3,466,255)	(4,552,272)	(4,851,485)	(4,057,146)	(2,145,212)	(334,159)	330,909	(199,009)	(1,553,833)	214,896
14.	True-Up Collected/(Refunded) ($)	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	237,948
15.	Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
16.	End of Period Total Net True-Up (Lines 10 + 11 + 12 + 13 + 14) ($)	(668,822)	(2,168,710)	(3,466,255)	(4,552,272)	(4,851,485)	(4,057,146)	(2,145,212)	(334,159)	330,909	(199,009)	(1,553,833)	(2,247,743)	(2,247,743)

SCHEDULE CCA-3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
ACTUAL FOR THE PERIOD JANUARY 2020 - JUNE 2020 / ESTIMATED FOR JULY 2020 - DECEMBER 2020

Line No.	Line Description	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1.	Beginning True-Up Amount ($)	214,896	(668,822)	(2,168,710)	(3,466,255)	(4,552,272)	(4,851,485)	(4,057,146)	(2,145,212)	(334,159)	330,909	(199,009)	(1,553,833)	
2.	Ending True-Up Amount Before Interest ($)	(668,517)	(2,166,820)	(3,461,832)	(4,548,481)	(4,851,212)	(4,056,754)	(2,144,877)	(334,025)	330,909	(199,016)	(1,553,738)	(2,247,538)	
3.	Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	(453,621)	(2,835,642)	(5,630,542)	(8,014,736)	(9,403,484)	(8,908,239)	(6,202,023)	(2,479,237)	(3,250)	131,893	(1,752,747)	(3,801,371)	
4.	Average True-Up Amount ($)	(226,811)	(1,417,821)	(2,815,271)	(4,007,368)	(4,701,742)	(4,454,120)	(3,101,012)	(1,239,619)	(1,625)	65,947	(876,374)	(1,900,686)	
5.	Interest Rate - First Day of Reporting Business Month	1.59%	1.64%	1.56%	2.21%	0.06%	0.08%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	
6.	Interest Rate - First Day of Subsequent Business Month	1.64%	1.56%	2.21%	0.06%	0.08%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	
7.	Total Interest Rate (Lines 5 + 6)	3.23%	3.20%	3.77%	2.27%	0.14%	0.21%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	
8.	Average Interest Rate	1.615%	1.600%	1.885%	1.135%	0.070%	0.105%	0.130%	0.130%	0.130%	0.130%	0.130%	0.130%	
9.	Monthly Average Interest Rate (1/12 Of Line 8)	0.1346%	0.1333%	0.1571%	0.0946%	0.0058%	0.0088%	0.0108%	0.0108%	0.0108%	0.0108%	0.0108%	0.0108%	
10.	Interest Provision For the Month (Lines 4 X 9) ($)	(305)	(1,890)	(4,423)	(3,791)	(273)	(392)	(335)	(134)	0	7	(95)	(205)	(11,836)

SCHEDULE CCE-4

Gulf Power Company
2020 Capacity Contracts
ACTUAL FOR THE PERIOD JANUARY 2020 - JUNE 2020 / ESTIMATED FOR JULY 2020 - DECEMBER 2020

		(A)	(B)	(C)
		Term		Contract
	Contract/Counterparty	**Start**	**End (1)**	**Type**
1	**Southern Intercompany Interchange**	**5/1/2007**	**5 Yr Notice**	**SES Opco**
2	***PPAs***			
3	**Shell Energy N.A. (U.S.), LP**	**11/2/2009**	**5/31/2023**	**Firm**
4	***Other***			
5	**South Carolina PSA**	**9/1/2003**	**-**	**Other**
6	**Rainbow Energy Marketing Corporation**	**1/1/2020**	**2/29/2030**	**Other**

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Capacity Costs Description	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	TOTAL
7	Southern Intercompany Interchange	377	111	0	0	0	0	0	0	0	0	0	0	488
8	*PPAs*													
9	Shell Energy N.A. (U.S.), LP	[redacted]												
10	*Other*													
11	South Carolina PSA	[redacted]												
12	Rainbow Energy Marketing Corporation													
13	Total	7,101,412	7,095,801	7,075,227	7,075,227	7,075,227	7,075,227	7,148,521	7,148,521	7,148,521	7,148,521	7,148,521	7,148,521	85,389,241

	Capacity MW Description	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Projection	August Projection	September Projection	October Projection	November Projection	December Projection
14	Southern Intercompany Interchange	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	*PPAs*												
16	Shell Energy N.A. (U.S.), LP	[redacted]											
17	*Other*												
18	South Carolina PSA	[redacted]											
19	Rainbow Energy Marketing Corporation												

20 (1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 35
PARTY: GULF POWER COMPANY – DIRECT
DESCRIPTION: Richard L. Hume RLH-5

CONFIDENTIAL

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 37
PARTY: GULF POWER COMPANY – DIRECT
DESCRIPTION: Richard L. Hume RLH-7

GULF - 2021 PROJECTED SEPARATION FACTORS

CLAUSES

	SUMMARY
DEMAND	
Total Production/Transmission	0.972343
Non-Stratified Production	1.000000
Intermediate Strata Production	0.975922
Peaking Strata Production	0.760860
Distribution	0.981419
ENERGY	
Total Sales	0.974597
Non-Stratified Sales	1.000000
Intermediate Strata Sales	0.975922
Peaking Strata Sales	0.760860
GENERAL PLANT	
General Plant	0.969888

GULF POWER COMPANY
CALCULATION OF 2021 PROJ 12CPKW AT GENERATION BY RATE CLASS
TOTAL PRODUCTION & TRANSMISSION (NO ADJUSTMENTS)

RATE CLASS	(1) **2021 PROJ** Average 12CPKW @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** Average 12CPKW @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	1,077,395	1.00609343	1,083,960	
GS	64,217	1.00608241	64,607	
GSD/GSDT	390,857	1.00590017	393,163	
LP/LPT	111,599	0.98747379	110,201	
PX/PXT/RTP/CSA/SBS	240,698	0.96884429	233,199	
OSI/OSII	1,547	1.00619545	1,556	
OSIII	5,350	1.00617773	5,383	
JURISDICTIONAL	1,891,662		1,892,070	**97.23427%**
FPU (INT)	32,668	0.94895250	31,000	1.59310%
FPU (PEAK)	24,045	0.94895250	22,818	1.17262%
NON-JURISDICTIONAL	56,713		53,818	**2.76573%**
TERRITORIAL	1,948,375		1,945,887	100.00000%

GULF POWER COMPANY
CALCULATION OF 2021 PROJ 12CPKW AT GENERATION BY RATE CLASS
NON-STRATIFIED PRODUCTION

RATE CLASS	(1) **2021 PROJ** Average 12CPKW @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** Average 12CPKW @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	1,077,395	1.00609343	1,083,960	
GS	64,217	1.00608241	64,607	
GSD/GSDT	390,857	1.00590017	393,163	
LP/LPT	111,599	0.98747379	110,201	
PX/PXT/RTP/CSA/SBS	240,698	0.96884429	233,199	
OSI/OSII	1,547	1.00619545	1,556	
OSIII	5,350	1.00617773	5,383	
JURISDICTIONAL	1,891,662		1,892,070	**100.00000%**
FPU (INT)	0	0.94895250	0	0.00000%
FPU (PEAK)	0	0.94895250	0	0.00000%
NON-JURISDICTIONAL	0		0	**0.00000%**
TERRITORIAL	1,891,662		1,892,070	100.00000%

GULF POWER COMPANY
CALCULATION OF 2021 PROJ 12CPKW AT GENERATION BY RATE CLASS
INTERMEDIATE STRATA PRODUCTION

RATE CLASS	(1) **2021 PROJ** Average 12CPKW @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** Average 12CPKW @ GENER.	(3) ADJUSTED Average 12CPKW @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	1,077,395	1.00609343	1,083,960	1,083,960	
GS	64,217	1.00608241	64,607	64,607	
GSD/GSDT	390,857	1.00590017	393,163	393,163	
LP/LPT	111,599	0.98747379	110,201	110,201	
PX/PXT/RTP/CSA/SBS	240,698	0.96884429	233,199	233,199	
OSI/OSII	1,547	1.00619545	1,556	1,556	
OSIII	5,350	1.00617773	5,383	5,383	
JURISDICTIONAL	1,891,662		1,892,070	1,892,070	**97.59223%**
FPU (INT)	32,668	0.94895250	31,000	46,681	2.40777%
FPU (PEAK)	0	0.94895250	0	0	0.00000%
NON-JURISDICTIONAL	32,668		31,000	46,681	**2.40777%**
TERRITORIAL	1,924,330		1,923,070	1,938,750	100.00000%

GULF POWER COMPANY
CALCULATION OF 2021 PROJ 12CPKW AT GENERATION BY RATE CLASS
PEAKING STRATA PRODUCTION

RATE CLASS	(1) **2021 PROJ** Average 12CPKW @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** Average 12CPKW @ GENER.	(3) ADJUSTED Average 12CPKW @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	1,077,395	1.00609343	1,083,960	1,083,960	
GS	64,217	1.00608241	64,607	64,607	
GSD/GSDT	390,857	1.00590017	393,163	393,163	
LP/LPT	111,599	0.98747379	110,201	110,201	
PX/PXT/RTP/CSA/SBS	240,698	0.96884429	233,199	233,199	
OSI/OSII	1,547	1.00619545	1,556	1,556	
OSIII	5,350	1.00617773	5,383	5,383	
JURISDICTIONAL	1,891,662		1,892,070	1,892,070	**76.08600%**
FPU (INT)	0	0.94895250	0	0	0.00000%
FPU (PEAK)	24,045	0.94895250	22,818	594,682	23.91400%
NON-JURISDICTIONAL	24,045		22,818	594,682	**23.91400%**
TERRITORIAL	1,915,708		1,914,887	2,486,751	100.00000%

GULF POWER COMPANY
CALCULATION OF 2021 PROJ KWH SALES AT GENERATION BY RATE CLASS
TOTAL SALES (NO ADJUSTMENTS)

	(1)	(2)	(3)	(4)
RATE CLASS	**2021 PROJ** TOTAL KWH SALES @ METER	ENERGY LOSS EXPANSION FACTOR	**2021 PROJ** TOTAL KWH SALES @ GENER.	**2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	5,528,121,218	1.00559591	5,559,056,087	
GS	328,640,315	1.00559477	330,478,982	
GSD/GSDT	2,501,334,147	1.00544671	2,514,958,189	
LP/LPT	826,617,738	0.99210885	820,094,773	
PX/PXT/RTP/CSA/SBS	1,787,605,854	0.97666479	1,745,891,696	
OSI/OSII	100,786,002	1.00560119	101,350,524	
OSIII	46,997,061	1.00558881	47,259,719	
JURISDICTIONAL	11,120,102,335		11,119,089,969	**97.45969%**
FPU (INT)	207,769,383	0.96249530	199,977,054	1.75281%
FPU (PEAK)	93,345,665	0.96249530	89,844,763	0.78750%
NON-JURISDICTIONAL	301,115,048		289,821,817	**2.54031%**
TERRITORIAL	11,421,217,383		11,408,911,786	100.00000%

GULF POWER COMPANY
CALCULATION OF 2021 PROJ KWH SALES AT GENERATION BY RATE CLASS
NON-STRATIFIED SALES

RATE CLASS	(1) **2021 PROJ** TOTAL KWH SALES @ METER	(2) ENERGY LOSS EXPANSION FACTOR	(3) **2021 PROJ** TOTAL KWH SALES @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	5,528,121,218	1.00559591	5,559,056,087	
GS	328,640,315	1.00559477	330,478,982	
GSD/GSDT	2,501,334,147	1.00544671	2,514,958,189	
LP/LPT	826,617,738	0.99210885	820,094,773	
PX/PXT/RTP/CSA/SBS	1,787,605,854	0.97666479	1,745,891,696	
OSI/OSII	100,786,002	1.00560119	101,350,524	
OSIII	46,997,061	1.00558881	47,259,719	
JURISDICTIONAL	11,120,102,335		11,119,089,969	**100.00000%**
FPU (INT)	0	0.96249530	0	0.00000%
FPU (PEAK)	0	0.96249530	0	0.00000%
NON-JURISDICTIONAL	0		0	**0.00000%**
TERRITORIAL	11,120,102,335		11,119,089,969	100.00000%

GULF POWER COMPANY
CALCULATION OF 2021 PROJ KWH SALES AT GENERATION BY RATE CLASS
INTERMEDIATE STRATA SALES

RATE CLASS	(1) **2021 PROJ** TOTAL KWH SALES @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** TOTAL KWH SALES @ GENER.	(3) ADJUSTED TOTAL KWH SALES @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	5,528,121,218	1.00559591	5,559,056,087	5,559,056,087	
GS	328,640,315	1.00559477	330,478,982	330,478,982	
GSD/GSDT	2,501,334,147	1.00544671	2,514,958,189	2,514,958,189	
LP/LPT	826,617,738	0.99210885	820,094,773	820,094,773	
PX/PXT/RTP/CSA/SBS	1,787,605,854	0.97666479	1,745,891,696	1,745,891,696	
OSI/OSII	100,786,002	1.00560119	101,350,524	101,350,524	
OSIII	46,997,061	1.00558881	47,259,719	47,259,719	
JURISDICTIONAL	11,120,102,335		11,119,089,969	11,119,089,969	**97.59223%**
FPU (INT)	207,769,383	0.96249530	199,977,054	274,326,931	2.40777%
FPU (PEAK)	0	0.96249530	0	0	0.00000%
NON-JURISDICTIONAL	207,769,383		199,977,054	274,326,931	**2.40777%**
TERRITORIAL	11,327,871,718		11,319,067,023	11,393,416,900	100.00000%

0.97592233

GULF POWER COMPANY
CALCULATION OF 2021 PROJ 12CPKW AT GENERATION BY RATE CLASS
PEAKING STRATA PRODUCTION

RATE CLASS	(1) **2021 PROJ** TOTAL KWH SALES @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** TOTAL KWH SALES @ GENER.	(3) ADJUSTED TOTAL KWH SALES @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	5,528,121,218	1.00559591	5,559,056,087	5,559,056,087	
GS	328,640,315	1.00559477	330,478,982	330,478,982	
GSD/GSDT	2,501,334,147	1.00544671	2,514,958,189	2,514,958,189	
LP/LPT	826,617,738	0.99210885	820,094,773	820,094,773	
PX/PXT/RTP/CSA/SBS	1,787,605,854	0.97666479	1,745,891,696	1,745,891,696	
OSI/OSII	100,786,002	1.00560119	101,350,524	101,350,524	
OSIII	46,997,061	1.00558881	47,259,719	47,259,719	
JURISDICTIONAL	11,120,102,335		11,119,089,969	11,119,089,969	**76.08600%**
FPU (INT)	0	0.96249530	0	0	0.00000%
FPU (PEAK)	93,345,665	0.96249530	89,844,763	3,494,754,515	0.80155%
NON-JURISDICTIONAL	93,345,665		89,844,763	3,494,754,515	**23.91400%**
TERRITORIAL	11,213,448,000		11,208,934,732	14,613,844,484	100.00000%

GULF POWER COMPANY
CALCULATION OF 2021 PROJ DISTRIBUTION AND GENERAL PLANT SEPARTION FACTORS
DISTRIBUTION AND GENERAL PLANT

Description	Total Total Adjusted Utility	Unit Power Sales	($000s) Total Adjusted Utility Net Of UPS	Jurisdictional Amount	Jurisdictional Separation Factor
DISTRIBUTION					
Land and Land Rights	3,137	0	3,137	3,063	0.9764106
Structures and Improvements	25,825	0	25,825	25,226	0.9768054
Station Equipment	214,784	0	214,784	210,928	0.9820471
DISTRIBUTION			243,746	239,217	0.9814192
GENERAL PLANT	205,892	1,339	204,553	201,302	0.9841068

EXHIBIT TO THE TESTIMONY OF

J. A. VAN NORMAN

IN FPSC DOCKET 20200001-EI

I. CORRECTIONS TO REPORTED DATA FOR THE JANUARY 2019 - DECEMBER 2019 PERIOD

Additions and Corrections to Outages Previously Reported
for the January 2019 - December 2019 Period

Date	Unit	Change	Outage Type	Hours	MW	Description
January filing	Crist 7	PFOH - NC	D1 - NC	5.6	43.0	Pulverizer derate changed to non-curtailing event LRpf increased. EAF 85% to 83.8%
March filing*	Crist 7	LRpf & LRpm				EAF changed 99.1% to 98.9%
April filing	Daniel 1	PFOH -PMOH		10.9	130.0	Planned derate changed from PFOH to PMOH
April filing	Daniel 2	PFOH		8.8	48.9	Typo on original PFOH and LRpf at 0.0
April filing	Daniel 2	MOH & RSH				Outage time changed increased MOH and RSH decreased EAF 94.2% to 93.4%
April filing*	Crist 7	LRpf				EAF changed 83.7% to 83.1%
May filing*	Crist 7	LRpf & LRpm				EAF changed 96.0% to 95.3%
June filing	Crist 4	LRpf & LRpm				EAF changed 92.1% to 91.81%
June filing*	Crist 7	LRpf				EAF changed 99.4% to 99.1%
July filing*	Crist 7	LR pf	D1	411.8	120.0	LRpf changed from 195 to 120 EAF changed 73.6% to 82.55%
Sept filing	Crist 6	RSH				Added 44.6 RSH no change EAF

* An error was made in reporting the reduction due to using gross generation instead of net generation.

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
for January 2019 - December 2019

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Smith 3A	1	3/21/2019 - 5/25/2019	1584.0	3/21/2019 - 5/25/2019	1504.2
Smith 3B	1	5/15/2019 - 7/20/2019	1608.0	5/15/2019 - 7/18/2019	1351.4
Smith 3ST	1	5/15/2019 - 5/25/2019	264.0	05/16/19 - 05/26/19	201.7
Scherer 3	1	2/2/2019 - 4/21/2019	1894.0	2/2/2019 - 4/10/2019	1616.0
Daniel 2	1	10/14/2019 - 12/16/2019	1536.0	10/14/2019 - 12/16/2019	1536.1
Crist 6	1	11/10/2019 - 12/20/2019	984.0	11/10/2019 - 12/20/2019	956.6

* Planned outage hours in the January 2019 - December 2019 period only.

Notes: 1. The outage proceeded as scheduled.

2. The outage was added subsequent to the target filing.

3. The outage date was changed subsequent to the target filing.

4. The outage date proceeded as scheduled and extended.

Calculation of Actual Equivalent Availability
for January 2019 - December 2019
Based on Target Planned Outage Hours
Scherer 3

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EFOH	0.0	0.0	0.0	0.0	0.0	10.1	
	0.0	3.7	3.0	0.0	0.0	0.0	16.8
MOH	0.0	12.0	0.0	0.0	0.0	36.9	
	0.0	0.0	0.0	0.0	0.0	58.0	106.9
EMOH	0.0	0.0	0.0	4.3	0.0	5.8	
	0.0	0.0	0.0	0.0	0.0	0.0	10.1
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
POH	0.0	648.0	743.0	225.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1616.0
RSH	0.0	12.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	215.1	523.3	750.4

1. $$EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(0.0 + 16.8 + 106.9 + 10.1)}{(8760.0 - 1616.0 - 750.4)}$$

EUOR = 0.0209

2. $$EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1560.0

Target RSH* = 699.0

$$EA = \left[1 - \frac{(1560.0 + 0.0209\ (8760.0 - 1560.0 - 699.0))}{8760.0} \right] \times 100 = 80.6\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2019 - December 2019
Based on Target Planned Outage Hours
Crist 7

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	1.1	0.0	0.0	2.2	1.3	0.0	4.6
EFOH	0.0	0.0	0.0	4.1	0.0	0.0	
	0.0	0.0	0.0	11.1	0.0	0.2	15.4
MOH	104.1	0.0	0.0	312.0	0.0	51.6	
	39.4	143.4	108.9	111.6	114.3	0.0	985.3
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	24.0	448.0	0.0	111.1	0.0	0.0	
	0.0	0.0	0.0	0.0	244.1	13.0	840.2

1. $$EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(4.6 + 15.4 + 985.3 + 0.0)}{(8760.0 - 0.0 - 840.2)}$$

EUOR = 0.1269

2. $$EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 1964.0

$$EA = \left[1 - \frac{(0.0 + 0.1269\ (8760.0 - 0.0 - 1964.0))}{8760.0} \right] \times 100 = 90.2\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2019 - December 2019
Based on Target Planned Outage Hours
Daniel 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	39.1	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	2.8	0.0	41.8
EFOH	0.7	0.0	3.1	0.0	0.0	1.1	
	0.0	1.1	0.0	0.0	0.0	0.0	6.0
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	192.0	0.0	192.0
EMOH	45.3	9.0	127.8	121.2	27.7	4.2	
	14.9	0.0	7.0	33.6	13.7	0.0	404.4
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	457.8	626.6	471.5	0.0	148.3	220.3	
	193.1	323.1	26.7	275.5	373.7	744.0	3860.5

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(41.8 + 6.0 + 192.0 + 404.4)}{(8760.0 - 0.0 - 3860.5)}$$

EUOR = 0.1315

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 216.0

Target RSH* = 4459.0

$$EA = \left[1 - \frac{(216.0 + 0.1315\ (8760.0 - 216.0 - 4459.0))}{8760.0} \right] \times 100 = 91.4\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2019 - December 2019
Based on Target Planned Outage Hours
Daniel 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	23.5	2.1	0.0	4.9	
	0.0	0.0	6.8	0.0	0.0	20.1	57.4
EFOH	0.0	0.0	2.4	5.5	0.6	3.5	
	0.0	0.4	5.8	0.0	0.0	0.0	18.2
MOH	0.0	50.0	87.1	0.0	40.9	59.5	
	0.0	0.0	0.0	48.3	0.0	0.0	285.8
EMOH	106.8	4.9	165.6	129.3	0.0	48.5	
	78.7	76.3	22.6	12.4	0.0	9.8	654.9
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	432.0	721.0	383.1	1536.1
RSH	96.5	600.5	156.8	0.0	273.6	0.0	
	0.0	0.0	0.0	0.0	0.0	204.2	1331.5

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(57.4 + 18.2 + 285.8 + 654.9)}{(8760.0 - 1536.1 - 1331.5)}$$

EUOR = 0.1725

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 888.0

Target RSH* = 3612.0

$$EA = \left[1 - \frac{(888.0 + 0.1725\ (8760.0 - 888.0 - 3612.0))}{8760.0} \right] \times 100 = 81.5\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2019 - December 2019
Based on Target Planned Outage Hours
Smith 3

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	3.2	0.0	0.0	0.0	3.2
EFOH	0.0	0.0	0.0	0.2	0.0	0.0	
	1.5	0.0	0.0	0.0	0.0	0.0	1.7
MOH	0.0	0.0	0.0	0.0	0.0	18.6	
	16.8	0.0	0.0	0.0	0.0	0.0	35.4
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	2.2	2.2	0.0	0.0	0.0	4.4
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	201.7	0.0	
	0.0	0.0	0.0	0.0	294.9	0.0	496.6
RSH	0.0	0.0	0.0	0.0	0.0	17.6	
	0.0	0.0	0.0	0.0	0.0	0.0	17.6

1. $$EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(3.2 + 1.7 + 35.4 + 4.4)}{(8760.0 - 496.6 - 17.6)}$$

EUOR = 0.0054

2. $$EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 433.0

Target RSH* = 826.0

$$EA = \left[1 - \frac{(433.0 + 0.0054\ (8760.0 - 433.0 - 826.0))}{8760.0} \right] \times 100 = 94.6\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
for January 2019 - December 2019

(1) Unit	(2) Equivalent Availability Target*	(3) Actual Equivalent Availability Adjusted to Target Planned Outage Basis**	(4) Minimum or Maximum Attainable Equivalent Availability*	(5) Availability Points***
Scherer 3	79.5	80.6	80.4	10.00
Crist 7	90.2	90.2	85.8	0.00
Daniel 1	93.5	91.4	93.5	0.00
Daniel 2	86.5	81.5	86.5	0.00
Smith 3	93.6	94.6	94.0	10.00

* As appropriate from page 5, Schedule 3 of Exhibit to C. L. Nicholson's August 24, 2018 GPIF Testimony in Docket 20180001-EI.

** Refer to pages 3 through 7 of this Schedule for calculations.

*** If (3) > (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times 10$$

If (3) < (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times -10$$

Summary of Equivalent Availability Symbols

EA - Equivalent Availability
POH - Planned Outage Hours
EUOR - Equivalent Unplanned Outage Rate
PH - Period Hours
FOH - Forced Outage Hours
EFOH - Equivalent Forced Outage Hours
MOH - Maintenance Outage Hours
EMOH - Equivalent Maintenance Outage Hours
RSH - Reserve Shutdown Hours

III. CALCULATION OF GPIF UNIT HEAT RATE POINTS

Calculation of Average Net Operating Heat Rate Points
for January 2019 - December 2019

Scherer 3

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	380252.0	0.0	0.0	275974.0	484616.0	373618.0	
	493244.0	379530.0	419204.0	356106.0	242564.0	69104.0	3474212.0
BTU/Lb*	8306.5	0.0	0.0	8322.0	8352.0	8336.6	
	8299.0	8396.0	8489.0	8477.0	8522.0	8501.0	8384.4
Coal, MMBTU	3158581.4	0.0	0.0	2296655.6	4047512.8	3114711.8	
	4093432.0	3186533.9	3558622.8	3018710.6	2067130.4	587453.1	29129344.4
Oil, MMBTU	391.0	0.0	0.0	10034.4	0.7	3032.6	
	0.0	0.3	75.4	34.8	473.1	7074.2	21116.5
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	0.0	-5373.0	0.0	-5373.0	
	0.0	0.0	0.0	0.0	0.0	-5373.0	-16119.0
Total Fuel	3158972.4	0.0	0.0	2301317.0	4047513.5	3112371.4	
Consumption, MMBTU	4093432.0	3186534.2	3558698.2	3018745.4	2067603.5	589154.3	29134341.9
Net MWH	286310	0	0	204610	375400	281035	
Generation***	377350	284089	327588	270936	195149	45705	2648172
Average Net	11033	---	---	11247	10782	11075	
Operating Heat Rate	10848	11217	10863	11142	10595	12890	11002

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2019 - December 2019

Crist 7

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	171013.5	60885.8	211703.4	82350.4	207907.3	180604.3	
	206094.9	168716.9	181408.0	161374.0	108190.4	197296.0	1937545.0
BTU/Lb*	11160.1	11423.0	11300.3	10862.9	11255.0	11194.0	
	11088.0	11394.0	11137.0	11559.0	11302.0	11624.0	11283.3
Coal, MMBTU	1908533.6	695501.6	2392302.0	894567.4	2339997.3	2021685.0	
	2285180.0	1922360.4	2020340.9	1865322.1	1222768.2	2293368.7	21861927.2
Oil, MMBTU	2767.1	475.5	637.0	941.6	2866.3	4334.1	
	1938.1	1619.4	2054.5	3191.6	4101.1	1386.7	26313.0
Gas, MMBTU	5309.8	4098.6	0.0	11510.9	15571.7	9108.6	
	4776.3	3828.2	3150.4	6895.6	13630.7	115384.0	193264.7
Startup, MMBTU **	-2256.0	-2256.0	0.0	-2256.0	0.0	0.0	
	-2256.0	-2256.0	-2256.0	-2256.0	-4512.0	0.0	-20304.0
Total Fuel Consumption, MMBTU	1914354.5	697819.7	2392939.0	904763.9	2358435.3	2035127.7	
	2289638.4	1925552.0	2023289.8	1873153.3	1235988.0	2410139.4	22061201.0
Net MWH Generation***	181840	66432	219428	84439	221223	185647	
	211307	182381	199805	181152	118793	221905	2074352
Average Net Operating Heat Rate	10528	10504	10905	10715	10661	10962	
	10836	10558	10126	10340	10405	10861	10635

* Weighted average of daily as-burned BTU/Lb values.

** Based on number of unit starts after unit off-line 24 hours or more.

*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2019 - December 2019

Daniel 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	61566.0	10294.0	60338.0	184318.0	159234.0	126070.0	
	145516.0	110494.0	189234.0	121144.0	33442.0	0.0	1201650.0
BTU/Lb*	9207.1	8908.0	9247.0	8685.0	9155.0	9101.0	
	9064.0	8939.0	9188.0	8946.0	8806.0	0.0	9025.9
Coal, MMBTU	566844.5	91699.0	557945.5	1600801.8	1457787.3	1147363.1	
	1318957.0	987705.9	1738682.0	1083754.2	294490.3	0.0	10846030.6
Oil, MMBTU	5181.1	865.9	13214.7	4108.6	4622.7	3897.3	
	652.2	4894.7	4030.9	3554.2	4775.6	0.0	49797.9
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	-2388.7	0.0	-4777.4	0.0	-2388.7	-2388.7	
	0.0	-2388.7	-2388.7	-2388.7	-2388.7	0.0	-21498.3
Total Fuel Consumption, MMBTU	569636.9	92564.9	566382.8	1604910.4	1460021.3	1148871.7	
	1319609.2	990211.9	1740324.2	1084919.7	296877.2	0.0	10874330.2
Net MWH Generation***	47557	7671	45643	143325	131978	102545	
	117733	87521	155349	96688	28242	0	964252
Average Net Operating Heat Rate	11978	12067	12409	11198	11063	11204	
	11208	11314	11203	11221	10512	---	11277

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2019 - December 2019

Daniel 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	134400.0	3650.0	110042.0	185718.0	95222.0	142696.0	
	178488.0	197330.0	192342.0	67860.0	0.0	31960.0	1339708.0
BTU/Lb*	8777.0	9103.0	8727.0	8745.8	11024.5	9841.0	
	9783.0	9110.0	9651.0	9051.0	0.0	8760.0	9364.6
Coal, MMBTU	1179628.8	33226.0	960336.5	1624247.2	1049772.0	1404271.3	
	1746148.1	1797676.3	1856292.6	614200.9	0.0	279969.6	12545769.3
Oil, MMBTU	7256.7	483.6	11877.2	20162.2	7877.6	10679.7	
	6392.2	2781.3	3784.1	364.5	0.0	11347.3	83006.4
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	-2388.7	0.0	-4777.4	0.0	-2388.7	-2388.7	
	0.0	0.0	0.0	0.0	0.0	-2388.7	-14332.2
Total Fuel	1184496.8	33709.6	967436.3	1644409.4	1055260.9	1412562.3	
Consumption, MMBTU	1752540.3	1800457.6	1860076.7	614565.4	0.0	288928.2	12614443.5
Net MWH	98754	2830	88876	145415	104509	125122	
Generation***	156379	159555	172284	57076	0	21549	1132349
Average Net	11994	11912	10885	11308	10097	11289	
Operating Heat Rate	11207	11284	10797	10767	---	13408	11140

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2019 - December 2019

Smith 3

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BTU/Lb*	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas, MMBTU	2698322.5	2236888.6	2591016.7	2566409.5	1615364.3	2484766.3	
	2654276.5	2720196.5	2627729.5	778079.4	2054343.3	2257053.9	27284447.0
Startup, MMBTU **	0.0	0.0	0.0	0.0	-1200.0	0.0	
	0.0	0.0	0.0	0.0	-1200.0	0.0	-2400.0
Total Fuel	2698322.5	2236888.6	2591016.7	2566409.5	1614164.3	2484766.3	
Consumption, MMBTU	2654276.5	2720196.5	2627729.5	778079.4	2053143.3	2257053.9	27282047.0
Net MWH	362382	355633	322298	184989	139755	196972	
Generation***	333811	454677	440950	448924	244166	439216	3931773
Average Net	7446	6290	8039	13873	11550	12615	
Operating Heat Rate	7951	5983	5853	1733	8409	5139	6939

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate
for January 2019 - December 2019
Adjusted to Target Basis Using Heat Rate
Equations Filed August 24, 2018

Scherer 3

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	11308	0	10778	10893	10804	10598	
		10376	10399	10635	10512	10764	10753	
2.	Target Heat Rate at Actual Conditions**	10999	0	10778	11093	10862	11175	
		10638	11011	11078	11084	10996	11554	
3.	Adjustment to Actual Heat Rate (1-2)	309	0	0	-200	-58	-577	
		-262	-612	-443	-572	-232	-801	
4.	Actual Heat Rate (Page 2 of Sched. 3)	11033	0	0	11247	10782	11075	
		10848	11217	10863	11142	10595	12888	
5.	Adjusted Actual Heat Rate (4+3)	11342	0	0	11047	10724	10498	
		10586	10605	10420	10570	10363	12087	
6.	Net MWH Generation	286310	0	0	204610	375400	281035	
		377350	284089	327588	270936	195149	45705	
7.	Adjusted Actual Heat Rate for January 2019 - December 2019 $=(\Sigma(5*6)/\Sigma 6)$							10703

* From pages 17 & 18, Schedule 3 of Exhibit to C. L. Nicholson's August 24, 2018 GPIF Testimony in Docket 20180001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2019 - December 2019
Adjusted to Target Basis Using Heat Rate
Equations Filed August 24, 2018

Crist 7

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10822	10533	0	0	10666	10486	
		10440	10464	10514	10741	10399	10995	
2.	Target Heat Rate	10755	10481	10397	10813	10744	10850	
	at Actual Conditions**	10728	10712	10606	10796	10121	10712	
3.	Adjustment to Actual	67	52	188	-228	-78	-364	
	Heat Rate (1-2)	-288	-248	-92	-55	278	283	
4.	Actual Heat Rate	10528	10504	10905	10715	10661	10962	
	(Page 3 of Sched. 3)	10836	10558	10126	10340	10404	10861	
5.	Adjusted Actual	10595	10556	11093	10487	10583	10598	
	Heat Rate (4+3)	10548	10310	10034	10285	10682	11144	
6.	Net MWH Generation	181840	66432	219428	84439	221223	185647	
		211307	182381	199805	181152	118793	221905	
7.	Adjusted Actual Heat Rate for January 2019 - December 2019 $=(\Sigma(5*6)/\Sigma 6)$							10594

* From pages 19 & 20, Schedule 3 of Exhibit to C. L. Nicholson's August 24, 2018 GPIF Testimony in Docket 20180001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 13 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2019 - December 2019
Adjusted to Target Basis Using Heat Rate
Equations Filed August 24, 2018

Daniel 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	12070	11384	12488	13065	12399	12060	
		11681	11533	12327	11866	11979	12492	
2.	Target Heat Rate	12014	11115	11602	11968	11345	11505	
	at Actual Conditions**	11419	11477	11241	11143	11307	12492	
3.	Adjustment to Actual	56	269	886	1097	1054	555	
	Heat Rate (1-2)	262	56	1086	723	672	0	
4.	Actual Heat Rate	11977	12066	12406	11197	11062	11203	
	(Page 4 of Sched. 3)	11208	11313	11202	11220	10509	0	
5.	Adjusted Actual	12033	12335	13292	12294	12116	11758	
	Heat Rate (4+3)	11470	11369	12288	11943	11181	0	
6.	Net MWH Generation	47557	7671	45643	143325	131978	102545	
		117733	87521	155349	96688	28242	0	
7.	Adjusted Actual Heat Rate for January 2019 - December 2019 $=(\Sigma(5*6)/\Sigma 6)$							11994

* From pages 21 & 22 , Schedule 3 of Exhibit to C. L. Nicholson's August 24, 2018 GPIF Testimony in Docket 20180001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 13 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2019 - December 2019
Adjusted to Target Basis Using Heat Rate
Equations Filed August 24, 2018

Daniel 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	12855	11533	11773	0	0	11698	
		11408	11257	12078	0	0	0	
2.	Target Heat Rate	12686	11927	11116	11958	11088	11710	
	at Actual Conditions**	11444	11392	11104	11178	0	12318	
3.	Adjustment to Actual	169	-394	657	-285	585	-12	
	Heat Rate (1-2)	-36	-135	974	495	0	-645	
4.	Actual Heat Rate	11994	11910	10884	11307	10096	11288	
	(Page 5 of Sched. 3)	11206	11284	10796	10767	0	13399	
5.	Adjusted Actual	12163	11516	11541	11022	10681	11276	
	Heat Rate (4+3)	11170	11149	11770	11262	0	12754	
6.	Net MWH Generation	98754	2830	88876	145415	104509	125122	
		156379	159555	172284	57076	0	21549	
7.	Adjusted Actual Heat Rate for January 2019 - December 2019 $=(\Sigma(5*6)/\Sigma 6)$							11357

* From pages 23 & 24, Schedule 3 of Exhibit to C. L. Nicholson's August 24, 2018 GPIF Testimony in Docket 20180001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 13 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2019 - December 2019
Adjusted to Target Basis Using Heat Rate
Equations Filed August 24, 2018

Smith 3

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	6892	6888	6883	6874	6874	6897	
		6992	6902	6901	6725	6875	6885	
2.	Target Heat Rate at Actual Conditions**	6983	6930	7065	7580	7576	7443	
		7137	6848	6835	6714	6883	6867	
3.	Adjustment to Actual Heat Rate (1-2)	-91	-42	-182	-706	-702	-546	
		-145	54	66	11	-8	18	
4.	Actual Heat Rate*** (Page 6 of Sched. 3)	6970	6947	6983	6995	7148	7047	
		7112	7058	6812	7043	6962	6937	
5.	Adjusted Actual Heat Rate (4+3)	6879	6905	6801	6289	6446	6501	
		6967	7112	6878	7054	6954	6955	
6.	Net MWH Generation	362382	355633	322298	184989	139755	196972	
		333811	454677	448950	448924	244166	439216	
7.	Adjusted Actual Heat Rate for January 2019 - December 2019 $=(\Sigma(5*6)/\Sigma 6)$							6880

* From pages 25 & 26, Schedule 3 of Exhibit to C. L. Nicholson's August 24, 2018 GPIF Testimony in Docket 20180001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 13 of this Schedule.

Actual Values of
Target Heat Rate Equation Parameters
for January 2019 - December 2019

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Scherer 3							
	AKW * 10^{+3}	384.8	0.0	0.0	413.3	504.6	411.4
		507.2	381.8	455.0	364.2	385.7	280.8
	LSRF * 10^{+6}	386354.0	144270.6	157814.7	244953.9	371341.3	371426.8
		424885.7	427663.1	542923.0	457944.9	480547.6	281821.6
Crist 7							
	AKW * 10^{+3}	295.2	296.5	295.3	284.4	297.3	277.8
		300.4	303.7	327.0	287.4	328.8	303.6
	LSRF * 10^{+6}	166143.2	119479.8	0.0	0.0	105423.2	114968.7
		133168.1	128197.3	162551.1	148506.2	141149.9	106997.0
Daniel 1							
	AKW * 10^{+3}	166.2	168.9	196.4	199.1	221.5	205.2
		213.7	207.9	224.1	206.4	185.1	0.0
	LSRF * 10^{+6}	37935.7	30084.3	0.0	43395.0	40674.8	44571.7
		25969.6	29970.8	46225.1	57977.9	43516.3	43639.1
Daniel 2							
	AKW * 10^{+3}	152.5	131.5	186.9	202.5	243.3	190.9
		210.2	214.5	241.6	216.4	0.0	157.7
	LSRF * 10^{+6}	59050.5	35431.5	63535.8	33429.0	54712.2	52414.2
		30392.2	37277.5	47906.8	50187.9	44651.9	34581.4
Smith 3							
	AKW * 10^{+3}	487.1	529.2	433.8	256.9	257.7	288.1
		459.0	611.1	626.3	603.4	573.0	590.3
	LSRF * 10^{+6}	283941.8	245180.1	274783.0	288168.6	229496.9	251178.0
		280326.6	271400.8	277560.0	295736.8	188065.0	220574.4

Target Heat Rate Equations

Scherer 3 ANOHR = 10^6 / AKW * [576.13 + 81.47 * APR + 110.08 * MAY + 112.05 * JUN + 141.10 * SEP]
+ 9,502

Crist 7 ANOHR = 10^6 / AKW * [452.14 - 79.14 * FEB - 105.38 * MAR - 156.80 * NOV]
+ 9,223

Daniel 1 ANOHR = 10^6 / AKW * [444.94 - 144.67 * FEB + 78.90 * APR - 18.22 * SEP - 72.06 * OCT - 80.33 * NOV]
+ 9,337

Daniel 2 ANOHR = 10^6 / AKW * [551.33 + 37.93 * JAN - 142.94 * FEB - 122.48 * MAR + 83.72 * APR - 41.35 * OCT - 105.10 * NOV]
+ 8,822

Smith 3 ANOHR = 10^6 / AKW * [324.40 + 51.80 * JUL - 85.12 * OCT]
+ 6,317

Where:

Where:	ANOHR	Average Net Operating Heat Rate, BTU/KWH
	AKW	Average Kilowatt Load, KW
	LSRF	Load Square Range Factor, KW^2
	JAN	January, 0 if not January, 1 if January
	FEB	February, 0 if not February, 1 if February
	MAR	March, 0 if not March, 1 if March
	APR	April, 0 if not April, 1 if April
	MAY	May, 0 if not May, 1 if May
	JUN	June, 0 if not June, 1 if June
	JUL	July, 0 if not July, 1 if July
	AUG	August, 0 if not August, 1 if August
	SEP	September, 0 if not September, 1 if September
	OCT	October, 0 if not October, 1 if October
	NOV	November, 0 if not November, 1 if November

Calculation of Heat Rate Points
for January 2019 - December 2019

(1) Unit	(2) Actual Average Net Operating Heat Rate Target*	(3) Net Operating Heat Rate Adjusted to Target Basis**	(4) Minimum Attainable Heat Rate*	(5) Heat Rate Points***
Scherer 3	10,617	10,703	10,298	-0.45
Crist 7	10,585	10,594	10,267	0.00
Daniel 1	11,976	11,994	11,617	0.00
Daniel 2	11,673	11,357	11,323	8.76
Smith 3	6,882	6,880	6,676	0.00

* From page 5, Schedule 3 of Exhibit to C. L. Nicholson's August 24, 2018 GPIF Testimony in Docket 20180001-EI.

** Refer to pages 7 through 11 of this Schedule for calculation.

*** If [(2) - 75] <= (3) <= [(2) + 75] then points = 0

If [(2) - (3) - 75] > 0 then points = $\frac{(2) - (3) - 75}{(2) - (4) - 75} * 10$

If [(2) - (3) + 75] < 0 then points = $\frac{(2) - (3) + 75}{(2) - (4) - 75} * 10$

IV. CALCULATION OF COMPANY GPIF POINTS AND REWARD/PENALTY

Calculation of Heat Rate Points

GPIF Points and Reward or Penalty

for January 2019 - December 2019

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Scherer 3	10.00	0.002	-0.45	0.250
Crist 7	0.00	0.002	0.00	0.116
Daniel 1	0.00	0.000	0.00	0.005
Daniel 2	0.00	0.000	8.76	0.008
Smith 3	10.00	0.012	0.00	0.606

Company GPIF Points =	+ 10.00	*	0.002	-	0.45	*	0.250
	+ 0.00	*	0.002	+	0.00	*	0.116
	+ 0.00	*	0.000	+	0.00	*	0.005
	+ 0.00	*	0.000	+	8.76	*	0.008
	+ 10.00	*	0.012	+	0.00	*	0.606

= 0.10

Company reward/penalty = 0.10 points * $622319 per point

= $62,232

* From page 5, Schedule 3 of Exhibit to C. L. Nicholson's August 24, 2018 GPIF Testimony in Docket 20180001-EI.

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE JANUARY 2019 - DECEMBER 2019 PERIOD

CONTENTS	SCHEDULE 5 PAGE

Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: January 2019 - December 2019

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	4827	2414
+ 9	4344	2172
+ 8	3862	1931
+ 7	3379	1689
+ 6	2896	1448
+ 5	2414	1207
+ 4	1931	965
+ 3	1448	724
+ 2	965	483
+ 1	483	241
0	0	0
- 1	-482	-241
- 2	-963	-482
- 3	-1445	-722
- 4	-1926	-963
- 5	-2408	-1204
- 6	-2890	-1445
- 7	-3371	-1686
- 8	-3853	-1926
- 9	-4334	-2167
- 10	-4816	-2408
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Issued by: Gulf Power Company

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Actual

Gulf Power Company

Period of: January 2019 - December 2019

Line 1	Beginning of Period Balance of Common Equity	$1,920,031,100
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '19	$1,940,430,245
Line 3	Month of Feb '19	$1,946,466,972
Line 4	Month of Mar '19	$1,896,129,395
Line 5	Month of Apr '19	$1,909,911,059
Line 6	Month of May '19	$2,022,690,268
Line 7	Month of Jun '19	$2,037,671,895
Line 8	Month of Jul '19	$2,062,598,903
Line 9	Month of Aug '19	$2,088,585,382
Line 10	Month of Sep '19	$1,764,071,305
Line 11	Month of Oct '19	$1,705,625,843
Line 12	Month of Nov '19	$1,712,315,711
Line 13	Month of Dec '19	$1,715,531,598
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$1,901,696,898
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	74.3727%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$6,392,454
Line 18	Jurisdictional Sales (KWH)	11,078,868,686
Line 19	Total Territorial Sales (KWH)	11,380,206,717
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	97.3521%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$6,223,187
Line 22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF point level from sheet 7.383.9)	$2,413,500
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF Pt. level) (The lesser of Line 21 and Line 22)	$2,413,500

Issued by: Gulf Power Company

Calculation of System Actual GPIF Points

Gulf Power Company

Period of: January 2019 - December 2019

Plant & Unit	Performance Indicator (EAF or ANOHR)	Weighting Factor	Unit Points	Weighted Unit Points
Scherer 3	EAF3	0.2%	10.00	0.023
Scherer 3	ANOHR3	25.0%	-0.45	-0.112
Crist 7	EAF4	0.2%	0.00	0.000
Crist 7	ANOHR4	11.6%	0.00	0.000
Daniel 1	EAF5	0.0%	0.00	0.000
Daniel 1	ANOHR5	0.5%	0.00	0.000
Daniel 2	EAF6	0.0%	0.00	0.000
Daniel 2	ANOHR6	0.8%	8.76	0.067
Smith 3	EAF7	1.2%	10.00	0.118
Smith 3	ANOHR7	60.6%	0.00	0.000
Gulf Power GPIF Total		100.0%		0.10

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2019 - December 2019

Scherer 3

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	11	80.40	+ 10	1,205	10,298
+ 9	10	80.31	+ 9	1,085	10,322
+ 8	9	80.22	+ 8	964	10,347
+ 7	8	80.13	+ 7	844	10,371
+ 6	7	80.04	+ 6	723	10,396
+ 5	6	79.95	+ 5	603	10,420
+ 4	4	79.86	+ 4	482	10,444
+ 3	3	79.77	+ 3	362	10,469
+ 2	2	79.68	+ 2	241	10,493
+ 1	1	79.59	+ 1	121	10,518
				0	10,542
0	0	79.50	0	0	10,617
				0	10,692
- 1	(1)	79.39	- 1	(121)	10,716
- 2	(3)	79.28	- 2	(241)	10,741
- 3	(4)	79.17	- 3	(362)	10,765
- 4	(5)	79.06	- 4	(482)	10,790
- 5	(7)	78.95	- 5	(603)	10,814
- 6	(8)	78.84	- 6	(723)	10,838
- 7	(9)	78.73	- 7	(844)	10,863
- 8	(10)	78.62	- 8	(964)	10,887
- 9	(12)	78.51	- 9	(1,085)	10,912
- 10	(13)	78.40	- 10	(1,205)	10,936

Weighting Factor: 0.002 Weighting Factor: 0.250

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2019 - December 2019

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	10	93.20	+ 10	559	10,267
+ 9	9	92.90	+ 9	503	10,291
+ 8	8	92.60	+ 8	447	10,316
+ 7	7	92.30	+ 7	391	10,340
+ 6	6	92.00	+ 6	335	10,364
+ 5	5	91.70	+ 5	280	10,389
+ 4	4	91.40	+ 4	224	10,413
+ 3	3	91.10	+ 3	168	10,437
+ 2	2	90.80	+ 2	112	10,461
+ 1	1	90.50	+ 1	56	10,486
				0	10,510
0	0	90.20	0	0	10,585
				0	10,660
- 1	(2)	89.76	- 1	(56)	10,684
- 2	(4)	89.32	- 2	(112)	10,709
- 3	(6)	88.88	- 3	(168)	10,733
- 4	(8)	88.44	- 4	(224)	10,757
- 5	(10)	88.00	- 5	(280)	10,782
- 6	(12)	87.56	- 6	(335)	10,806
- 7	(14)	87.12	- 7	(391)	10,830
- 8	(16)	86.68	- 8	(447)	10,854
- 9	(18)	86.24	- 9	(503)	10,879
- 10	(20)	85.80	- 10	(559)	10,903

Weighting Factor: 0.002 Weighting Factor: 0.116

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2019 - December 2019

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	0	95.60	+ 10	25	11,617
+ 9	0	95.39	+ 9	23	11,645
+ 8	0	95.18	+ 8	20	11,674
+ 7	0	94.97	+ 7	18	11,702
+ 6	0	94.76	+ 6	15	11,731
+ 5	0	94.55	+ 5	13	11,759
+ 4	0	94.34	+ 4	10	11,787
+ 3	0	94.13	+ 3	8	11,816
+ 2	0	93.92	+ 2	5	11,844
+ 1	0	93.71	+ 1	3	11,873
				0	11,901
0	0	93.50	0	0	11,976
				0	12,051
- 1	0	93.50	- 1	(3)	12,079
- 2	0	93.50	- 2	(5)	12,108
- 3	0	93.50	- 3	(8)	12,136
- 4	0	93.50	- 4	(10)	12,165
- 5	0	93.50	- 5	(13)	12,193
- 6	0	93.50	- 6	(15)	12,221
- 7	0	93.50	- 7	(18)	12,250
- 8	0	93.50	- 8	(20)	12,278
- 9	0	93.50	- 9	(23)	12,307
- 10	0	93.50	- 10	(25)	12,335

Weighting Factor: 0.000 Weighting Factor: 0.005

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2019 - December 2019

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	0	88.20	+ 10	37	11,323
+ 9	0	88.03	+ 9	33	11,351
+ 8	0	87.86	+ 8	30	11,378
+ 7	0	87.69	+ 7	26	11,406
+ 6	0	87.52	+ 6	22	11,433
+ 5	0	87.35	+ 5	19	11,461
+ 4	0	87.18	+ 4	15	11,488
+ 3	0	87.01	+ 3	11	11,516
+ 2	0	86.84	+ 2	7	11,543
+ 1	0	86.67	+ 1	4	11,571
				0	11,598
0	0	86.50	0	0	11,673
				0	11,748
- 1	(0)	86.50	- 1	(4)	11,776
- 2	(0)	86.50	- 2	(7)	11,803
- 3	(0)	86.50	- 3	(11)	11,831
- 4	(0)	86.50	- 4	(15)	11,858
- 5	(1)	86.50	- 5	(19)	11,886
- 6	(1)	86.50	- 6	(22)	11,913
- 7	(1)	86.50	- 7	(26)	11,941
- 8	(1)	86.50	- 8	(30)	11,968
- 9	(1)	86.50	- 9	(33)	11,996
- 10	(1)	86.50	- 10	(37)	12,023

Weighting Factor: 0.000 Weighting Factor: 0.008

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2019 - December 2019

Smith 3

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	57	94.00	+ 10	2,923	6,676
+ 9	51	93.96	+ 9	2,631	6,689
+ 8	46	93.92	+ 8	2,338	6,702
+ 7	40	93.88	+ 7	2,046	6,715
+ 6	34	93.84	+ 6	1,754	6,728
+ 5	29	93.80	+ 5	1,462	6,742
+ 4	23	93.76	+ 4	1,169	6,755
+ 3	17	93.72	+ 3	877	6,768
+ 2	11	93.68	+ 2	585	6,781
+ 1	6	93.64	+ 1	292	6,794
				0	6,807
0	0	93.60	0	0	6,882
				0	6,957
- 1	(3)	93.54	- 1	(292)	6,970
- 2	(7)	93.48	- 2	(585)	6,983
- 3	(10)	93.42	- 3	(877)	6,996
- 4	(13)	93.36	- 4	(1,169)	7,009
- 5	(17)	93.30	- 5	(1,462)	7,023
- 6	(20)	93.24	- 6	(1,754)	7,036
- 7	(23)	93.18	- 7	(2,046)	7,049
- 8	(26)	93.12	- 8	(2,338)	7,062
- 9	(30)	93.06	- 9	(2,631)	7,075
- 10	(33)	93.00	- 10	(2,923)	7,088

Weighting Factor: 0.012 Weighting Factor: 0.606

Issued by: Gulf Power Company

GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2019 - December 2019

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)	EAF Adjusted Actual %	Actual Fuel Savings/ Loss ($000)
Scherer 3	0.2	79.5	80.4	78.4	$11	($13)	80.6	$11
Crist 7	0.2	90.2	93.2	85.8	$10	($20)	90.2	$0
Daniel 1	0.0	93.5	95.6	93.5	$0	$0	91.4	$0
Daniel 2	0.0	86.5	88.2	86.5	$0	($1)	81.5	$0
Smith 3	1.2	93.6	94.0	93.0	$57	($33)	94.6	$57
Total:	1.6							

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Max BTU/KWH	ANOHR Range Min BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)	ANOHR Adjusted Actual BTU/KWH	Actual Fuel Savings/ Loss ($000)
Scherer 3	25.0	10,617	64.4	10,936	10,298	$1,205	($1,205)	10,703	($54)
Crist 7	11.6	10,585	66.7	10,903	10,267	$559	($559)	10,594	$0
Daniel 1	0.5	11,976	32.9	12,335	11,617	$25	($25)	11,994	$0
Daniel 2	0.8	11,673	36.0	12,023	11,323	$37	($37)	11,357	$32
Smith 3	60.6	6,882	94.0	7,088	6,676	$2,923	($2,923)	6,880	$0
Total:	98.4								

Issued by: Gulf Power Company

Actual Unit Performance Data

Gulf Power Company

Period of: January 2019 - December 2019

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
Scherer 3	80.0	0.6	80.6
Crist 7	88.5	1.7	90.2
Daniel 1	92.6	-1.2	91.4
Daniel 2	70.9	10.6	81.5
Smith 3	93.8	0.8	94.6

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
Scherer 3	11,002	-299	10,703
Crist 7	10,635	-41	10,594
Daniel 1	11,277	717	11,994
Daniel 2	11,139	218	11,357
Smith 3	6,989	-109	6,880

* Refer to pages 3 through 7, Schedule 2.

** Refer to pages 7 through 11, Schedule 3.

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2019 - December 2019

	SCHERER 3	Jan '19	Feb '19	Mar '19	Apr '19	May '19	Jun '19	
1.	EAF (%)	100.0	1.8	0.0	68.2	100.0	92.7	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	744.0	0.0	0.0	495.1	744.0	683.1	
4.	RSH	0.0	12.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	660.0	743.0	225.0	0.0	36.9	
6.	POH	0.0	648.0	743.0	225.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	12.0	0.0	0.0	0.0	36.9	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	18.5	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	470.0	
11.	PMOH	0.0	0.0	0.0	7.0	0.0	10.7	
12.	LR pm (MW)	0.0	0.0	0.0	530.0	0.0	470.0	
13.	NSC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	
14.	Oper MBtu	3,158,967	0	0	2,301,174	4,047,514	3,112,328	
15.	Net Gen (MWH	286,310	0	0	204,610	375,400	281,035	
16.	ANOHR (Btu/K	11,033	0	0	11,247	10,782	11,075	
17.	NOF %	44.5	0.0	0.0	47.8	58.3	47.6	
18.	NPC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	
19.	ANOHR Equati	10^6 / AKW * [576.13 + 81.47 * APR + 110.08 * MAY + 112.05 * JUN + 141.10 * SEP] + 9,502						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2019 - December 2019

	SCHERER 3	Jul '19	Aug '19	Sep '19	Oct '19	Nov '19	Dec '19	Total
1.	EAF (%)	100.0	99.5	99.6	100.0	100.0	92.2	80.0
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	744.0	720.0	744.0	505.9	162.8	6286.8
4.	RSH	0.0	0.0	0.0	0.0	215.1	523.3	750.4
5.	UH	0.0	0.0	0.0	0.0	0.0	58.0	1722.8
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1616.0
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	MOH	0.0	0.0	0.0	0.0	0.0	58.0	106.9
9.	PFOH	0.0	12.8	10.0	0.0	0.0	0.0	41.3
10.	LR pf (MW)	0.0	250.0	260.0	0.0	0.0	0.0	351.1
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	17.7
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	493.8
13.	NSC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	865.0
14.	Oper MBtu	4,093,432	3,186,534	3,558,697	3,018,745	2,067,597	589,054	29,134,041
15.	Net Gen (MWH	377,350	284,089	327,588	270,936	195,149	45,705	2,648,172
16.	ANOHR (Btu/K	10,848	11,217	10,863	11,142	10,595	12,888	11,002
17.	NOF %	58.6	44.1	52.6	42.1	44.6	32.5	48.7
18.	NPC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	865.0
19.	ANOHR Equati	10^6 / AKW * [576.13 + 81.47 * APR + 110.08 * MAY + 112.05 * JUN + 141.10 * SEP] + 9,502						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2019 - December 2019

	CRIST 7	Jan '19	Feb '19	Mar '19	Apr '19	May '19	Jun '19	
1.	EAF (%)	86.0	100.0	100.0	56.1	100.0	92.8	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	615.9	224.0	743.0	296.9	744.0	668.4	
4.	RSH	24.0	448.0	0.0	111.1	0.0	0.0	
5.	UH	104.1	0.0	0.0	312.0	0.0	51.6	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	104.1	0.0	0.0	312.0	0.0	51.6	
9.	PFOH	0.0	0.0	0.0	9.5	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	206.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	
14.	Oper MBtu	1,914,327	697,815	2,392,933	904,754	2,358,406	2,035,085	
15.	Net Gen (MWH	181,840	66,432	219,428	84,439	221,223	185,647	
16.	ANOHR (Btu/K	10,528	10,504	10,905	10,715	10,661	10,962	
17.	NOF %	62.2	62.4	62.2	59.9	62.6	58.5	
18.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	
19.	ANOHR Equati	10^6 / AKW * [452.14 - 79.14 * FEB - 105.38 * MAR - 156.80 * NOV] + 9,223						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2019 - December 2019

	CRIST 7	Jul '19	Aug '19	Sep '19	Oct '19	Nov '19	Dec '19	Total
1.	EAF (%)	94.6	80.7	84.9	83.2	84.0	100.0	88.5
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	703.5	600.6	611.1	630.3	361.3	731.0	6929.9
4.	RSH	0.0	0.0	0.0	0.0	244.1	13.0	840.2
5.	UH	40.5	143.4	108.9	113.7	115.6	0.0	989.9
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	1.1	0.0	0.0	2.2	1.3	0.0	4.6
8.	MOH	39.4	143.4	108.9	111.6	114.3	0.0	985.3
9.	PFOH	0.0	0.0	0.0	72.8	0.0	6.7	89.0
10.	LR pf (MW)	0.0	0.0	0.0	72.3	0.0	16.3	82.3
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0
14.	Oper MBtu	2,289,619	1,925,536	2,023,269	1,873,121	1,235,946	2,410,190	22,061,000
15.	Net Gen (MWH	211,307	182,381	199,805	181,152	118,793	221,905	2,074,352
16.	ANOHR (Btu/K	10,836	10,558	10,126	10,340	10,404	10,861	10,635
17.	NOF %	63.2	63.9	68.8	60.5	69.2	63.9	63.0
18.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0
19.	ANOHR Equati	10^6 / AKW * [452.14 - 79.14 * FEB - 105.38 * MAR - 156.80 * NOV] + 9,223						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2019 - December 2019

	DANIEL 1	Jan '19	Feb '19	Mar '19	Apr '19	May '19	Jun '19	
1.	EAF (%)	93.8	98.7	77.1	83.2	96.3	99.3	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	286.2	45.4	232.4	720.0	595.7	499.8	
4.	RSH	457.8	626.6	471.5	0.0	148.3	220.3	
5.	UH	0.0	0.0	39.1	0.0	0.0	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	39.1	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	3.6	0.0	19.3	0.0	0.0	1.1	
10.	LR pf (MW)	102.0	0.0	81.0	0.0	0.0	500.0	
11.	PMOH	264.6	52.7	762.6	707.5	161.6	19.7	
12.	LR pm (MW)	86.0	86.0	84.1	86.0	86.0	108.2	
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	
14.	Oper MBtu	569,588	92,558	566,264	1,604,871	1,459,966	1,148,813	
15.	Net Gen (MWH	47,557	7,671	45,643	143,325	131,978	102,545	
16.	ANOHR (Btu/K	11,977	12,066	12,406	11,197	11,062	11,203	
17.	NOF %	33.1	33.6	39.1	39.7	44.1	40.9	
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	
19.	ANOHR Equati	10^6 / AKW * [444.94 - 144.67 * FEB + 78.90 * APR - 18.22 * SEP - 72.06 * OCT - 80.33 * NOV] + 9,337						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2019 - December 2019

	DANIEL 1	Jul '19	Aug '19	Sep '19	Oct '19	Nov '19	Dec '19	Total
1.	EAF (%)	98.0	99.8	99.0	95.5	71.1	100.0	92.6
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	550.9	420.9	693.3	468.5	152.6	0.0	4665.7
4.	RSH	193.1	323.1	26.7	275.5	373.7	744.0	3860.5
5.	UH	0.0	0.0	0.0	0.0	194.8	0.0	233.8
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	0.0	0.0	0.0	2.8	0.0	41.8
8.	MOH	0.0	0.0	0.0	0.0	192.0	0.0	192.0
9.	PFOH	0.0	17.8	0.0	0.0	0.0	0.0	41.8
10.	LR pf (MW)	0.0	32.0	0.0	0.0	0.0	0.0	72.7
11.	PMOH	87.0	0.0	98.3	468.1	193.5	0.0	2815.5
12.	LR pm (MW)	86.0	0.0	36.0	36.0	35.5	0.0	72.1
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0
14.	Oper MBtu	1,319,595	990,119	1,740,242	1,084,856	296,796	0	10,873,668
15.	Net Gen (MWH	117,733	87,521	155,349	96,688	28,242	0	964,252
16.	ANOHR (Btu/K	11,208	11,313	11,202	11,220	10,509	0	11,277
17.	NOF %	42.6	41.4	44.6	41.1	36.9	0.0	41.2
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0
19.	ANOHR Equati	10^6 / AKW * [444.94 - 144.67 * FEB + 78.90 * APR - 18.22 * SEP - 72.06 * OCT - 80.33 * NOV] + 9,337						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2019 - December 2019

	DANIEL 2	Jan '19	Feb '19	Mar '19	Apr '19	May '19	Jun '19	
1.	EAF (%)	85.6	91.8	62.5	81.0	94.4	83.8	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	647.5	21.5	475.6	717.9	429.5	655.6	
4.	RSH	96.5	600.5	156.8	0.0	273.6	0.0	
5.	UH	0.0	50.0	110.6	2.1	40.9	64.4	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	23.5	2.1	0.0	4.9	
8.	MOH	0.0	50.0	87.1	0.0	40.9	59.5	
9.	PFOH	0.0	0.0	2.6	22.8	3.2	26.3	
10.	LR pf (MW)	0.0	0.0	473.0	121.1	102.0	67.5	
11.	PMOH	623.2	28.8	992.2	724.8	0.0	282.9	
12.	LR pm (MW)	86.0	86.0	83.8	89.6	0.0	86.0	
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	
14.	Oper MBtu	1,184,428	33,706	967,330	1,644,215	1,055,166	1,412,402	
15.	Net Gen (MWH	98,754	2,830	88,876	145,415	104,509	125,122	
16.	ANOHR (Btu/K	11,994	11,910	10,884	11,307	10,096	11,288	
17.	NOF %	30.4	26.2	37.2	40.3	48.5	38.0	
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	
19.	ANOHR Equati	10^6 / AKW * [551.33 + 37.93 * JAN - 142.94 * FEB - 122.48 * MAR + 83.72 * APR - 41.35 * OCT - 105.10 * NOV] + 8,822						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2019 - December 2019

	DANIEL 2	Jul '19	Aug '19	Sep '19	Oct '19	Nov '19	Dec '19	Total
1.	EAF (%)	89.4	89.7	95.1	33.8	0.0	44.5	70.9
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	744.0	713.2	263.7	0.0	136.7	5549.1
4.	RSH	0.0	0.0	0.0	0.0	0.0	204.2	1331.5
5.	UH	0.0	0.0	6.8	480.3	721.0	403.2	1879.3
6.	POH	0.0	0.0	0.0	432.0	721.0	383.1	1536.1
7.	FOH	0.0	0.0	6.8	0.0	0.0	20.1	57.4
8.	MOH	0.0	0.0	0.0	48.3	0.0	0.0	285.8
9.	PFOH	0.0	4.1	5.9	0.0	0.0	0.0	64.8
10.	LR pf (MW)	0.0	44.0	500.2	0.0	0.0	0.0	142.0
11.	PMOH	449.9	571.4	314.9	173.5	0.0	156.8	4318.4
12.	LR pm (MW)	87.8	67.1	36.0	36.0	0.0	31.4	76.1
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0
14.	Oper MBtu	1,752,397	1,800,405	1,860,000	614,559	0	288,734	12,613,342
15.	Net Gen (MWH	156,379	159,555	172,284	57,076	0	21,549	1,132,349
16.	ANOHR (Btu/K	11,206	11,284	10,796	10,767	0	13,399	11,139
17.	NOF %	41.9	42.7	48.1	43.1	0.0	31.4	40.6
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0
19.	ANOHR Equati	10^6 / AKW * [551.33 + 37.93 * JAN - 142.94 * FEB - 122.48 * MAR + 83.72 * APR - 41.35 * OCT - 105.10 * NOV] + 8,822						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2019 - December 2019

	SMITH 3	Jan '19	Feb '19	Mar '19	Apr '19	May '19	Jun '19	
1.	EAF (%)	100.0	100.0	100.0	100.0	72.9	97.4	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	744.0	672.0	743.0	720.0	542.3	683.8	
4.	RSH	0.0	0.0	0.0	0.0	0.0	17.6	
5.	UH	0.0	0.0	0.0	0.0	201.7	18.6	
6.	POH	0.0	0.0	0.0	0.0	201.7	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	18.6	
9.	PFOH	0.0	0.0	0.0	6.7	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	16.3	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	621.4	621.4	604.3	604.3	604.3	593.7	
14.	Oper MBtu	2,525,934	2,470,571	2,250,466	1,293,931	998,963	1,387,982	
15.	Net Gen (MWH	362,382	355,633	322,298	184,989	139,755	196,972	
16.	ANOHR (Btu/K	6,970	6,947	6,983	6,995	7,148	7,047	
17.	NOF %	78.4	85.2	71.8	42.5	42.6	48.5	
18.	NPC (MW)	621.4	621.4	604.3	604.3	604.3	593.7	
19.	ANOHR Equati	10^6 / AKW * [324.40 + 51.80 * JUL - 85.12 * OCT] + 6,317						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2019 - December 2019

	SMITH 3	Jul '19	Aug '19	Sep '19	Oct '19	Nov '19	Dec '19	Total
1.	EAF (%)	97.5	99.7	99.3	100.0	59.1	100.0	93.8
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	727.2	744.0	716.8	744.0	426.1	744.0	8207.2
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	17.6
5.	UH	16.8	0.0	3.2	0.0	294.9	0.0	535.2
6.	POH	0.0	0.0	0.0	0.0	294.9	0.0	496.6
7.	FOH	0.0	0.0	3.2	0.0	0.0	0.0	3.2
8.	MOH	16.8	0.0	0.0	0.0	0.0	0.0	35.4
9.	PFOH	9.5	0.0	0.0	0.0	0.0	0.0	16.1
10.	LR pf (MW)	93.0	0.0	0.0	0.0	0.0	0.0	61.2
11.	PMOH	0.0	14.0	14.0	0.0	0.0	0.0	27.9
12.	LR pm (MW)	0.0	93.0	93.0	0.0	0.0	0.0	93.0
13.	NSC (MW)	593.7	593.7	593.7	604.3	604.3	621.4	605.0
14.	Oper MBtu	2,373,987	3,208,943	3,058,093	3,161,919	1,699,809	3,047,008	27,477,607
15.	Net Gen (MWH	333,811	454,677	448,950	448,924	244,166	439,216	3,931,773
16.	ANOHR (Btu/K	7,112	7,058	6,812	7,043	6,962	6,937	6,989
17.	NOF %	77.3	102.9	105.5	99.8	94.8	95.0	79.2
18.	NPC (MW)	593.7	593.7	593.7	604.3	604.3	621.4	605.0
19.	ANOHR Equati	10^6 / AKW * [324.40 + 51.80 * JUL - 85.12 * OCT] + 6,317						

Issued by: Gulf Power Company

Planned Outage Schedules (Actual)

Period of: January 2019 - December 2019

Critical path bar charts of actual work activity performed during major planned outages are not shown here since corresponding bar charts of forecast work activity were not provided earlier in conformance with agreement with Staff to avoid the premature production of charts prior to their normal course of development. Forecast and actual critical path bar charts are developed for each planned outage and, per agreement with Staff, these charts will be provided on request.

Issued by: Gulf Power Company

EXHIBIT TO THE TESTIMONY OF

CHARLES ROTE

IN FPSC DOCKET 20200001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 40
PARTY: GULF POWER COMPANY – DIRECT
DESCRIPTION: Charles Rote CR-1

I. DETERMINATION OF HEAT RATE TARGETS

Target Heat Rate Equations

Scherer 3 ANOHR 10^6 / AKW * [572.88 + 102.03 * JUN + 51.97 * JUL

+ 9,659

Crist 7 ANOHR = 10^6 / AKW * [583.75 + 65.07 * JUN

+ 8,467 + 0.00116 * LSRF / AKW

Daniel 1 ANOHR = 10^6 / AKW * [647.40 - 165.06 * FEB + 160.81 * MAR + 42.47 * JUN - 38.44 * OCT - 94.68 * NOV]

+ 7,789 + 0.00128 * LSRF / AKW

Daniel 2 ANOHR = 10^6 / AKW * [605.35 - 94.66 * MAR + 64.70 * APR]

+ 7,795 + 0.00183 * LSRF / AKW

Smith 3 ANOHR = 10^6 / AKW * [-39.78 - 44.42 * FEB - 102.83 * OCT]

+ 6,994

Where:

ANOHR =	Average Net Operating Heat Rate, BTU/KWH
AKW =	Average Kilowatt Load, KW
LSRF =	Load Square Range Factor, KW^2
BTU/LB =	Coal Burned Average Heat Content, BTU/LB
JAN =	January, 0 if not January, 1 if January
FEB =	February, 0 if not February, 1 if February
MAR =	March, 0 if not March, 1 if March
APR =	April, 0 if not April, 1 if April
MAY =	May, 0 if not May, 1 if May
JUN =	June, 0 if not June, 1 if June
JUL =	July, 0 if not July, 1 if July
AUG =	August, 0 if not August, 1 if August
SEP =	September, 0 if not September, 1 if September
OCT =	October, 0 if not October, 1 if October
NOV =	November, 0 if not November, 1 if November

WEEKLY UNIT OPERATING

DATA USED TO DEVELOP

TARGET HEAT RATE EQUATIONS

Data Base for SCHERER 3 Target Heat Rate Equation

HtRt	HR	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
10610	168	572.56	394246	0	0	0	0	0	0	1	0	0	0	0	0	2017	JUL
10540	168	624.90	458929	0	0	0	0	0	0	1	0	0	0	0	0	2017	
10560	168	628.99	462900	0	0	0	0	0	0	1	0	0	0	0	0	2017	
10585	146	601.40	397138	0	0	0	0	0	0	1	0	0	0	0	0	2017	
10579	168	573.29	390209	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10574	168	533.36	343400	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10446	168	663.76	498544	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10300	168	622.20	453669	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10444	168	539.07	346204	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10861	168	501.85	307597	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11309	168	412.66	207138	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10594	168	671.29	507350	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10659	168	628.32	456310	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10948	168	471.89	270302	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10746	168	581.77	394817	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10800	168	479.40	271563	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11401	168	371.80	155290	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11022	168	390.80	178361	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10253	168	531.51	319892	0	0	0	0	0	0	0	0	0	0	1	0	2017	
10448	168	475.33	256096	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11065	168	332.02	117386	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11736	94	356.05	81551	0	0	0	0	0	0	0	0	0	0	1	0	2017	
10828	168	483.17	285715	0	0	0	0	0	0	0	0	0	0	0	0	2017	
11338	139	394.18	157312	0	0	0	0	0	0	0	0	0	0	0	1	2017	
10296	165	831.41	701486	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10703	168	518.92	337125	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10576	168	549.14	365050	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10850	168	409.38	198042	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10850	168	440.92	235529	0	1	0	0	0	0	0	0	0	0	0	0	2018	
11136	168	347.60	132949	0	1	0	0	0	0	0	0	0	0	0	0	2018	
11471	168	309.68	97260	0	1	0	0	0	0	0	0	0	0	0	0	2018	
11306	168	345.13	138484	0	1	0	0	0	0	0	0	0	0	0	0	2018	
10811	168	467.73	261011	0	0	0	1	0	0	0	0	0	0	0	0	2018	
10626	168	556.36	360054	0	0	0	1	0	0	0	0	0	0	0	0	2018	
11147	168	421.34	205784	0	0	0	1	0	0	0	0	0	0	0	0	2018	
11308	168	400.76	183892	0	0	0	1	0	0	0	0	0	0	0	0	2018	
10845	119	490.01	209218	0	0	0	0	1	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10556	164	613.59	442514	0	0	0	0	1	0	0	0	0	0	0	1	2018	
10747	168	557.52	370465	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10908	168	525.23	330384	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10971	168	504.72	313957	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10972	168	532.90	344199	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10768	168	630.71	462274	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11023	144	548.30	365833	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10879	168	584.89	408202	0	0	0	0	0	0	1	0	0	0	0	0	2018	JUL
10817	168	596.44	420909	0	0	0	0	0	0	1	0	0	0	0	0	2018	
10808	168	613.71	438642	0	0	0	0	0	0	1	0	0	0	0	0	2018	
10850	168	597.85	424515	0	0	0	0	0	0	1	0	0	0	0	0	2018	
10767	168	583.04	402835	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10707	168	627.98	456600	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10691	168	594.28	419929	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10600	168	570.57	389647	0	0	0	0	0	0	0	1	0	0	0	0	2018	

Data Base for SCHERER 3 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR
10519	168	642.25	475036	0	0	0	0	0	0	0	1	0	0	0	0	2018
10546	168	701.02	543561	0	0	0	0	0	0	0	0	1	0	0	0	2018
10515	168	697.92	538222	0	0	0	0	0	0	0	0	1	0	0	0	2018
10335	168	707.73	548644	0	0	0	0	0	0	0	0	1	0	0	0	2018
10563	168	731.10	577202	0	0	0	0	0	0	0	0	1	0	0	0	2018
10662	157	657.12	465458	0	0	0	0	0	0	0	0	0	1	0	0	2018
11065	87	520.98	200316	0	0	0	0	0	0	0	0	0	1	0	1	2018
10510	168	746.71	596887	0	0	0	0	0	0	0	0	0	1	0	0	2018
10841	157	561.25	370782	0	0	0	0	0	0	0	0	0	1	0	0	2018
10605	127	543.35	275153	0	0	0	0	0	0	0	0	0	1	0	1	2018
10539	168	572.54	386175	0	0	0	0	0	0	0	0	0	0	1	0	2018
10597	168	607.32	428322	0	0	0	0	0	0	0	0	0	0	1	0	2018
10233	168	708.19	540908	0	0	0	0	0	0	0	0	0	0	1	0	2018
10202	168	801.80	660266	0	0	0	0	0	0	0	0	0	0	1	0	2018
10514	168	686.24	518104	0	0	0	0	0	0	0	0	0	0	0	0	2018
10686	140	541.46	306465	0	0	0	0	0	0	0	0	0	0	0	0	2018
11362	110	325.25	76951	0	0	0	0	0	0	0	0	0	0	0	1	2018
11668	168	301.73	91094	0	0	0	0	0	0	0	0	0	0	0	0	2018
11445	168	315.18	102532	1	0	0	0	0	0	0	0	0	0	0	0	2019
10796	168	430.40	222437	1	0	0	0	0	0	0	0	0	0	0	0	2019
10641	168	479.54	269709	1	0	0	0	0	0	0	0	0	0	0	0	2019
11374	168	338.59	127434	1	0	0	0	0	0	0	0	0	0	0	0	2019
11356	72	327.89	50300	0	1	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2019
11169	135	474.77	222476	0	0	0	1	0	0	0	0	0	0	0	1	2019
11515	168	352.29	135699	0	0	0	1	0	0	0	0	0	0	0	0	2019
11195	168	402.45	192136	0	0	0	1	0	0	0	0	0	0	0	0	2019
10604	168	562.80	365523	0	0	0	0	1	0	0	0	0	0	0	0	2019
10902	168	451.23	238371	0	0	0	0	1	0	0	0	0	0	0	0	2019
10910	168	439.89	230139	0	0	0	0	1	0	0	0	0	0	0	0	2019
10794	168	534.32	344824	0	0	0	0	1	0	0	0	0	0	0	0	2019
10718	168	537.96	350536	0	0	0	0	1	0	0	0	0	0	0	0	2019
11189	168	364.15	149577	0	0	0	0	0	1	0	0	0	0	0	0	2019
11240	131	401.60	163433	0	0	0	0	0	1	0	0	0	0	0	1	2019
11053	168	412.73	201750	0	0	0	0	0	1	0	0	0	0	0	0	2019
11081	144	434.91	229195	0	0	0	0	0	1	0	0	0	0	0	0	2019
10847	168	539.88	350387	0	0	0	0	0	0	1	0	0	0	0	0	2019
10818	168	570.83	385315	0	0	0	0	0	0	1	0	0	0	0	0	2019
10875	168	488.22	290775	0	0	0	0	0	0	1	0	0	0	0	0	2019
10931	168	443.72	239963	0	0	0	0	0	0	1	0	0	0	0	0	2019
10985	168	402.37	192923	0	0	0	0	0	0	0	1	0	0	0	0	2019
11149	168	386.39	165264	0	0	0	0	0	0	0	1	0	0	0	0	2019
11091	168	410.99	189851	0	0	0	0	0	0	0	1	0	0	0	0	2019
11233	168	386.59	167457	0	0	0	0	0	0	0	1	0	0	0	0	2019
11399	168	360.92	139932	0	0	0	0	0	0	0	1	0	0	0	0	2019
10808	168	613.71	438642	0	0	0	0	0	0	1	0	0	0	0	0	2018

Data Base for SCHERER 3 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR
10915	168	449.26	229896	0	0	0	0	0	0	0	0	1	0	0	0	2019
10776	168	493.31	282234	0	0	0	0	0	0	0	0	1	0	0	0	2019
10881	168	447.73	234139	0	0	0	0	0	0	0	0	1	0	0	0	2019
10865	168	437.96	216166	0	0	0	0	0	0	0	0	1	0	0	0	2019
10910	168	429.77	214267	0	0	0	0	0	0	0	0	0	1	0	0	2019
11153	168	358.64	142542	0	0	0	0	0	0	0	0	0	1	0	0	2019
11315	168	337.20	120572	0	0	0	0	0	0	0	0	0	1	0	0	2019
11195	168	338.79	120793	0	0	0	0	0	0	0	0	0	1	0	0	2019
11078	168	350.77	132226	0	0	0	0	0	0	0	0	0	1	0	0	2019
10436	168	407.60	178941	0	0	0	0	0	0	0	0	0	0	1	0	2019
10629	168	390.19	166387	0	0	0	0	0	0	0	0	0	0	1	0	2019
10522	97	398.78	120803	0	0	0	0	0	0	0	0	0	0	1	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2019
11832	152	308.66	99498	0	0	0	0	0	0	0	0	0	0	0	1	2019
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2020
12096	71	308.48	43478	1	0	0	0	0	0	0	0	0	0	0	1	2020
11159	67	399.93	83009	1	0	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	0	1	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	0	1	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	0	1	0	0	0	0	0	0	2020
12533	147	333.48	123423	0	0	0	0	0	1	0	0	0	0	0	1	2020

HtRt	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hr	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
J to N	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
YR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 7 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
10565	168	337.15	124845	0	0	0	0	0	0	1	0	0	0	0	0	2017	JUL
10530	168	316.18	106904	0	0	0	0	0	0	1	0	0	0	0	0	2017	
10402	168	357.85	133880	0	0	0	0	0	0	1	0	0	0	0	0	2017	
10688	72	307.18	42538	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10470	109	343.27	91015	0	0	0	0	0	0	0	1	0	0	0	1	2017	
10745	168	373.48	145617	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10784	120	306.82	69298	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10780	82	338.63	65731	0	0	0	0	0	0	0	1	0	0	0	1	2017	
10716	168	347.29	128596	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10637	168	337.30	117547	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10497	49	322.94	31897	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10694	131	370.98	118213	0	0	0	0	0	0	0	0	1	0	0	1	2017	
10651	168	343.42	125155	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10842	166	349.87	127263	0	0	0	0	0	0	0	0	0	1	0	0	2017	
9855	98	316.53	64577	0	0	0	0	0	0	0	0	0	1	0	1	2017	
10708	168	284.41	84739	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10882	82	249.59	35235	0	0	0	0	0	0	0	0	0	1	0	0	2017	
9921	72	338.96	53187	0	0	0	0	0	0	0	0	0	0	1	1	2017	
9882	168	310.49	101792	0	0	0	0	0	0	0	0	0	0	1	0	2017	
10223	168	281.00	83366	0	0	0	0	0	0	0	0	0	0	1	0	2017	
10130	96	277.38	46482	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11409	167	300.26	95703	0	0	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2017	
11924	118	272.11	60659	0	0	0	0	0	0	0	0	0	0	0	1	2017	
10231	168	440.12	198087	1	0	0	0	0	0	0	0	0	0	0	0	2018	JAN
10425	46	308.96	27537	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10441	80	374.80	83825	1	0	0	0	0	0	0	0	0	0	0	1	2018	
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10287	154	355.23	129137	0	1	0	0	0	0	0	0	0	0	0	1	2018	
10351	24	263.46	12583	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
10793	84	279.35	50334	0	0	0	0	1	0	0	0	0	0	0	2	2018	
10331	168	352.96	133946	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10407	132	354.58	117516	0	0	0	0	1	0	0	0	0	0	0	1	2018	
10804	96	262.98	55498	0	0	0	0	1	0	0	0	0	0	0	1	2018	
10962	168	213.24	45559	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11432	60	231.70	28336	0	0	0	0	0	1	0	0	0	0	0	1	2018	
10734	168	319.64	110934	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10643	168	380.42	155449	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10615	144	344.71	129166	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10766	141	328.64	102145	0	0	0	0	0	0	1	0	0	0	0	1	2018	JUL
10647	168	350.81	134348	0	0	0	0	0	0	1	0	0	0	0	0	2018	
10758	116	358.07	99113	0	0	0	0	0	0	1	0	0	0	0	0	2018	

Data Base for CRIST 7 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
10015	150	355.30	127774	0	0	0	0	0	0	1	0	0	0	0	1	2018	
10068	168	340.14	126220	0	0	0	0	0	0	0	1	0	0	0	0	2018	
9791	168	376.65	151048	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10473	168	341.43	124783	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10821	142	325.25	96631	0	0	0	0	0	0	0	1	0	0	0	0	2018	
0	0	0.00	0	0	0	0	0	0	0	0	1	0	0	0	0	2018	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2018	
11016	159	368.25	144102	0	0	0	0	0	0	0	0	1	0	0	1	2018	
10645	168	393.90	164935	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10549	168	410.24	176442	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10313	168	386.49	159371	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10081	168	398.17	168729	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10102	168	427.77	189528	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10238	168	303.49	97389	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10308	168	328.04	113931	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10408	168	351.03	128917	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10409	168	380.64	150118	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10126	168	392.41	156735	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10456	162	367.73	138208	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10634	168	380.32	147977	0	0	0	0	0	0	0	0	0	0	0	0	2018	
10626	168	376.93	148542	0	0	0	0	0	0	0	0	0	0	0	0	2018	
10934	168	273.82	78066	0	0	0	0	0	0	0	0	0	0	0	0	2018	
11171	168	245.02	60049	0	0	0	0	0	0	0	0	0	0	0	0	2018	
10885	168	246.56	60868	1	0	0	0	0	0	0	0	0	0	0	0	2019	JAN
10766	168	249.58	62698	1	0	0	0	0	0	0	0	0	0	0	0	2019	
10450	82	272.49	42049	1	0	0	0	0	0	0	0	0	0	0	0	2019	
9999	126	357.31	100897	1	0	0	0	0	0	0	0	0	0	0	1	2019	
10173	168	360.75	136522	0	1	0	0	0	0	0	0	0	0	0	0	2019	
10808	109	297.64	68403	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
10761	114	292.18	65393	0	0	1	0	0	0	0	0	0	0	0	1	2019	
10678	167	325.31	113474	0	0	1	0	0	0	0	0	0	0	0	0	2019	
10982	168	274.74	77125	0	0	1	0	0	0	0	0	0	0	0	0	2019	
11235	168	272.86	75333	0	0	1	0	0	0	0	0	0	0	0	0	2019	
10517	168	307.32	101130	0	0	1	0	0	0	0	0	0	0	0	0	2019	
10493	168	288.85	90509	0	0	0	1	0	0	0	0	0	0	0	0	2019	
11011	72	275.89	34044	0	0	0	1	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2019	
10933	168	297.08	94607	0	0	0	0	1	0	0	0	0	0	0	0	2019	
11003	168	291.64	89583	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10772	168	322.23	111241	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10114	168	327.18	115238	0	0	0	0	1	0	0	0	0	0	0	0	2019	
11132	168	264.57	72299	0	0	0	0	0	1	0	0	0	0	0	0	2019	
11363	168	252.71	64529	0	0	0	0	0	1	0	0	0	0	0	0	2019	
11287	165	294.91	93138	0	0	0	0	0	1	0	0	0	0	0	0	2019	
10585	92	294.85	61088	0	0	0	0	0	1	0	0	0	0	0	0	2019	
11093	127	316.18	88523	0	0	0	0	0	0	1	0	0	0	0	1	2019	
10382	168	322.24	110600	0	0	0	0	0	0	1	0	0	0	0	0	2019	
10778	168	292.42	91073	0	0	0	0	0	0	1	0	0	0	0	0	2019	
10883	168	279.80	81768	0	0	0	0	0	0	1	0	0	0	0	0	2019	
11219	94	286.15	49224	0	0	0	0	0	0	0	1	0	0	0	0	2019	
10251	98	305.97	59563	0	0	0	0	0	0	0	1	0	0	0	1	2019	

Data Base for CRIST 7 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR
10642	168	329.23	116546	0	0	0	0	0	0	0	1	0	0	0	0	2019
10633	168	302.77	97915	0	0	0	0	0	0	0	1	0	0	0	0	2019
10774	168	282.45	83967	0	0	0	0	0	0	0	1	0	0	0	0	2019
10737	168	337.82	122643	0	0	0	0	0	0	0	0	1	0	0	0	2019
10409	168	341.94	125266	0	0	0	0	0	0	0	0	1	0	0	0	2019
10831	59	276.49	33544	0	0	0	0	0	0	0	0	1	0	0	1	2019
10092	143	297.23	80557	0	0	0	0	0	0	0	0	0	1	0	0	2019
11289	120	259.53	51100	0	0	0	0	0	0	0	0	0	1	0	1	2019
10356	157	263.48	70156	0	0	0	0	0	0	0	0	0	1	0	0	2019
10197	65	291.88	37951	0	0	0	0	0	0	0	0	0	1	0	0	2019
10067	117	305.91	67848	0	0	0	0	0	0	0	0	0	0	1	0	2019
10239	168	328.07	110164	0	0	0	0	0	0	0	0	0	0	0	0	2019
10849	168	306.29	96410	0	0	0	0	0	0	0	0	0	0	0	0	2019
11083	168	320.31	105949	0	0	0	0	0	0	0	0	0	0	0	0	2019
11515	168	263.70	70619	0	0	0	0	0	0	0	0	0	0	0	0	2019
11003	168	273.36	76476	1	0	0	0	0	0	0	0	0	0	0	0	2020
10503	168	339.54	118417	1	0	0	0	0	0	0	0	0	0	0	0	2020
11914	168	292.10	87354	0	1	0	0	0	0	0	0	0	0	0	0	2020
11268	168	288.10	85831	0	1	0	0	0	0	0	0	0	0	0	0	2020
11252	168	298.29	93484	0	1	0	0	0	0	0	0	0	0	0	0	2020
10706	168	271.32	75142	0	0	1	0	0	0	0	0	0	0	0	0	2020
10452	167	264.10	72721	0	0	1	0	0	0	0	0	0	0	0	0	2020
10524	166	241.77	58711	0	0	1	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	0	1	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	0	1	0	0	0	0	0	0	2020
12970	136	198.36	36530	0	0	0	0	0	1	0	0	0	0	0	1	2020
0	0	0.00	0	0	0	0	0	0	1	0	0	0	0	0	0	2020

Data Base for CRIST 7 Target Heat Rate Equation

HtRt	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hr	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
J to N	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
YR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 1 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
12333	168	154.28	25121	0	0	0	0	0	0	1	0	0	0	0	0	2017	JUL
12122	99	142.32	14220	0	0	0	0	0	0	1	0	0	0	0	1	2017	
11076	168	197.22	50243	0	0	0	0	0	0	1	0	0	0	0	0	2017	
12232	168	159.79	27801	0	0	0	0	0	0	1	0	0	0	0	0	2017	
12049	163	161.87	32718	0	0	0	0	0	0	0	1	0	0	0	0	2017	
12120	168	149.31	23920	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11580	168	175.78	34362	0	0	0	0	0	0	0	1	0	0	0	0	2017	
12075	168	157.60	26806	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11934	168	155.08	29376	0	0	0	0	0	0	0	1	0	0	0	0	2017	
12190	168	146.00	22683	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11661	168	158.71	31082	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11347	168	181.28	36988	0	0	0	0	0	0	0	0	1	0	0	0	2017	
12024	168	163.50	29534	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11212	168	206.05	54021	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11793	168	177.04	40565	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11446	168	193.79	48490	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11552	168	174.27	35830	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11440	168	186.18	43268	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10459	168	273.54	84948	0	0	0	0	0	0	0	0	0	0	1	0	2017	
10738	168	213.07	63616	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11657	168	139.64	19722	0	0	0	0	0	0	0	0	0	0	1	0	2017	
12045	119	133.07	12713	0	0	0	0	0	0	0	0	0	0	1	0	2017	
13645	56	147.04	9314	0	0	0	0	0	0	0	0	0	0	0	1	2017	
12520	168	160.57	26156	0	0	0	0	0	0	0	0	0	0	0	0	2017	
12696	11	149.27	3381	0	0	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2017	
10940	168	188.90	38819	1	0	0	0	0	0	0	0	0	0	0	0	2018	
11510	168	187.68	36913	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10667	165	207.21	46811	1	0	0	0	0	0	0	0	0	0	0	0	2018	
12546	166	171.64	29783	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10711	168	180.20	33203	0	1	0	0	0	0	0	0	0	0	0	0	2018	
10693	45	165.80	8171	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
13160	85	165.15	17113	0	0	0	1	0	0	0	0	0	0	0	1	2018	
12029	166	184.15	43175	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11419	168	185.63	40293	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10822	48	188.48	11706	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11693	141	194.39	35130	0	0	0	0	1	0	0	0	0	0	0	1	2018	
11298	168	206.64	44532	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11861	162	178.49	37661	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11737	168	207.05	44553	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11241	168	249.68	65612	0	0	0	0	0	1	0	0	0	0	0	0	2018	
12449	144	162.89	28731	0	0	0	0	0	1	0	0	0	0	0	0	2018	
12118	168	151.79	24587	0	0	0	0	0	0	1	0	0	0	0	0	2018	JUL

Data Base for DANIEL 1 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR
11990	168	161.01	28252	0	0	0	0	0	0	1	0	0	0	0	0	2018
11779	168	163.07	30807	0	0	0	0	0	0	1	0	0	0	0	0	2018
12378	168	142.65	20765	0	0	0	0	0	0	1	0	0	0	0	0	2018
11841	168	148.36	23062	0	0	0	0	0	0	0	1	0	0	0	0	2018
11364	168	182.65	38044	0	0	0	0	0	0	0	1	0	0	0	0	2018
12212	15	139.53	2946	0	0	0	0	0	0	0	1	0	0	0	0	2018
12120	65	163.31	12845	0	0	0	0	0	0	0	1	0	0	0	1	2018
11589	168	160.54	27634	0	0	0	0	0	0	0	1	0	0	0	0	2018
12132	168	169.49	30007	0	0	0	0	0	0	0	0	1	0	0	0	2018
11557	168	198.58	40551	0	0	0	0	0	0	0	0	1	0	0	0	2018
10562	168	240.04	59346	0	0	0	0	0	0	0	0	1	0	0	0	2018
10748	126	238.63	47684	0	0	0	0	0	0	0	0	1	0	0	1	2018
9894	135	281.04	72586	0	0	0	0	0	0	0	0	0	1	0	1	2018
10212	142	293.82	76040	0	0	0	0	0	0	0	0	0	1	0	0	2018
11047	97	206.07	29325	0	0	0	0	0	0	0	0	0	1	0	1	2018
11893	111	146.36	15474	0	0	0	0	0	0	0	0	0	1	0	1	2018
11693	168	160.30	25818	0	0	0	0	0	0	0	0	0	1	0	0	2018
10881	168	198.36	42456	0	0	0	0	0	0	0	0	0	0	1	0	2018
12161	168	152.08	24248	0	0	0	0	0	0	0	0	0	0	1	0	2018
10385	168	211.79	48435	0	0	0	0	0	0	0	0	0	0	0	0	2018
10448	147	228.07	53859	0	0	0	0	0	0	0	0	0	0	0	0	2018
11615	109	155.94	18635	0	0	0	0	0	0	0	0	0	0	0	1	2018
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2019
13566	46	139.54	5834	1	0	0	0	0	0	0	0	0	0	0	1	2019
12500	168	169.45	30179	1	0	0	0	0	0	0	0	0	0	0	0	2019
10777	117	173.86	21724	0	1	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019
12261	18	221.89	7912	0	0	1	0	0	0	0	0	0	0	0	1	2019
12098	145	187.89	33473	0	0	1	0	0	0	0	0	0	0	0	0	2019
11001	168	193.84	39273	0	0	0	1	0	0	0	0	0	0	0	0	2019
10940	168	212.03	47104	0	0	0	1	0	0	0	0	0	0	0	0	2019
11564	168	189.65	37040	0	0	0	1	0	0	0	0	0	0	0	0	2019
11521	168	190.25	37373	0	0	0	1	0	0	0	0	0	0	0	0	2019
11471	168	215.40	50040	0	0	0	0	1	0	0	0	0	0	0	0	2019
10742	71	186.13	15250	0	0	0	0	1	0	0	0	0	0	0	0	2019
11100	116	223.09	38697	0	0	0	0	1	0	0	0	0	0	0	1	2019
10977	168	225.67	55082	0	0	0	0	1	0	0	0	0	0	0	0	2019
10548	168	248.63	70182	0	0	0	0	1	0	0	0	0	0	0	0	2019
11216	95	184.41	20164	0	0	0	0	0	1	0	0	0	0	0	0	2019
12077	19	179.74	5382	0	0	0	0	0	1	0	0	0	0	0	1	2019
11288	168	216.12	52758	0	0	0	0	0	1	0	0	0	0	0	0	2019
11370	144	197.44	41705	0	0	0	0	0	1	0	0	0	0	0	0	2019
10997	168	217.96	51321	0	0	0	0	0	0	1	0	0	0	0	0	2019
11265	168	218.43	51412	0	0	0	0	0	0	1	0	0	0	0	0	2019
11340	168	208.55	47788	0	0	0	0	0	0	1	0	0	0	0	0	2019
11313	47	199.62	12298	0	0	0	0	0	0	1	0	0	0	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	1	0	0	0	0	2019
11472	129	200.93	35511	0	0	0	0	0	0	0	1	0	0	0	1	2019
11539	168	212.91	48965	0	0	0	0	0	0	0	1	0	0	0	0	2019

Data Base for DANIEL 1 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR
10842	123	210.02	36453	0	0	0	0	0	0	0	1	0	0	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	1	0	0	0	0	2019
11231	165	225.59	55257	0	0	0	0	0	0	0	0	1	0	0	1	2019
11149	168	227.27	56369	0	0	0	0	0	0	0	0	1	0	0	0	2019
11181	168	219.40	52420	0	0	0	0	0	0	0	0	1	0	0	0	2019
11181	168	225.95	55282	0	0	0	0	0	0	0	0	1	0	0	0	2019
11373	168	207.31	45223	0	0	0	0	0	0	0	0	0	1	0	0	2019
11515	168	188.44	36456	0	0	0	0	0	0	0	0	0	1	0	0	2019
10712	119	232.84	44484	0	0	0	0	0	0	0	0	0	1	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2019
10863	110	190.31	27485	0	0	0	0	0	0	0	0	0	1	0	1	2019
10362	63	195.38	18024	0	0	0	0	0	0	0	0	0	0	1	1	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2020
11943	38	213.84	14881	1	0	0	0	0	0	0	0	0	0	0	1	2020
11083	35	188.91	10180	1	0	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
11175	116	184.09	25107	0	0	0	0	1	0	0	0	0	0	0	0	2020
11791	90	171.96	17511	0	0	0	0	1	0	0	0	0	0	0	0	2020
11508	139	185.91	30297	0	0	0	0	1	0	0	0	0	0	0	1	2020
11416	168	183.89	34509	0	0	0	0	1	0	0	0	0	0	0	0	2020
11919	168	184.51	35108	0	0	0	0	1	0	0	0	0	0	0	0	2020
11989	168	177.23	31892	0	0	0	0	0	1	0	0	0	0	0	0	2020
11859	168	175.10	30833	0	0	0	0	0	1	0	0	0	0	0	0	2020
11636	168	178.27	32345	0	0	0	0	0	1	0	0	0	0	0	0	2020
11625	168	205.86	46717	0	0	0	0	0	1	0	0	0	0	0	0	2020

HtRt	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hr	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
J to N	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
YR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 2 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
12084	168	169.63	31495	0	0	0	0	0	0	1	0	0	0	0	0	2017	JUL
11953	163	157.74	26600	0	0	0	0	0	0	1	0	0	0	0	0	2017	
11488	168	206.37	53221	0	0	0	0	0	0	1	0	0	0	0	0	2017	
11547	168	185.93	40756	0	0	0	0	0	0	1	0	0	0	0	0	2017	
11908	168	172.68	36350	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11987	168	155.45	26168	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11322	168	202.13	45994	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11203	168	199.54	47681	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11955	168	165.02	31893	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11933	168	164.66	32134	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11986	167	145.84	22911	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10995	168	227.79	60429	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11543	168	192.67	42900	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11265	168	173.67	37370	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11130	168	192.77	46312	0	0	0	0	0	0	0	0	0	1	0	0	2017	
12080	78	192.38	24658	0	0	0	0	0	0	0	0	0	1	0	0	2017	
13838	27	134.78	4602	0	0	0	0	0	0	0	0	0	1	0	1	2017	
12542	168	141.52	20398	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11980	168	164.19	32521	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11024	168	213.70	63200	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11630	168	150.30	22954	0	0	0	0	0	0	0	0	0	0	1	0	2017	
12152	168	140.32	19830	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11915	168	153.26	24771	0	0	0	0	0	0	0	0	0	0	0	0	2017	
11804	162	172.36	31084	0	0	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2017	
10953	168	250.05	72422	1	0	0	0	0	0	0	0	0	0	0	0	2018	
11735	168	209.99	50277	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10933	156	226.03	55739	1	0	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10630	140	188.52	32287	0	1	0	0	0	0	0	0	0	0	0	1	2018	
10106	70	186.01	16526	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
10859	65	228.52	26345	0	0	1	0	0	0	0	0	0	0	0	1	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
12363	113	176.47	25723	0	0	0	1	0	0	0	0	0	0	0	1	2018	
12375	22	165.50	4108	0	0	0	1	0	0	0	0	0	0	0	0	2018	
12218	150	159.89	27582	0	0	0	0	1	0	0	0	0	0	0	1	2018	
11407	168	193.79	44711	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11312	168	177.63	37728	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10824	168	304.90	106007	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11167	168	216.42	49781	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11384	156	183.32	39462	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11222	168	211.73	48122	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10695	167	272.66	80408	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11572	144	184.31	38872	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11513	168	167.18	30955	0	0	0	0	0	0	1	0	0	0	0	0	2018	JUL

Data Base for DANIEL 2 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR
12172	168	174.82	33453	0	0	0	0	0	0	1	0	0	0	0	0	2018
11805	168	162.99	28238	0	0	0	0	0	0	1	0	0	0	0	0	2018
11239	168	161.42	27889	0	0	0	0	0	0	1	0	0	0	0	0	2018
11914	168	162.34	28688	0	0	0	0	0	0	0	1	0	0	0	0	2018
11347	143	177.41	30122	0	0	0	0	0	0	0	1	0	0	0	0	2018
11373	157	171.93	33617	0	0	0	0	0	0	0	1	0	0	0	1	2018
11506	168	215.38	50394	0	0	0	0	0	0	0	1	0	0	0	0	2018
11659	168	182.15	37223	0	0	0	0	0	0	0	1	0	0	0	0	2018
11838	167	173.40	33199	0	0	0	0	0	0	0	0	1	0	0	0	2018
11409	168	197.20	40969	0	0	0	0	0	0	0	0	1	0	0	0	2018
10954	140	230.48	51651	0	0	0	0	0	0	0	0	1	0	0	1	2018
10839	168	246.98	62222	0	0	0	0	0	0	0	0	1	0	0	0	2018
10495	168	273.57	78083	0	0	0	0	0	0	0	0	0	1	0	0	2018
10775	168	219.28	52280	0	0	0	0	0	0	0	0	0	1	0	0	2018
10940	168	208.15	46968	0	0	0	0	0	0	0	0	0	1	0	0	2018
11880	145	141.00	17564	0	0	0	0	0	0	0	0	0	1	0	0	2018
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2018
12546	143	151.04	20881	0	0	0	0	0	0	0	0	0	0	1	1	2018
11768	168	186.52	40212	0	0	0	0	0	0	0	0	0	0	1	0	2018
11632	168	156.80	26691	0	0	0	0	0	0	0	0	0	0	1	0	2018
10758	168	258.78	83332	0	0	0	0	0	0	0	0	0	0	1	0	2018
10979	165	186.65	39330	0	0	0	0	0	0	0	0	0	0	0	0	2018
11515	163	179.66	36296	0	0	0	0	0	0	0	0	0	0	0	0	2018
11447	163	159.61	27294	0	0	0	0	0	0	0	0	0	0	0	0	2018
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2018
12171	71	153.89	10476	1	0	0	0	0	0	0	0	0	0	0	1	2019
11979	168	147.24	22231	1	0	0	0	0	0	0	0	0	0	0	0	2019
11873	168	153.68	25063	1	0	0	0	0	0	0	0	0	0	0	0	2019
12235	168	150.61	24726	1	0	0	0	0	0	0	0	0	0	0	0	2019
11669	93	159.14	14612	0	1	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019
11264	64	168.58	15670	0	0	1	0	0	0	0	0	0	0	0	0	2019
10931	32	188.25	9454	0	0	1	0	0	0	0	0	0	0	0	1	2019
9952	168	191.46	43042	0	0	1	0	0	0	0	0	0	0	0	0	2019
10713	168	212.93	54121	0	0	1	0	0	0	0	0	0	0	0	0	2019
11371	166	189.28	39898	0	0	0	1	0	0	0	0	0	0	0	0	2019
11014	167	224.24	56962	0	0	0	1	0	0	0	0	0	0	0	0	2019
11590	168	192.45	40982	0	0	0	1	0	0	0	0	0	0	0	0	2019
11510	163	197.59	43420	0	0	0	1	0	0	0	0	0	0	0	0	2019
9952	97	252.09	43029	0	0	0	0	1	0	0	0	0	0	0	0	2019
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2019
9923	92	238.91	37414	0	0	0	0	1	0	0	0	0	0	0	1	2019
10348	168	236.02	65471	0	0	0	0	1	0	0	0	0	0	0	0	2019
10204	109	248.71	52027	0	0	0	0	1	0	0	0	0	0	0	1	2019
11359	168	167.57	31152	0	0	0	0	0	1	0	0	0	0	0	0	2019
11765	168	174.81	34319	0	0	0	0	0	1	0	0	0	0	0	0	2019
10882	164	216.26	58475	0	0	0	0	0	1	0	0	0	0	0	0	2019
11045	144	203.48	51375	0	0	0	0	0	1	0	0	0	0	0	0	2019
10839	168	223.98	58479	0	0	0	0	0	0	1	0	0	0	0	0	2019
10994	168	231.75	61513	0	0	0	0	0	0	1	0	0	0	0	0	2019
11145	166	208.96	51519	0	0	0	0	0	0	1	0	0	0	0	0	2019

Data Base for DANIEL 2 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR
11819	168	188.11	39487	0	0	0	0	0	0	1	0	0	0	0	0	2019
11949	168	189.45	40680	0	0	0	0	0	0	0	1	0	0	0	0	2019
11096	168	214.58	54504	0	0	0	0	0	0	0	1	0	0	0	0	2019
10989	168	231.86	63626	0	0	0	0	0	0	0	1	0	0	0	0	2019
11299	168	233.44	69291	0	0	0	0	0	0	0	1	0	0	0	0	2019
11341	168	191.60	42642	0	0	0	0	0	0	0	1	0	0	0	0	2019
10790	166	244.60	71931	0	0	0	0	0	0	0	0	1	0	0	0	2019
10704	163	254.69	76111	0	0	0	0	0	0	0	0	1	0	0	0	2019
10914	164	230.69	63898	0	0	0	0	0	0	0	0	1	0	0	0	2019
10818	168	244.94	69825	0	0	0	0	0	0	0	0	1	0	0	0	2019
10526	168	233.80	63216	0	0	0	0	0	0	0	0	0	1	0	0	2019
10947	120	198.56	32762	0	0	0	0	0	0	0	0	0	1	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2019
-1386	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2019
12029	124	177.93	31980	0	0	0	0	0	0	0	0	0	0	0	1	2019
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2020
11366	75	194.73	21687	1	0	0	0	0	0	0	0	0	0	0	1	2020
12103	168	152.33	25065	1	0	0	0	0	0	0	0	0	0	0	0	2020
12654	161	140.87	20122	0	1	0	0	0	0	0	0	0	0	0	0	2020
12202	108	168.79	23617	0	1	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2020
11956	156	144.32	21778	0	0	1	0	0	0	0	0	0	0	0	1	2020
11718	167	147.95	22808	0	0	1	0	0	0	0	0	0	0	0	0	2020
11678	168	144.02	21019	0	0	1	0	0	0	0	0	0	0	0	0	2020
11726	166	145.46	22153	0	0	1	0	0	0	0	0	0	0	0	0	2020
10949	141	153.48	21933	0	0	1	0	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2020
12364	68	197.72	20716	0	0	0	0	1	0	0	0	0	0	0	1	2020
11290	168	185.02	38253	0	0	0	0	0	1	0	0	0	0	0	0	2020
11693	168	163.77	30392	0	0	0	0	0	1	0	0	0	0	0	0	2020
11717	165	150.60	23872	0	0	0	0	0	1	0	0	0	0	0	0	2020
11176	168	186.38	42092	0	0	0	0	0	1	0	0	0	0	0	0	2020

HtRt	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hr	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
J to N	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
YR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 3 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
7114	168	503.93	260260	0	0	0	0	0	0	1	0	0	0	0	0	2017	JUL
7142	168	513.93	269980	0	0	0	0	0	0	1	0	0	0	0	0	2017	
7142	168	514.32	270531	0	0	0	0	0	0	1	0	0	0	0	0	2017	
6981	168	522.38	276550	0	0	0	0	0	0	1	0	0	0	0	0	2017	
6986	168	513.23	268860	0	0	0	0	0	0	0	1	0	0	0	0	2017	
7111	168	519.55	273245	0	0	0	0	0	0	0	1	0	0	0	0	2017	
7233	168	535.57	288881	0	0	0	0	0	0	0	1	0	0	0	0	2017	
6982	168	499.86	254180	0	0	0	0	0	0	0	1	0	0	0	0	2017	
6760	131	507.34	221630	0	0	0	0	0	0	0	1	0	0	0	1	2017	
6892	168	512.79	268030	0	0	0	0	0	0	0	0	1	0	0	0	2017	
6957	168	443.57	208983	0	0	0	0	0	0	0	0	1	0	0	0	2017	
6817	168	543.92	297026	0	0	0	0	0	0	0	0	1	0	0	0	2017	
6588	168	533.24	286068	0	0	0	0	0	0	0	0	1	0	0	0	2017	
6698	168	520.57	273757	0	0	0	0	0	0	0	0	0	1	0	0	2017	
6915	168	524.19	276836	0	0	0	0	0	0	0	0	0	1	0	0	2017	
6755	168	523.05	276729	0	0	0	0	0	0	0	0	0	1	0	0	2017	
6686	168	510.89	264611	0	0	0	0	0	0	0	0	0	1	0	0	2017	
6863	168	551.19	305124	0	0	0	0	0	0	0	0	0	1	0	0	2017	
7032	120	554.82	222739	0	0	0	0	0	0	0	0	0	0	1	0	2017	
6968	168	480.81	237807	0	0	0	0	0	0	0	0	0	0	1	0	2017	
6873	168	521.29	274334	0	0	0	0	0	0	0	0	0	0	1	0	2017	
6956	155	526.39	278443	0	0	0	0	0	0	0	0	0	0	0	0	2017	
6889	168	570.82	327256	0	0	0	0	0	0	0	0	0	0	0	0	2017	
6895	164	498.59	255660	0	0	0	0	0	0	0	0	0	0	0	0	2017	
6929	168	515.48	275897	0	0	0	0	0	0	0	0	0	0	0	0	2017	
6931	168	569.98	333381	1	0	0	0	0	0	0	0	0	0	0	0	2018	JAN
6974	168	496.04	261856	1	0	0	0	0	0	0	0	0	0	0	0	2018	
6951	168	542.71	303020	1	0	0	0	0	0	0	0	0	0	0	0	2018	
7013	168	476.18	241270	1	0	0	0	0	0	0	0	0	0	0	0	2018	
6912	144	503.09	224192	0	1	0	0	0	0	0	0	0	0	0	0	2018	
6943	168	461.39	228004	0	1	0	0	0	0	0	0	0	0	0	0	2018	
7012	168	444.28	216613	0	1	0	0	0	0	0	0	0	0	0	0	2018	
6804	168	512.17	266640	0	1	0	0	0	0	0	0	0	0	0	0	2018	
6797	168	519.15	271330	0	0	1	0	0	0	0	0	0	0	0	0	2018	
6913	149	498.92	238748	0	0	1	0	0	0	0	0	0	0	0	0	2018	
6893	168	516.96	275002	0	0	1	0	0	0	0	0	0	0	0	0	2018	
6940	168	513.57	269160	0	0	1	0	0	0	0	0	0	0	0	0	2018	
6896	144	520.34	238218	0	0	1	0	0	0	0	0	0	0	0	0	2018	
6744	168	536.93	293554	0	0	0	1	0	0	0	0	0	0	0	0	2018	
6713	168	553.95	308278	0	0	0	1	0	0	0	0	0	0	0	0	2018	
6686	168	547.45	301399	0	0	0	1	0	0	0	0	0	0	0	0	2018	
6735	168	515.02	274059	0	0	0	1	0	0	0	0	0	0	0	0	2018	
6742	168	524.11	281447	0	0	0	0	1	0	0	0	0	0	0	0	2018	
6869	168	489.53	254728	0	0	0	0	1	0	0	0	0	0	0	0	2018	
7058	70	303.34	45198	0	0	0	0	1	0	0	0	0	0	0	0	2018	
7181	34	418.18	48894	0	0	0	0	1	0	0	0	0	0	0	1	2018	
7032	144	422.85	171070	0	0	0	0	1	0	0	0	0	0	0	0	2018	
7099	168	479.27	244454	0	0	0	0	0	1	0	0	0	0	0	0	2018	
7099	168	492.67	252798	0	0	0	0	0	1	0	0	0	0	0	0	2018	
7084	168	520.40	275042	0	0	0	0	0	1	0	0	0	0	0	0	2018	
6860	144	489.69	248398	0	0	0	0	0	1	0	0	0	0	0	0	2018	
6839	168	515.08	269230	0	0	0	0	0	0	1	0	0	0	0	0	2018	JUL
6969	168	525.01	278809	0	0	0	0	0	0	1	0	0	0	0	0	2018	

Data Base for SMITH 3 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR
6811	168	535.52	288045	0	0	0	0	0	0	1	0	0	0	0	0	2018
6552	168	529.67	282107	0	0	0	0	0	0	1	0	0	0	0	0	2018
6842	168	517.51	272976	0	0	0	0	0	0	0	1	0	0	0	0	2018
7150	168	523.55	277443	0	0	0	0	0	0	0	1	0	0	0	0	2018
7210	168	515.04	268828	0	0	0	0	0	0	0	1	0	0	0	0	2018
7139	168	539.03	291964	0	0	0	0	0	0	0	0	1	0	0	0	2018
7243	168	521.53	276367	0	0	0	0	0	0	0	0	1	0	0	0	2018
6947	168	512.99	270236	0	0	0	0	0	0	0	0	1	0	0	0	2018
6684	168	516.04	273503	0	0	0	0	0	0	0	0	1	0	0	0	2018
6817	168	540.78	293019	0	0	0	0	0	0	0	0	0	1	0	0	2018
6888	65	543.03	126132	0	0	0	0	0	0	0	0	0	1	0	0	2018
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2018
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2018
7421	165	239.76	58592	0	0	0	0	0	0	0	0	0	0	1	0	2018
7324	168	446.08	215083	0	0	0	0	0	0	0	0	0	0	1	0	2018
7343	168	471.88	229560	0	0	0	0	0	0	0	0	0	0	1	0	2018
7314	168	517.98	277988	0	0	0	0	0	0	0	0	0	0	1	0	2018
6774	168	495.83	258993	0	0	0	0	0	0	0	0	0	0	0	0	2018
6779	168	520.73	283060	0	0	0	0	0	0	0	0	0	0	0	0	2018
6806	168	391.77	175719	0	0	0	0	0	0	0	0	0	0	0	0	2018
6808	168	426.10	195164	0	0	0	0	0	0	0	0	0	0	0	0	2018
6742	168	467.62	230144	1	0	0	0	0	0	0	0	0	0	0	0	2019
6710	168	540.54	296323	1	0	0	0	0	0	0	0	0	0	0	0	2019
6721	168	488.64	258124	1	0	0	0	0	0	0	0	0	0	0	0	2019
6800	168	447.93	218756	1	0	0	0	0	0	0	0	0	0	0	0	2019
6722	168	498.26	256842	0	1	0	0	0	0	0	0	0	0	0	0	2019
6682	168	539.41	292640	0	1	0	0	0	0	0	0	0	0	0	0	2019
6664	168	533.75	285758	0	1	0	0	0	0	0	0	0	0	0	0	2019
6503	168	536.90	288843	0	1	0	0	0	0	0	0	0	0	0	0	2019
6900	168	500.96	258935	0	0	1	0	0	0	0	0	0	0	0	0	2019
6938	167	537.62	292201	0	0	1	0	0	0	0	0	0	0	0	0	2019
6927	168	526.58	279423	0	0	1	0	0	0	0	0	0	0	0	0	2019
7060	168	351.72	142988	0	0	1	0	0	0	0	0	0	0	0	0	2019
6887	168	264.48	70088	0	0	1	0	0	0	0	0	0	0	0	0	2019
6753	168	259.50	67394	0	0	0	1	0	0	0	0	0	0	0	0	2019
6821	168	254.39	64759	0	0	0	1	0	0	0	0	0	0	0	0	2019
6709	168	256.08	65677	0	0	0	1	0	0	0	0	0	0	0	0	2019
6499	168	256.29	65715	0	0	0	1	0	0	0	0	0	0	0	0	2019
6720	168	249.24	62155	0	0	0	0	1	0	0	0	0	0	0	0	2019
6850	168	247.01	61040	0	0	0	0	1	0	0	0	0	0	0	0	2019
6886	25	232.48	8724	0	0	0	0	1	0	0	0	0	0	0	0	2019
6945	112	259.96	56770	0	0	0	0	1	0	0	0	0	0	0	1	2019
6553	168	285.54	81989	0	0	0	0	1	0	0	0	0	0	0	0	2019
6612	168	294.92	87372	0	0	0	0	0	1	0	0	0	0	0	0	2019
6625	168	279.00	78630	0	0	0	0	0	1	0	0	0	0	0	0	2019
6608	168	289.74	84134	0	0	0	0	0	1	0	0	0	0	0	0	2019
6613	111	282.95	68100	0	0	0	0	0	1	0	0	0	0	0	1	2019
6631	168	288.92	83594	0	0	0	0	0	0	1	0	0	0	0	0	2019
6823	168	429.02	210635	0	0	0	0	0	0	1	0	0	0	0	0	2019
6838	145	460.12	250207	0	0	0	0	0	0	1	0	0	0	0	0	2019
6722	168	606.55	372048	0	0	0	0	0	0	1	0	0	0	0	0	2019
6721	168	614.06	378779	0	0	0	0	0	0	0	1	0	0	0	0	2019
6699	168	619.28	384595	0	0	0	0	0	0	0	1	0	0	0	0	2019

Data Base for SMITH 3 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR
6736	168	617.06	382580	0	0	0	0	0	0	0	1	0	0	0	0	2019
6756	168	619.38	384861	0	0	0	0	0	0	0	1	0	0	0	0	2019
6719	168	566.39	332306	0	0	0	0	0	0	0	1	0	0	0	0	2019
6801	168	593.71	359947	0	0	0	0	0	0	0	0	1	0	0	0	2019
6727	168	602.52	365461	0	0	0	0	0	0	0	0	1	0	0	0	2019
6754	168	605.93	368633	0	0	0	0	0	0	0	0	1	0	0	0	2019
6785	168	614.67	379087	0	0	0	0	0	0	0	0	1	0	0	0	2019
6664	168	629.62	396736	0	0	0	0	0	0	0	0	0	1	0	0	2019
6656	168	627.78	394308	0	0	0	0	0	0	0	0	0	1	0	0	2019
6582	168	618.48	383413	0	0	0	0	0	0	0	0	0	1	0	0	2019
6626	168	536.21	309341	0	0	0	0	0	0	0	0	0	1	0	0	2019
6759	101	586.37	218820	0	0	0	0	0	0	0	0	0	1	0	0	2019
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2019
6607	114	594.18	262565	0	0	0	0	0	0	0	0	0	0	1	1	2019
6562	168	583.67	344000	0	0	0	0	0	0	0	0	0	0	1	0	2019
6705	168	540.51	300166	0	0	0	0	0	0	0	0	0	0	1	0	2019
7029	168	621.60	387596	0	0	0	0	0	0	0	0	0	0	0	0	2019
7065	168	623.47	390113	0	0	0	0	0	0	0	0	0	0	0	0	2019
6976	168	589.25	356323	0	0	0	0	0	0	0	0	0	0	0	0	2019
7144	168	538.47	296370	0	0	0	0	0	0	0	0	0	0	0	0	2019
6985	168	590.79	352409	1	0	0	0	0	0	0	0	0	0	0	0	2020
7016	168	602.68	365430	1	0	0	0	0	0	0	0	0	0	0	0	2020
6999	168	607.44	372863	1	0	0	0	0	0	0	0	0	0	0	0	2020
6980	168	628.87	397155	1	0	0	0	0	0	0	0	0	0	0	0	2020
6952	168	625.32	392613	0	1	0	0	0	0	0	0	0	0	0	0	2020
6949	168	613.63	378768	0	1	0	0	0	0	0	0	0	0	0	0	2020
6947	168	595.48	359105	0	1	0	0	0	0	0	0	0	0	0	0	2020
6940	168	606.79	372322	0	1	0	0	0	0	0	0	0	0	0	0	2020
6995	72	495.33	115694	0	0	1	0	0	0	0	0	0	0	0	0	2020
6951	55	562.35	118128	0	0	1	0	0	0	0	0	0	0	0	1	2020
6974	168	619.76	385350	0	0	1	0	0	0	0	0	0	0	0	0	2020
7066	143	575.34	300149	0	0	1	0	0	0	0	0	0	0	0	1	2020
7017	168	598.54	360888	0	0	1	0	0	0	0	0	0	0	0	0	2020
7009	102	497.49	168728	0	0	0	1	0	0	0	0	0	0	0	1	2020
6976	168	592.95	354330	0	0	0	1	0	0	0	0	0	0	0	0	2020
6977	168	628.35	396028	0	0	0	1	0	0	0	0	0	0	0	0	2020
7005	168	577.32	340171	0	0	0	1	0	0	0	0	0	0	0	0	2020
7007	168	576.13	338141	0	0	0	0	1	0	0	0	0	0	0	0	2020
6958	168	592.76	354525	0	0	0	0	1	0	0	0	0	0	0	0	2020
7042	168	616.03	381696	0	0	0	0	1	0	0	0	0	0	0	0	2020
7043	168	581.03	346336	0	0	0	0	1	0	0	0	0	0	0	0	2020
7047	168	617.13	382468	0	0	0	0	1	0	0	0	0	0	0	0	2020
7106	168	623.71	390722	0	0	0	0	0	1	0	0	0	0	0	0	2020
7110	168	587.44	352097	0	0	0	0	0	1	0	0	0	0	0	0	2020
7080	168	594.49	363342	0	0	0	0	0	1	0	0	0	0	0	0	2020
7128	168	606.34	372045	0	0	0	0	0	1	0	0	0	0	0	0	2020

Data Base for SMITH 3 Target Heat Rate Equation

HtRt	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hr	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
J to N	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
YR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Calculation of
Target Average Net Operating Heat Rates
for January 2021 - December 2021

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKWH * 10^3 Generation	(5) Weighted ANOHR Target
SCHERER 3	Jan '21	401.7	183,109	11,086	113,268	
	Feb '21	254.4	74,084	11,911	1,018	
	Mar '21	0.0	0	-	0	
	Apr '21	0.0	0	-	0	
	May '21	288.3	94,992	11,647	100,341	
	Jun '21	337.3	129,633	11,660	220,601	
	Jul '21	363.1	149,973	11,380	266,495	
	Aug '21	404.6	185,729	11,075	258,118	
	Sep '21	349.1	138,756	11,300	155,356	
	Oct '21	0.0	0	-	0	
	Nov '21	0.0	0	-	0	
	Dec '21	366.7	152,926	11,222	85,064	11,339
CRIST 7	Jan '21	149.4	10,267	12,454	21,369	
	Feb '21	0.0	0	-	0	
	Mar '21	142.6	8,493	12,630	96,951	
	Apr '21	286.8	72,952	10,797	202,743	
	May '21	329.8	103,073	10,599	50,790	
	Jun '21	323.4	98,272	10,826	228,616	
	Jul '21	337.3	108,839	10,572	246,542	
	Aug '21	329.6	102,921	10,600	240,964	
	Sep '21	310.6	89,005	10,679	219,564	
	Oct '21	214.6	33,639	10,979	156,872	
	Nov '21	165.5	14,968	11,306	35,904	
	Dec '21	0.0	0	-	0	10,882

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on Page 2 of Schedule 1.

Column (5) = $(\Sigma ((3) * (4))) / (\Sigma (4))$

Calculation of
Target Average Net Operating Heat Rates
for January 2021 - December 2021

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKWH * 10^3 Generation	(5) Weighted ANOHR Target
DANIEL 1	Jan '21	368.2	139,076	10,031	76,590	
	Feb '21	0.0	0	-	0	
	Mar '21	239.5	56,213	11,464	163,345	
	Apr '21	221.0	47,325	10,992	74,246	
	May '21	238.0	55,464	10,807	142,814	
	Jun '21	287.3	82,695	10,558	165,776	
	Jul '21	317.5	102,042	10,239	162,257	
	Aug '21	309.0	96,392	10,283	175,192	
	Sep '21	275.3	75,570	10,492	13,488	
	Oct '21	0.0	0	-	0	
	Nov '21	141.9	17,895	11,845	17,451	
	Dec '21	283.3	80,285	10,437	27,196	10,650
DANIEL 2	Jan '21	331.8	123,311	10,300	231,258	
	Feb '21	311.9	108,326	10,371	187,141	
	Mar '21	304.4	102,929	10,092	128,140	
	Apr '21	341.6	131,047	10,459	117,153	
	May '21	270.2	80,064	10,578	64,848	
	Jun '21	347.6	135,899	10,252	241,910	
	Jul '21	368.4	153,400	10,200	264,844	
	Aug '21	359.2	145,529	10,222	258,258	
	Sep '21	347.9	136,144	10,251	223,003	
	Oct '21	283.5	88,616	10,502	193,055	
	Nov '21	274.2	82,591	10,554	151,898	
	Dec '21	275.1	83,165	10,549	178,544	10,334
SMITH 3	Jan '21	617.5	376,997	6,929	443,384	
	Feb '21	613.6	372,244	6,856	261,414	
	Mar '21	632.5	395,556	6,931	457,945	
	Apr '21	647.2	414,171	6,932	461,456	
	May '21	643.2	409,063	6,932	473,400	
	Jun '21	637.6	401,966	6,931	453,967	
	Jul '21	639.6	404,494	6,932	471,413	
	Aug '21	638.9	403,608	6,931	470,843	
	Sep '21	636.3	400,327	6,931	362,670	
	Oct '21	647.0	413,915	6,773	430,904	
	Nov '21	641.6	407,029	6,932	316,940	
	Dec '21	611.5	369,698	6,929	404,821	6,913

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on Page 2 of Schedule 1.

Column (5) = $(\Sigma \, ((3) * (4)) \,) / (\Sigma \, (4))$

Summary of Target, Maximum, and Minimum
Average Net Operating Heat Rates
for January 2021 - December 2021

Unit	Target Heat Rate BTU/KWH (0 Points)	Minimum Attainable Heat Rate (+ 10 Points)	Maximum Attainable Heat Rate (- 10 Points)
SCHERER 3	11,339	10,999	11,679
CRIST 7	10,882	10,556	11,208
DANIEL 1	10,650	10,331	10,970
DANIEL 2	10,334	10,024	10,644
SMITH 3	6,913	6,706	7,120

II. DETERMINATION OF EQUIVALENT AVAILABILITY TARGETS

Calculation of
Target Equivalent Availabilities
for January 2021 - December 2021

Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR *	Planned Outage Hours for Jan '21 - Dec '21	Reserve Shutdown Hours for Jan '21 - Dec '21	Target Equivalent Availability **
Scherer 3	0.0256	336	5,007	95.3
Crist 7	0.1478	0	2,288	89.0
Daniel 1	0.0848	1	4,443	93.9
Daniel 2	0.0855	0	1,223	93.4
Smith 3	0.0419	432	92	91.2

* For Period July 2015 through June 2020.

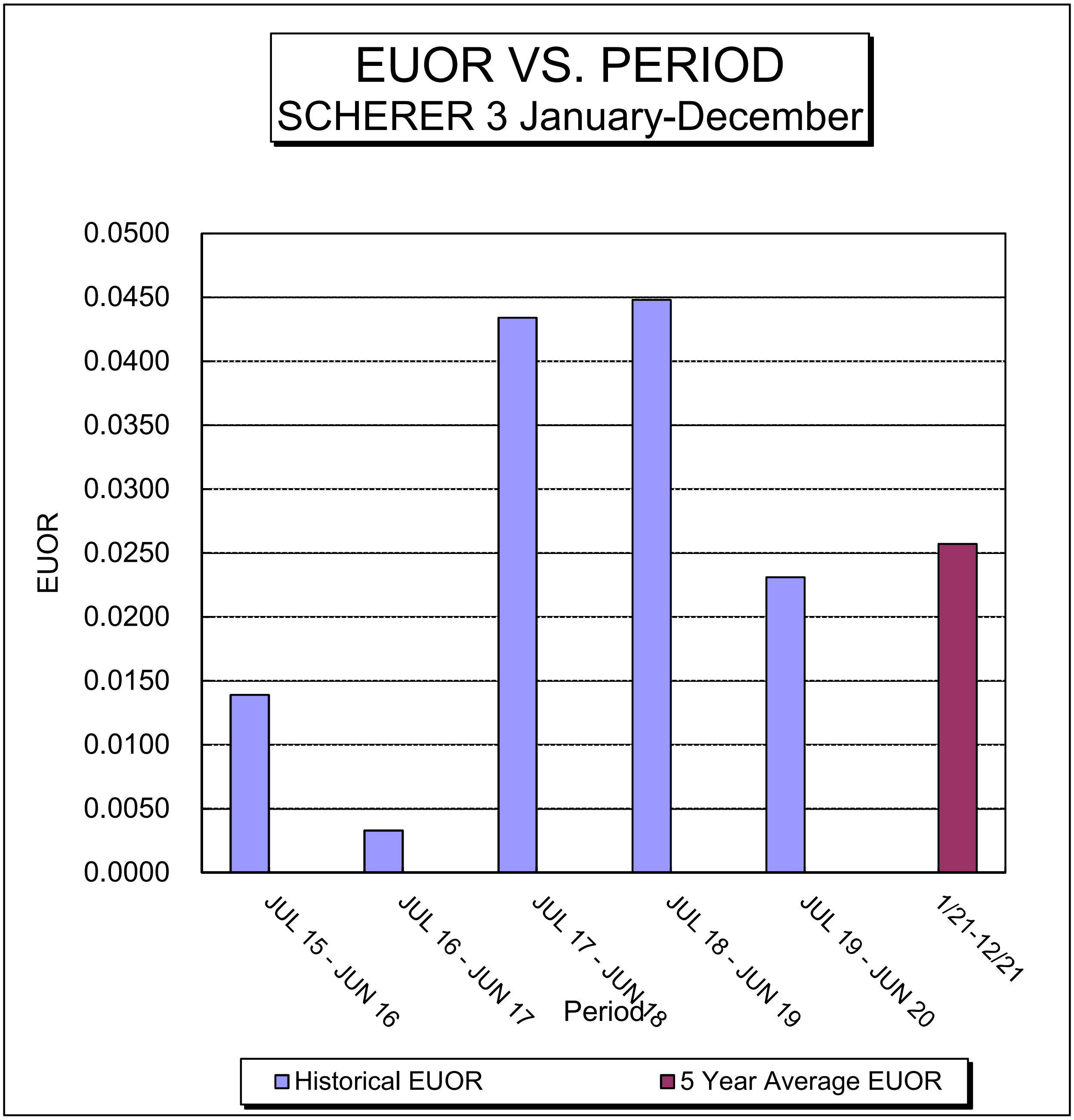
** EA = [1 - (POH + EUOR * (PH - POH - RSH)) / PH] * 100

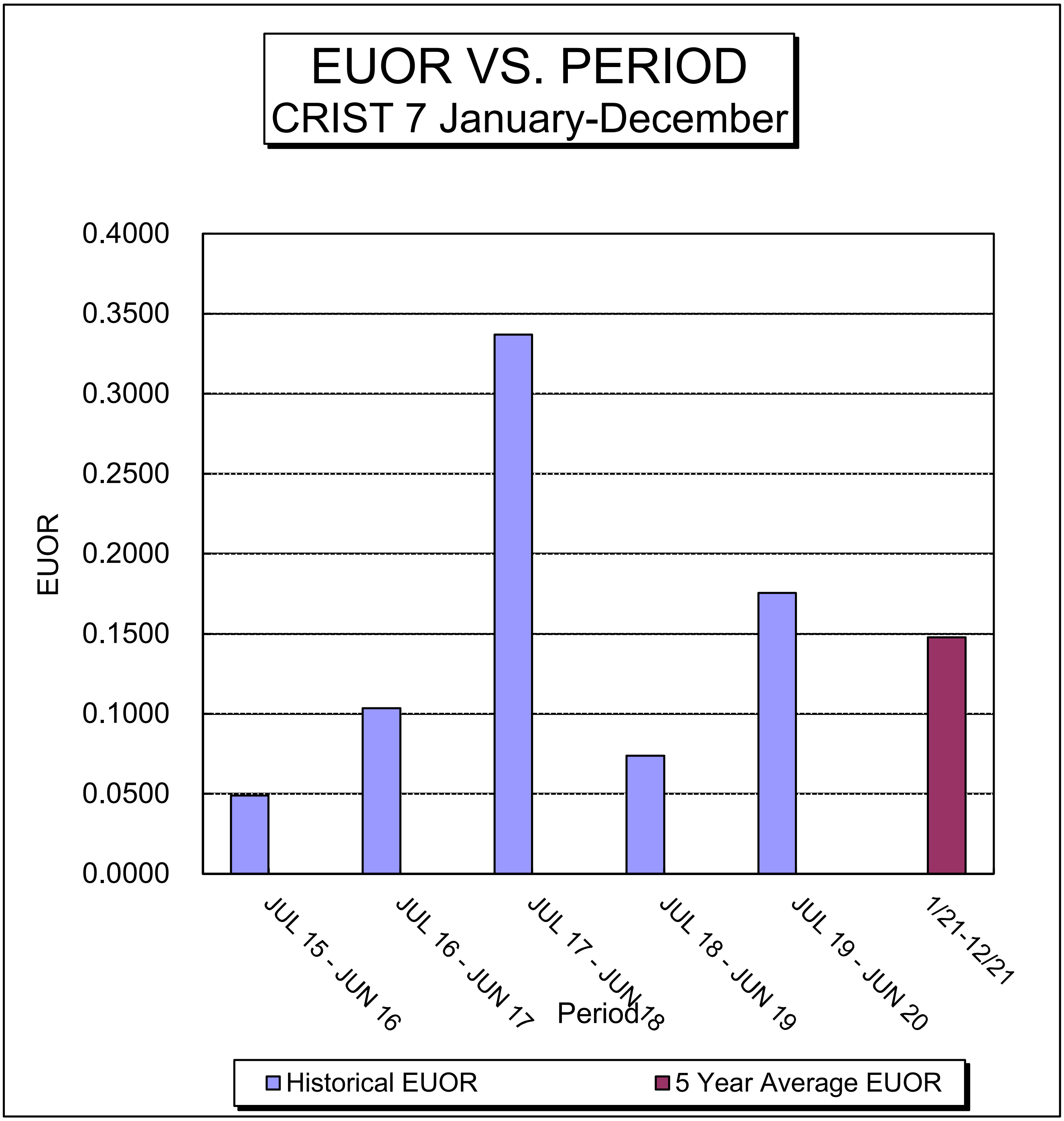
Calculation of Maximum and Minimum
Attainable Equivalent Availabilities
for January 2021 - December 2021

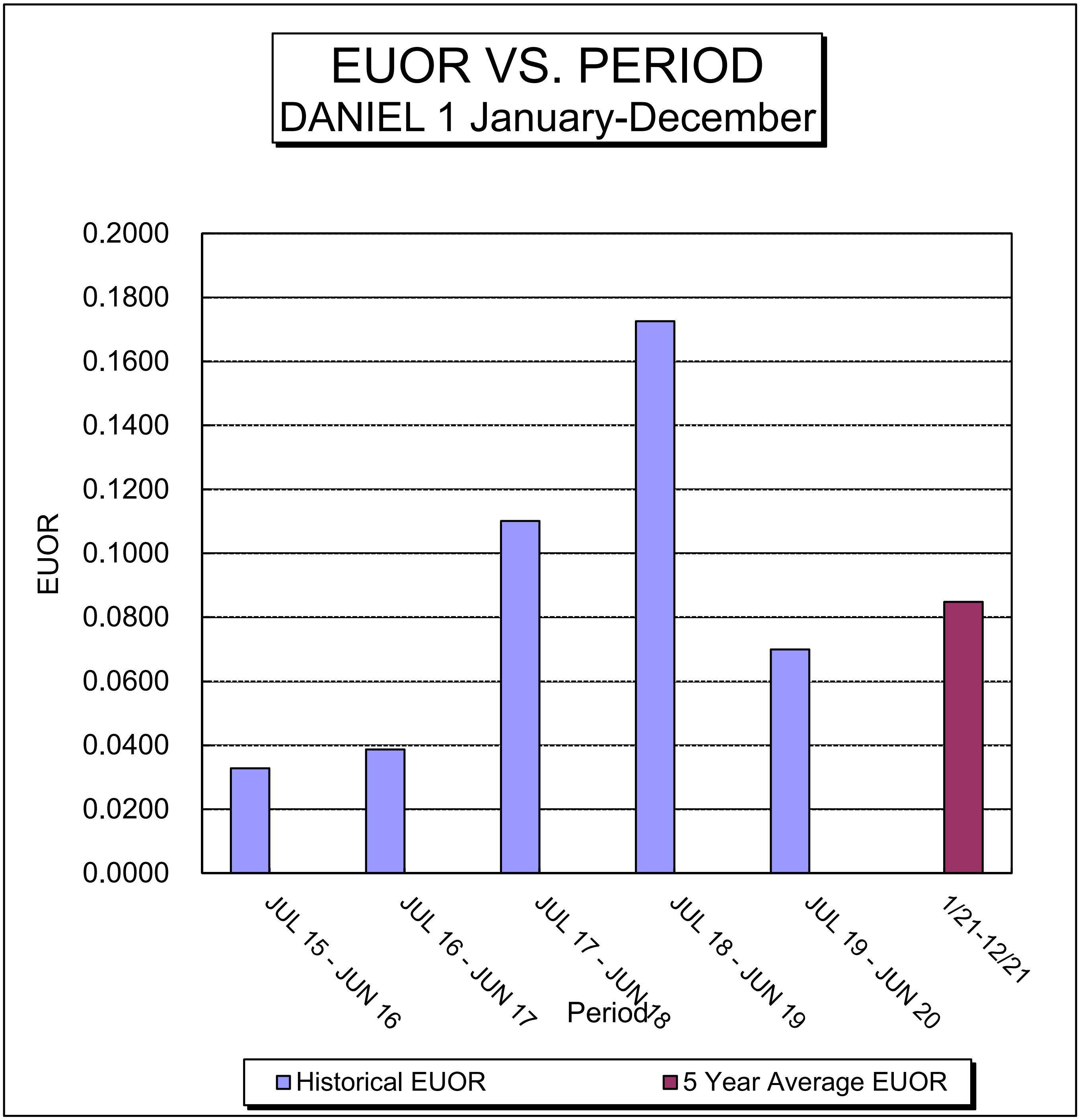
Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR (TARGET EUOR)	Minimum Attainable EUOR 70% of Target EUOR	Maximum Attainable Equivalent Availability	Maximum Attainable EUOR 145% of Target EUOR	Minimum Attainable Equivalent Availability
Scherer 3	0.0256	0.0179	95.5	0.0371	94.7
Crist 7	0.1478	0.1035	92.4	0.2143	84.2
Daniel 1	0.0848	0.0594	97.1	0.1230	93.9
Daniel 2	0.0855	0.0599	94.8	0.1240	89.3
Smith 3	0.0419	0.0293	92.3	0.0608	89.4

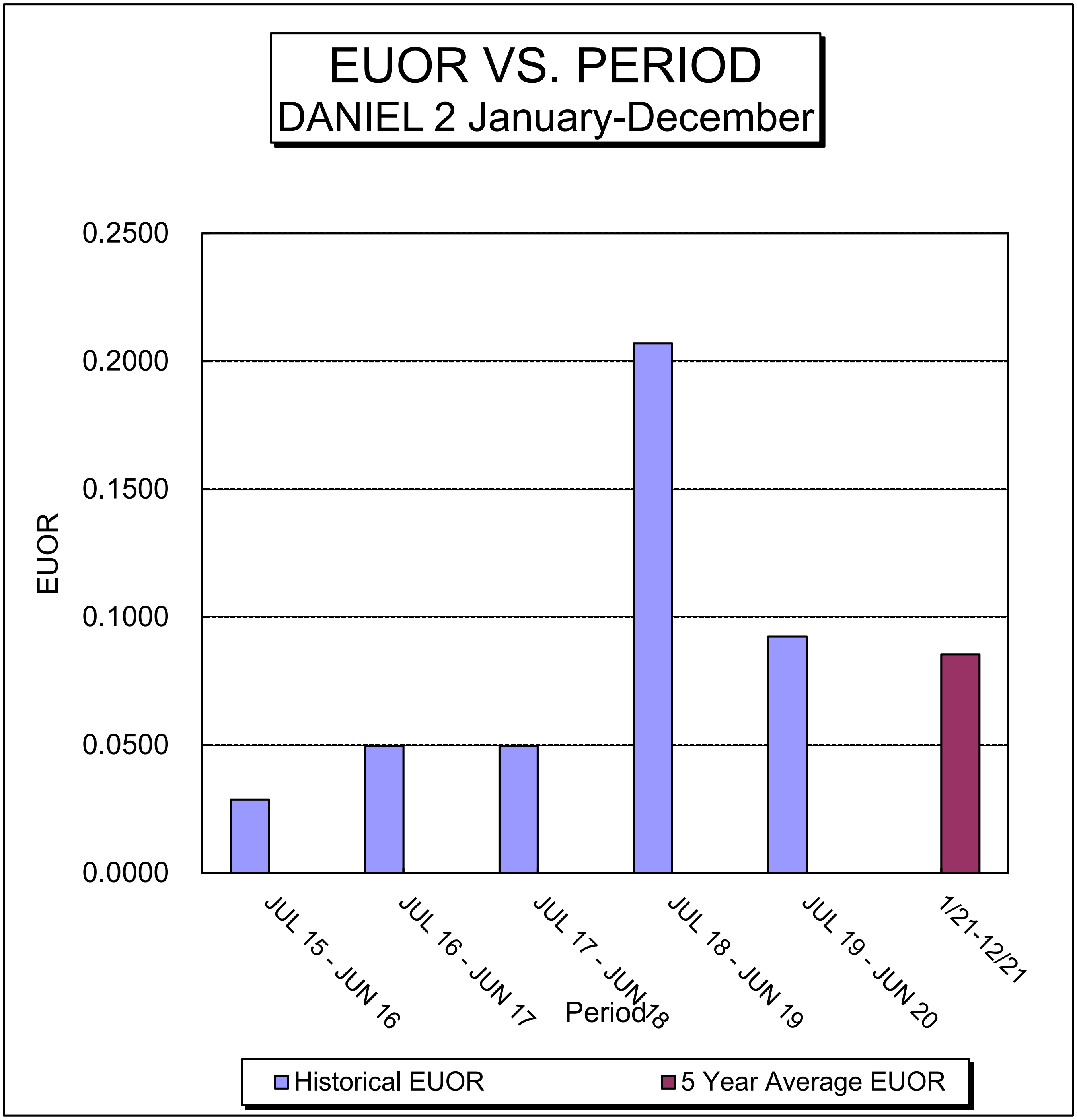
Summary of Target, Maximum, and Minimum
Equivalent Availabilities
for January 2021 - December 2021

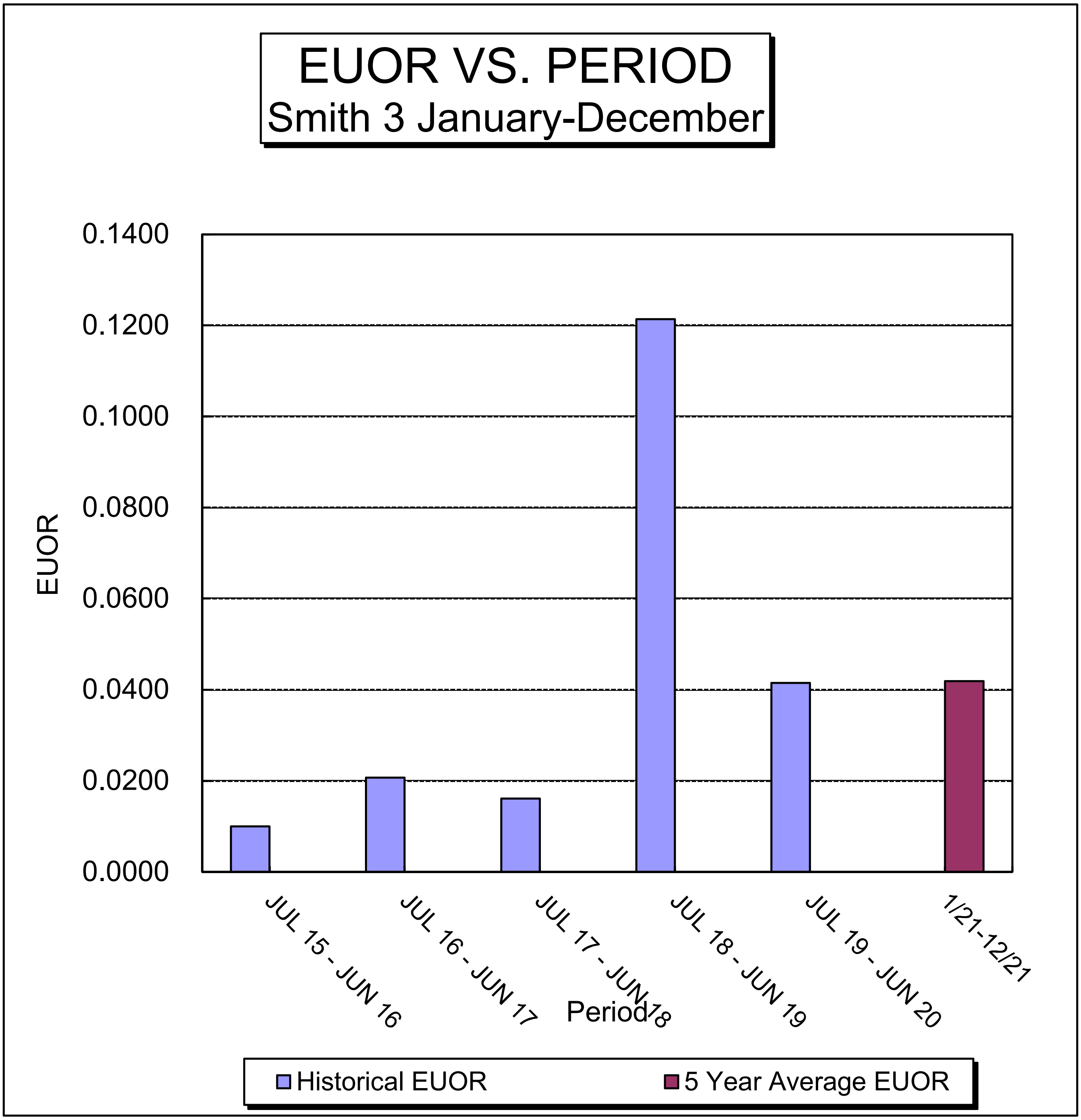
Unit	Target Equivalent Availability (0 Points)	Maximum Attainable Equivalent Availability (+10 Points)	Minimum Attainable Equivalent Availability (-10 Points)
Scherer 3	95.3	95.5	94.7
Crist 7	89.0	92.4	84.2
Daniel 1	93.9	97.1	93.9
Daniel 2	93.4	94.8	89.3
Smith 3	91.2	92.3	89.4


EUOR VS. PERIOD
SCHERER 3 January-December
EUOR
0.0500
0.0450
0.0400
0.0350
0.0300
0.0250
0.0200
0.0150
0.0100
0.0050
0.0000
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
JUL 18 - JUN 19
JUL 19 - JUN 20
1/21-12/21
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
CRIST 7 January-December
EUOR
0.4000
0.3500
0.3000
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
JUL 18 - JUN 19
JUL 19 - JUN 20
1/21-12/21
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 1 January-December
0.2000
0.1800
0.1600
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
JUL 18 - JUN 19
JUL 19 - JUN 20
1/21-12/21
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 2 January-December
EUOR
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
JUL 18 - JUN 19
JUL 19 - JUN 20
1/21-12/21
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
Smith 3 January-December
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
JUL 18 - JUN 19
JUL 19 - JUN 20
1/21-12/21
Period
Historical EUOR
5 Year Average EUOR

III. GPIF MINIMUM FILING REQUIREMENTS FOR THE PERIOD JANUARY 2021 - DECEMBER 2021

CONTENTS	SCHEDULE 3 PAGE

Generating Performance Incentive Factor

Estimated Reward/Penalty Table

Gulf Power Company

Period of: January 2021 - December 2021

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	4271	2136
+ 9	3844	1922
+ 8	3417	1708
+ 7	2990	1495
+ 6	2563	1281
+ 5	2136	1068
+ 4	1708	854
+ 3	1281	641
+ 2	854	427
+ 1	427	214
0	0	0
- 1	-430	-214
- 2	-860	-427
- 3	-1290	-641
- 4	-1720	-854
- 5	-2150	-1068
- 6	-2580	-1281
- 7	-3010	-1495
- 8	-3440	-1708
- 9	-3870	-1922
- 10	-4300	-2136
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Issued by: Gulf Power Company

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Estimated

Gulf Power Company

Period of: January 2021 - December 2021

Line 1	Beginning of Period Balance of Common Equity	$2,790,631,544
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '21	$2,748,152,095
Line 3	Month of Feb '21	$2,764,276,279
Line 4	Month of Mar '21	$2,778,194,006
Line 5	Month of Apr '21	$2,790,204,779
Line 6	Month of May '21	$2,810,899,869
Line 7	Month of Jun '21	$2,840,697,408
Line 8	Month of Jul '21	$2,873,271,411
Line 9	Month of Aug '21	$2,904,932,331
Line 10	Month of Sep '21	$2,990,254,157
Line 11	Month of Oct '21	$3,008,704,710
Line 12	Month of Nov '21	$3,023,707,815
Line 13	Month of Dec '21	$3,041,748,684
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$2,874,282,699
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	75.2353%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$9,550,978
Line 18	Jurisdictional Sales (KWH)	10,730,067,065
Line 19	Total Territorial Sales (KWH)	11,023,353,528
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	97.3394%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$9,296,865
Line 22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF point level from sheet 6.391.7)	$2,135,500
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF Pt. leve (The lesser of Line 21 and Line 22)	$2,135,500

Issued by: Gulf Power Company

GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2021 - December 2021

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Scherer 3	0.0%	95.3	95.5	94.7	$1	($4)
Crist 7	0.4%	89.0	92.4	84.2	$16	($20)
Daniel 1	0.0%	93.9	97.1	93.9	$1	($1)
Daniel 2	0.0%	93.4	94.8	89.3	$2	($5)
Smith 3	2.6%	91.2	92.3	89.4	$110	($129)

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Min BTU/KWH	ANOHR Range Max BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Scherer 3	1.3%	11,339	41.6	10,999	11,679	$57	($57)
Crist 7	12.2%	10,882	57.3	10,556	11,208	$519	($519)
Daniel 1	1.1%	10,650	54.1	10,331	10,970	$45	($45)
Daniel 2	4.8%	10,334	64.1	10,024	10,644	$205	($205)
Smith 3	77.6%	6,913	95.9	6,706	7,120	$3,315	($3,315)

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2021 - December 2021

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Target POF	Target EUOF	Target EUOR	Actual Performance 1st Prior Period Jul '19 - Jun '20 POF	EUOF	EUOR	Actual Performance 2nd Prior Period Jul '18 - Jun '19 POF	EUOF	EUOR
Scherer 3	0.0%	0.8%	0.0384	0.0090	0.0256	0.1869	0.0363	0.0448	0.0000	0.0421	0.0434
Crist 7	0.4%	12.3%	0.0000	0.1100	0.1478	0.0417	0.0659	0.0739	0.1794	0.2710	0.3370
Daniel 1	0.0%	0.8%	0.0001	0.0647	0.0848	0.0000	0.1245	0.1726	0.1545	0.0802	0.1101
Daniel 2	0.0%	1.5%	0.0000	0.0659	0.0855	0.0000	0.1722	0.2070	0.0247	0.0353	0.0498
Smith 3	2.6%	84.6%	0.0493	0.0389	0.0419	0.0230	0.1183	0.1214	0.0499	0.0153	0.0161
Weighted GPIF System Average:			0.0420	0.0480	0.0558	0.0260	0.1121	0.1167	0.0659	0.0478	0.0570

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2021 - December 2021

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Actual Performance 3rd Prior Period Jul '17 - Jun '18			Actual Performance 4th Prior Period Jul '16 - Jun '17			Actual Performance 5th Prior Period Jul '15 - Jun '16		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Scherer 3	0.0%	0.8%	0.1499	0.0024	0.0033	0.0000	0.0120	0.0139	0.1589	0.0550	0.0654
Crist 7	0.4%	12.3%	0.2417	0.0785	0.1036	0.1133	0.0322	0.0490	0.1938	0.0363	0.0453
Daniel 1	0.0%	0.8%	0.0372	0.0315	0.0387	0.0124	0.0135	0.0328	0.2231	0.0185	0.0324
Daniel 2	0.0%	1.5%	0.2074	0.0280	0.0497	0.0102	0.0153	0.0287	0.0495	0.0335	0.0480
Smith 3	2.6%	84.6%	0.1704	0.0171	0.0207	0.0583	0.0090	0.0100	0.0614	0.0182	0.0198
Weighted GPIF System Average:			0.1786	0.0248	0.0314	0.0635	0.0120	0.0153	0.0795	0.0209	0.0238

Issued by: Gulf Power Company

Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Average Net Operating Heat Rate

Gulf Power Company

Period of: January 2021 - December 2021

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Heat Rate Target	1st Prior Period Heat Rate Jul '19 - Jun '20	2nd Prior Period Heat Rate Jul '18 - Jun '19	3rd Prior Period Heat Rate Jul '17 - Jun '18
Scherer 3	1.3%	1.4%	11,339	11,631	11,331	11,296
Crist 7	12.2%	12.5%	10,882	11,406	10,800	10,857
Daniel 1	1.1%	1.1%	10,650	10,617	10,548	10,716
Daniel 2	4.8%	5.0%	10,334	10,729	10,459	10,333
Smith 3	77.6%	80.1%	6,913	6,984	6,886	6,960
Weighted GPIF System Average:			7,681	7,827	7,654	7,716

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Example Calculation of Prior Season

Average Net Operating Heat Rate

Adjusted to Target Basis

Crist 7 Jul '18 - Jun '19

	Jul Jan	Aug Feb	Sep Mar	Oct Apr	Nov May	Dec Jun	
1. Target Heat Rate*	10572.0 12454.0	10600.0 -	10679.0 12630.0	10979.0 10797.0	11306.0 10599.0	- 10826.0	
2. Target Heat Rate at Actual Conditions**	10585.0 10811.0	10586.0 10804.0	10455.0 10806.0	10274.0 10879.0	10141.0 10798.0	10703.0 11146.0	
3. Adjustments to Actual Heat Rate (1-2)	-13.0 1643.0	14.0 0.0	224.0 1824.0	705.0 -82.0	1165.0 -199.0	0.0 -320.0	
4. Actual Heat Rate for Prior Period	10440.0 10528.0	10314.0 10504.0	10749.0 10905.0	10182.0 10715.0	10343.0 10661.0	10791.0 10962.0	
5. Adjusted actual Heat Rate (4+3)	10427.0 12171.0	10328.0 10504.0	10973.0 12729.0	10887.0 10633.0	11508.0 10462.0	10791.0 10642.0	
6. Forecast Net MWH Generation*	246542.4 21368.9	240963.5 0.0	219564.3 96951.3	156871.6 202742.5	35904.3 50790.0	0.0 228616.2	
7. Adjusted Actual Heat Rate for Jul '18 - Jun '19 $= (\Sigma ((5) * (6))) / (\Sigma (6))$							10,800

* For the January 2021 - December 2021 time period.

** Based on the target heat rate equation from Page 2 of Schedule 1 using actual rather than forecast variable values.

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Derivation of Weighting Factors

Gulf Power Company

Period of: January 2021 - December 2021

Plant & Unit	Unit Performance Indicator	Production Cost Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Scherer 3	EA-3	$301,568	$301,567	$1	0.0%
Scherer 3	ANOHR-3	$301,568	$301,511	$57	1.3%
Crist 7	EA-4	$301,568	$301,552	$16	0.4%
Crist 7	ANOHR-4	$301,568	$301,049	$519	12.2%
Daniel 1	EA-5	$301,568	$301,567	$1	0.0%
Daniel 1	ANOHR-5	$301,568	$301,523	$45	1.1%
Daniel 2	EA-6	$301,568	$301,566	$2	0.0%
Daniel 2	ANOHR-6	$301,568	$301,363	$205	4.8%
Smith 3	EA-7	$301,568	$301,458	$110	2.6%
Smith 3	ANOHR-7	$301,568	$298,253	$3,315	77.6%

(1) Fuel Adjustment Base Case - All unit performance indicators at target.

(2) All other unit performance indicators at target.

(3) Expressed in replacement energy costs. Also includes variable operating and maintenance expense savings associated with availability improvements.

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2021 - December 2021

Scherer 3

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	1	95.50	+ 10	57	10,999
+ 9	1	95.47	+ 9	51	11,026
+ 8	1	95.44	+ 8	46	11,052
+ 7	1	95.41	+ 7	40	11,079
+ 6	1	95.38	+ 6	34	11,105
+ 5	1	95.35	+ 5	29	11,132
+ 4	0	95.32	+ 4	23	11,158
+ 3	0	95.29	+ 3	17	11,185
+ 2	0	95.26	+ 2	11	11,211
+ 1	0	95.23	+ 1	6	11,238
				0	11,264
0	0	95.20	0	0	11,339
				0	11,414
- 1	(0)	95.15	- 1	(6)	11,441
- 2	(1)	95.10	- 2	(11)	11,467
- 3	(1)	95.05	- 3	(17)	11,494
- 4	(2)	95.00	- 4	(23)	11,520
- 5	(2)	94.95	- 5	(29)	11,547
- 6	(2)	94.90	- 6	(34)	11,573
- 7	(3)	94.85	- 7	(40)	11,600
- 8	(3)	94.80	- 8	(46)	11,626
- 9	(4)	94.75	- 9	(51)	11,653
- 10	(4)	94.70	- 10	(57)	11,679
	Weighting Factor:	0.000		Weighting Factor:	0.013

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2021 - December 2021

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	16	92.40	+ 10	519	10,556
+ 9	14	92.07	+ 9	467	10,581
+ 8	13	91.74	+ 8	415	10,606
+ 7	11	91.41	+ 7	363	10,631
+ 6	10	91.08	+ 6	311	10,656
+ 5	8	90.75	+ 5	260	10,682
+ 4	6	90.42	+ 4	208	10,707
+ 3	5	90.09	+ 3	156	10,732
+ 2	3	89.76	+ 2	104	10,757
+ 1	2	89.43	+ 1	52	10,782
				0	10,807
0	0	89.10	0	0	10,882
				0	10,957
- 1	(2)	88.61	- 1	(52)	10,982
- 2	(4)	88.12	- 2	(104)	11,007
- 3	(6)	87.63	- 3	(156)	11,032
- 4	(8)	87.14	- 4	(208)	11,057
- 5	(10)	86.65	- 5	(260)	11,083
- 6	(12)	86.16	- 6	(311)	11,108
- 7	(14)	85.67	- 7	(363)	11,133
- 8	(16)	85.18	- 8	(415)	11,158
- 9	(18)	84.69	- 9	(467)	11,183
- 10	(20)	84.20	- 10	(519)	11,208

Weighting Factor: 0.004 Weighting Factor: 0.122

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2021 - December 2021

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	1	97.10	+ 10	45	10,331
+ 9	1	96.97	+ 9	41	10,355
+ 8	1	96.84	+ 8	36	10,380
+ 7	1	96.71	+ 7	32	10,404
+ 6	1	96.58	+ 6	27	10,429
+ 5	1	96.45	+ 5	23	10,453
+ 4	0	96.32	+ 4	18	10,477
+ 3	0	96.19	+ 3	14	10,502
+ 2	0	96.06	+ 2	9	10,526
+ 1	0	95.93	+ 1	5	10,551
				0	10,575
0	0	95.80	0	0	10,650
				0	10,725
- 1	(0)	95.61	- 1	(5)	10,750
- 2	(0)	95.42	- 2	(9)	10,774
- 3	(0)	95.23	- 3	(14)	10,799
- 4	(0)	95.04	- 4	(18)	10,823
- 5	(1)	94.85	- 5	(23)	10,848
- 6	(1)	94.66	- 6	(27)	10,872
- 7	(1)	94.47	- 7	(32)	10,897
- 8	(1)	94.28	- 8	(36)	10,921
- 9	(1)	94.09	- 9	(41)	10,946
- 10	(1)	93.90	- 10	(45)	10,970

Weighting Factor: 0.000 Weighting Factor: 0.011

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2021 - December 2021

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	2	94.80	+ 10	205	10,024
+ 9	2	94.58	+ 9	185	10,048
+ 8	2	94.36	+ 8	164	10,071
+ 7	1	94.14	+ 7	144	10,095
+ 6	1	93.92	+ 6	123	10,118
+ 5	1	93.70	+ 5	103	10,142
+ 4	1	93.48	+ 4	82	10,165
+ 3	1	93.26	+ 3	62	10,189
+ 2	0	93.04	+ 2	41	10,212
+ 1	0	92.82	+ 1	21	10,236
				0	10,259
0	0	92.60	0	0	10,334
				0	10,409
- 1	(1)	92.27	- 1	(21)	10,433
- 2	(1)	91.94	- 2	(41)	10,456
- 3	(2)	91.61	- 3	(62)	10,480
- 4	(2)	91.28	- 4	(82)	10,503
- 5	(3)	90.95	- 5	(103)	10,527
- 6	(3)	90.62	- 6	(123)	10,550
- 7	(4)	90.29	- 7	(144)	10,574
- 8	(4)	89.96	- 8	(164)	10,597
- 9	(5)	89.63	- 9	(185)	10,621
- 10	(5)	89.30	- 10	(205)	10,644

Weighting Factor: 0.000 Weighting Factor: 0.048

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2021 - December 2021

Smith 3

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	110	92.30	+ 10	3,315	6,706
+ 9	99	92.18	+ 9	2,984	6,719
+ 8	88	92.06	+ 8	2,652	6,732
+ 7	77	91.94	+ 7	2,321	6,746
+ 6	66	91.82	+ 6	1,989	6,759
+ 5	55	91.70	+ 5	1,658	6,772
+ 4	44	91.58	+ 4	1,326	6,785
+ 3	33	91.46	+ 3	995	6,798
+ 2	22	91.34	+ 2	663	6,812
+ 1	11	91.22	+ 1	332	6,825
				0	6,838
0	0	91.10	0	0	6,913
				0	6,988
- 1	(13)	90.93	- 1	(332)	7,001
- 2	(26)	90.76	- 2	(663)	7,014
- 3	(39)	90.59	- 3	(995)	7,028
- 4	(52)	90.42	- 4	(1,326)	7,041
- 5	(65)	90.25	- 5	(1,658)	7,054
- 6	(77)	90.08	- 6	(1,989)	7,067
- 7	(90)	89.91	- 7	(2,321)	7,080
- 8	(103)	89.74	- 8	(2,652)	7,094
- 9	(116)	89.57	- 9	(2,984)	7,107
- 10	(129)	89.40	- 10	(3,315)	7,120

Weighting Factor: 0.026 Weighting Factor: 0.776

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ESTIMATED UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2021 - December 2021

	SCHERER 3	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21	
1.	EAF (%)	99.6	99.6	61.0	93.1	99.6	99.6	
2.	POF (%)	0.0	0.0	38.8	6.7	0.0	0.0	
3.	EUOF (%)	0.4	0.4	0.2	0.2	0.4	0.4	
4.	EUOR (%)	1.1	42.9	100.0	100.0	0.9	0.5	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	282.0	4.0	0.0	0.0	348.0	654.0	
7.	RSH	459.0	665.0	453.0	670.0	393.0	63.0	
8.	UH	3.0	3.0	290.0	50.0	3.0	3.0	
9.	POH	0.0	0.0	288.0	48.0	0.0	0.0	
10.	FOH & EFOH	3.0	3.0	2.0	2.0	3.0	3.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	1255690	12120	0	0	1168673	2572205	
13.	Net Gen (MWH)	113268.1	1017.6	0.0	0.0	100341.1	220600.7	
14.	ANOHR (Btu/KWH)	11086.0	11911.0	-	-	11647.0	11660.0	
15.	NOF %	46.4	29.4	0.0	0.0	33.3	39.0	
16.	NPC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	
19.	ANOHR Equation	10^6 / AKW * [572.88 + 102.03 * JUN + 51.97 * JUL - 132.02 * NOV] + 9,659						

Issued by: Gulf Power Company

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2021 - December 2021

	SCHERER 3	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1.	EAF (%)	99.3	99.6	99.7	99.7	93.2	99.7	95.3
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	3.8
3.	EUOF (%)	0.7	0.4	0.3	0.3	6.8	0.3	0.9
4.	EUOR (%)	0.7	0.5	0.4	100.0	98.0	0.9	2.3
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	734.0	638.0	445.0	0.0	1.0	232.0	3338.0
7.	RSH	5.0	103.0	273.0	742.0	671.0	510.0	5007.0
8.	UH	5.0	3.0	2.0	2.0	49.0	2.0	415.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	336.0
10.	FOH & EFOH	5.0	3.0	2.0	2.0	1.0	2.0	31.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	48.0	0.0	48.0
12.	Oper MBtu	3032713	2858655	1755525	0	0	954583	13610164
13.	Net Gen (MWH)	266495.0	258117.8	155356.2	0.0	0.0	85063.5	1200260.0
14.	ANOHR (Btu/KWH)	11380.0	11075.0	11300.0	-	-	11222.0	11339.0
15.	NOF %	42.0	46.8	40.4	0.0	0.0	42.4	41.6
16.	NPC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	865.0
19.	ANOHR Equation	10^6 / AKW * [572.88 + 102.03 * JUN + 51.97 * JUL - 132.02 * NOV] + 9,659						

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2021 - December 2021

	CRIST 7	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21	
1.	EAF (%)	98.8	80.7	95.7	98.8	60.1	98.8	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	1.2	19.3	4.3	1.2	39.9	1.2	
4.	EUOR (%)	5.9	100.0	4.5	1.3	65.9	1.3	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	143.0	0.0	680.0	707.0	154.0	707.0	
7.	RSH	592.0	542.0	31.0	4.0	293.0	4.0	
8.	UH	9.0	130.0	32.0	9.0	297.0	9.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	9.0	9.0	9.0	9.0	9.0	9.0	
11.	MOH & EMOH	0.0	121.0	23.0	0.0	288.0	0.0	
12.	Oper MBtu	266128	0	1224495	2189011	538323	2474999	
13.	Net Gen (MWH)	21368.9	0.0	96951.3	202742.5	50790.0	228616.2	
14.	ANOHR (Btu/KWH)	12454.0	-	12630.0	10797.0	10599.0	10826.0	
15.	NOF %	31.5	0.0	30.0	60.4	69.4	68.1	
16.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	
19.	ANOHR Equation	10^6 / AKW * [583.75 + 65.07 * JUN - 83.65 * OCT - 131.30 * NOV] + 8,467						

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2021 - December 2021

	CRIST 7	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1.	EAF (%)	98.8	98.8	98.8	98.8	68.7	71.0	89.0
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	1.2	1.2	1.2	1.2	31.3	29.0	11.0
4.	EUOR (%)	1.2	1.2	1.3	1.2	51.0	100.0	14.9
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	731.0	731.0	707.0	731.0	217.0	0.0	5508.0
7.	RSH	4.0	4.0	4.0	4.0	278.0	528.0	2288.0
8.	UH	9.0	9.0	9.0	9.0	226.0	216.0	964.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	9.0	9.0	9.0	9.0	10.0	0.0	100.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	216.0	216.0	864.0
12.	Oper MBtu	2606446	2554213	2344727	1722293	405934	0	16326569
13.	Net Gen (MWH)	246542.4	240963.5	219564.3	156871.6	35904.3	0.0	1500314.9
14.	ANOHR (Btu/KWH)	10572.0	10600.0	10679.0	10979.0	11306.0	-	10882.0
15.	NOF %	71.0	69.4	65.4	45.2	34.8	0.0	57.3
16.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0
19.	ANOHR Equation	10^6 / AKW * [583.75 + 65.07 * JUN - 83.65 * OCT - 131.30 * NOV] + 8,467						

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2021 - December 2021

	DANIEL 1	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21	
1.	EAF (%)	98.4	100.0	98.5	98.5	98.5	98.5	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	1.6	0.0	1.5	1.5	1.5	1.5	
4.	EUOR (%)	5.5	0.0	1.6	3.2	1.8	1.9	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	208.0	0.0	682.0	336.0	600.0	577.0	
7.	RSH	524.0	672.0	50.0	373.0	133.0	132.0	
8.	UH	12.0	0.0	11.0	11.0	11.0	11.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	12.0	0.0	11.0	11.0	11.0	11.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	768278	0	1872588	816113	1543387	1750259	
13.	Net Gen (MWH)	76590.3	0.0	163345.1	74246.1	142813.7	165775.6	
14.	ANOHR (Btu/KWH)	10031.0	-	11464.0	10992.0	10807.0	10558.0	
15.	NOF %	73.4	0.0	47.7	44.0	47.4	57.2	
16.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	

19.	ANOHR Equation	10^6 / AKW * [647.40 - 165.06 * FEB + 160.81 * MAR + 42.47 * JUN - 38.44 * OCT - 94.68 * NOV] + 7,789 + 0.00128 * LSRF / AKW

Issued by: Gulf Power Company

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2021 - December 2021

	DANIEL 1	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1.	EAF (%)	98.5	98.5	58.5	77.4	98.3	98.5	93.9
2.	POF (%)	0.0	0.0	0.0	0.0	0.1	0.0	0.0
3.	EUOF (%)	1.5	1.5	41.5	22.6	1.6	1.5	6.5
4.	EUOR (%)	2.1	1.9	85.9	100.0	8.2	10.3	13.1
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	511.0	567.0	49.0	0.0	123.0	96.0	3749.0
7.	RSH	222.0	166.0	372.0	576.0	586.0	637.0	4443.0
8.	UH	11.0	11.0	299.0	168.0	12.0	11.0	568.0
9.	POH	0.0	0.0	0.0	0.0	1.0	0.0	1.0
10.	FOH & EFOH	11.0	11.0	11.0	0.0	11.0	11.0	111.0
11.	MOH & EMOH	0.0	0.0	288.0	168.0	0.0	0.0	456.0
12.	Oper MBtu	1661346	1801500	141521	0	206701	283848	10845541
13.	Net Gen (MWH)	162256.7	175192.0	13488.5	0.0	17450.5	27196.3	1018354.8
14.	ANOHR (Btu/KWH)	10239.0	10283.0	10492.0	-	11845.0	10437.0	10650.0
15.	NOF %	63.3	61.5	54.8	0.0	28.3	56.4	54.1
16.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0

19.	ANOHR Equation	10^6 / AKW * [647.40 - 165.06 * FEB + 160.81 * MAR + 42.47 * JUN - 38.44 * OCT - 94.68 * NOV] + 7,789 + 0.00128 * LSRF / AKW

Issued by: Gulf Power Company

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2021 - December 2021

	DANIEL 2	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21	
1.	EAF (%)	100.0	100.0	100.0	80.0	41.8	100.0	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	0.0	0.0	0.0	20.0	58.2	0.0	
4.	EUOR (%)	0.0	0.0	0.0	29.6	64.3	0.0	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	697.0	600.0	421.0	343.0	240.0	696.0	
7.	RSH	47.0	72.0	322.0	233.0	71.0	24.0	
8.	UH	0.0	0.0	0.0	144.0	433.0	0.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	0.0	0.0	0.0	0.0	217.0	0.0	
11.	MOH & EMOH	0.0	0.0	0.0	144.0	216.0	0.0	
12.	Oper MBtu	2381962	1940842	1293187	1225303	685958	2480063	
13.	Net Gen (MWH)	231258.4	187141.3	128139.8	117153.0	64847.6	241910.2	
14.	ANOHR (Btu/KWH)	10300.0	10371.0	10092.0	10459.0	10578.0	10252.0	
15.	NOF %	66.1	62.1	60.6	68.0	53.8	69.2	
16.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	
19.	ANOHR Equation	10^6 / AKW * [605.35 - 94.66 * MAR + 64.70 * APR] + 7,795 + 0.00183 * LSRF / AKW						

Issued by: Gulf Power Company

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2021 - December 2021

	DANIEL 2	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1.	EAF (%)	100.0	100.0	100.0	100.0	100.0	100.0	93.4
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	6.6
4.	EUOR (%)	0.0	0.0	0.0	0.0	0.0	0.0	7.7
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	719.0	719.0	641.0	681.0	554.0	649.0	6960.0
7.	RSH	25.0	25.0	79.0	63.0	167.0	95.0	1223.0
8.	UH	0.0	0.0	0.0	0.0	0.0	0.0	577.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	0.0	0.0	0.0	0.0	0.0	0.0	217.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	360.0
12.	Oper MBtu	2701412	2639917	2286001	2027467	1603130	1883456	23148698
13.	Net Gen (MWH)	264844.3	258258.4	223002.7	193055.3	151897.8	178543.6	2240052.4
14.	ANOHR (Btu/KWH)	10200.0	10222.0	10251.0	10502.0	10554.0	10549.0	10334.0
15.	NOF %	73.4	71.6	69.3	56.5	54.6	54.8	64.1
16.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0
19.	ANOHR Equation	10^6 / AKW * [605.35 - 94.66 * MAR + 64.70 * APR] + 7,795 + 0.00183 * LSRF / AKW						

Issued by: Gulf Power Company

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2021 - December 2021

	SMITH 3	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21	
1.	EAF (%)	97.4	65.3	100.0	100.0	100.0	100.0	
2.	POF (%)	0.0	32.1	0.0	0.0	0.0	0.0	
3.	EUOF (%)	2.6	2.6	0.0	0.0	0.0	0.0	
4.	EUOR (%)	2.6	3.8	0.0	0.0	0.0	0.0	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	718.0	426.0	724.0	713.0	736.0	712.0	
7.	RSH	7.0	13.0	19.0	7.0	8.0	8.0	
8.	UH	19.0	233.0	0.0	0.0	0.0	0.0	
9.	POH	0.0	216.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	19.0	17.0	0.0	0.0	0.0	0.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	3072208	1792254	3174016	3198813	3281609	3146442	
13.	Net Gen (MWH)	443384.1	261414.0	457944.9	461456.0	473400.0	453966.5	
14.	ANOHR (Btu/KWH)	6929.0	6856.0	6931.0	6932.0	6932.0	6931.0	
15.	NOF %	95.0	94.4	95.3	97.5	96.9	95.4	
16.	NPC (MW)	650.0	650.0	664.0	664.0	664.0	668.0	
19.	ANOHR Equation	10^6 / AKW * [-39.78 - 44.42 * FEB - 102.83 * OCT] + 6,994						

Issued by: Gulf Power Company

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2021 - December 2021

	SMITH 3	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1.	EAF (%)	99.7	100.0	80.0	90.3	69.2	89.1	91.2
2.	POF (%)	0.0	0.0	20.0	9.7	0.0	0.0	4.9
3.	EUOF (%)	0.3	0.0	0.0	0.0	30.8	10.9	3.9
4.	EUOR (%)	0.3	0.0	0.0	0.0	31.0	10.9	4.1
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	737.0	737.0	570.0	666.0	494.0	662.0	7895.0
7.	RSH	5.0	7.0	6.0	6.0	5.0	1.0	92.0
8.	UH	2.0	0.0	144.0	72.0	222.0	81.0	773.0
9.	POH	0.0	0.0	144.0	72.0	0.0	0.0	432.0
10.	FOH & EFOH	2.0	0.0	0.0	0.0	6.0	33.0	77.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	216.0	48.0	264.0
12.	Oper MBtu	3267835	3263413	2513666	2918513	2197028	2805004	34630801
13.	Net Gen (MWH)	471413.0	470843.0	362670.0	430904.0	316940.0	404820.9	5009156.4
14.	ANOHR (Btu/KWH)	6932.0	6931.0	6931.0	6773.0	6932.0	6929.0	6913.0
15.	NOF %	95.8	95.6	95.2	97.4	96.6	94.1	95.9
16.	NPC (MW)	668.0	668.0	668.0	664.0	664.0	650.0	661.8
19.	ANOHR Equation	10^6 / AKW * [-39.78 - 44.42 * FEB - 102.83 * OCT] + 6,994						

Issued by: Gulf Power Company

Planned Outage Schedules (Estimated)

Gulf Power Company

Period of: January 2021 - December 2021

Plant & Unit	Planned Outage Dates			Reason for Outage
Crist 7	03/07/20	-	04/26/20	
Smith 3	04/28/20	-	05/06/20	Borescope inspection
Smith 3	09/18/20	-	10/03/20	Borescope inspection
Daniel 1	03/24/20	-	04/01/20	
Daniel 1	09/26/20	-	12/11/20	
Daniel 2	04/10/20	-	05/17/20	

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Notes Regarding Estimated Planned Outage Schedules

Gulf Power Company

Period of: January 2021 - December 2021

It is important to understand that estimated dates for planned outages and their bar chart schedules are frequently changed in timing and work scope due to system conditions, findings of inspections, subcontractor requirements, material availability and so on.

Please note that in addition to the outages scheduled for the target period of January 2021 - December 2021, the outages shown below are currently planned and could be rescheduled for the target period.

Plant & Unit	Planned Outage Dates	Reason for Outage
	None	

DOCKET NO. 20200001-EI
2019 FINAL TRUE-UP FOR FUEL &
PURCHASED POWER AND CAPACITY
COST RECOVERY
EXHIBIT NO. _____ (MAS-1)

TAMPA ELECTRIC COMPANY

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI   EXHIBIT: 41
PARTY: TAMPA ELECTRIC COMPANY – DIRECT
DESCRIPTION: M. Ashley Sizemore MAS-1

FUEL AND PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY
INDEX

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 1

FINAL CAPACITY OVER/(UNDER)RECOVERY FOR

JANUARY 2019 – DECEMBER 2019

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

1.	Actual End-of-Period True-up: Over/(Under) Recovery	($2,067,989)
2.	Less: Actual/Estimated Over/(Under) Recovery Per Order No. PSC-2019-0484-FOF-EI For the January 2019 Through December 2019 Period	(2,179,217)
3.	Final True-up: Over/(Under) Recovery to Be Carried Forward to the January 2021 Through December 2021 Period	**$111,228**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	Total
1 UNIT POWER CAPACITY CHARGES	20,134	6,889	69,936	43,759	24,484	84,447	43,140	22,065	79,173	53,246	34,456	4,679	486,408
2 CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3 SCHEDULE J,D, & EMERG CAPACITY CHARGES	0	0	0	0	0	0	0	0	0	0	0	0	0
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0	0	0	0	0	0	0	0	0	0
5 (CAPACITY REVENUES)	(75,831)	(86,888)	(75,240)	(78,650)	(130,227)	(118,353)	(76,654)	(94,821)	(122,323)	(429,073)	(101,041)	(99,847)	(1,488,948)
6 TOTAL CAPACITY DOLLARS	(55,697)	(79,999)	(5,304)	(34,891)	(105,743)	(33,906)	(33,514)	(72,756)	(43,150)	(375,827)	(66,585)	(95,168)	(1,002,540)
7 JURISDICTIONAL PERCENTAGE	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
8 JURISDICTIONAL CAPACITY DOLLARS	(55,697)	(79,999)	(5,304)	(34,891)	(105,743)	(33,906)	(33,514)	(72,756)	(43,150)	(375,827)	(66,585)	(95,168)	(1,002,540)
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	1,240,565	1,244,911	1,212,875	(85,626)	(102,382)	(164,985)	(163,975)	(152,332)	(178,316)	(154,165)	(139,644)	(117,798)	2,439,128
10 PRIOR PERIOD TRUE-UP PROVISION	(232,082)	(232,082)	(232,082)	(128,947)	(128,947)	(128,947)	(128,947)	(128,947)	(128,947)	(128,947)	(128,947)	(128,951)	(1,856,773)
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	1,008,483	1,012,829	980,793	(214,573)	(231,329)	(293,932)	(292,922)	(281,279)	(307,263)	(283,112)	(268,591)	(246,749)	582,355
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	1,064,180	1,092,828	986,097	(179,682)	(125,586)	(260,026)	(259,408)	(208,523)	(264,113)	92,715	(202,006)	(151,581)	1,584,895
13 INTEREST PROVISION FOR PERIOD	(9,670)	(7,055)	(4,581)	(3,416)	(3,404)	(3,451)	(3,486)	(3,466)	(3,552)	(3,132)	(2,724)	(2,834)	(50,771)
14 OTHER ADJUSTMENT	0	0	0	0	0	0	0	0	0	0	0	0	0
15 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(5,458,886)	(4,172,294)	(2,854,439)	(1,640,841)	(1,694,992)	(1,695,035)	(1,829,565)	(1,963,512)	(2,046,554)	(2,185,272)	(1,966,742)	(2,042,525)	(5,458,886)
16 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	232,082	232,082	232,082	128,947	128,947	128,947	128,947	128,947	128,947	128,947	128,947	128,951	1,856,773
17 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	(4,172,294)	(2,854,439)	(1,640,841)	(1,694,992)	(1,695,035)	(1,829,565)	(1,963,512)	(2,046,554)	(2,185,272)	(1,966,742)	(2,042,525)	(2,067,989)	**(2,067,989)**

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	Total
1 BEGINNING TRUE-UP AMOUNT	(5,458,886)	(4,172,294)	(2,854,439)	(1,640,841)	(1,694,992)	(1,695,035)	(1,829,565)	(1,963,512)	(2,046,554)	(2,185,272)	(1,966,742)	(2,042,525)	(5,458,886)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(4,162,624)	(2,847,384)	(1,636,260)	(1,691,576)	(1,691,631)	(1,826,114)	(1,960,026)	(2,043,088)	(2,181,720)	(1,963,610)	(2,039,801)	(2,065,155)	(2,017,218)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(9,621,510)	(7,019,678)	(4,490,699)	(3,332,417)	(3,386,623)	(3,521,149)	(3,789,591)	(4,006,600)	(4,228,274)	(4,148,882)	(4,006,543)	(4,107,680)	(7,476,104)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(4,810,755)	(3,509,839)	(2,245,350)	(1,666,209)	(1,693,312)	(1,760,575)	(1,894,796)	(2,003,300)	(2,114,137)	(2,074,441)	(2,003,272)	(2,053,840)	(3,738,052)
5 INTEREST RATE % - 1ST DAY OF MONTH	2.420	2.410	2.410	2.480	2.430	2.390	2.320	2.100	2.050	1.970	1.660	1.600	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	2.410	2.410	2.480	2.430	2.390	2.320	2.100	2.050	1.970	1.660	1.600	1.710	NA
7 TOTAL (LINE 5 + LINE 6)	4.830	4.820	4.890	4.910	4.820	4.710	4.420	4.150	4.020	3.630	3.260	3.310	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	2.415	2.410	2.445	2.455	2.410	2.355	2.210	2.075	2.010	1.815	1.630	1.655	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.201	0.201	0.204	0.205	0.201	0.196	0.184	0.173	0.168	0.151	0.136	0.138	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(9,670)	(7,055)	(4,581)	(3,416)	(3,404)	(3,451)	(3,486)	(3,466)	(3,552)	(3,132)	(2,724)	(2,834)	(50,771)

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DOCKET NO. 20200001-EI
CCR 2019 FINAL TRUE-UP
EXHIBIT NO. _____ (MAS-1)
DOCUMENT NO. 1
PAGE 3 OF 4

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

		(1)	(2)	(3)	(4)
		ACTUAL	ACTUAL/ ESTIMATED	VARIANCE (1) - (2)	% CHANGE (3)/(2)
1	UNIT POWER CAPACITY CHARGES	$486,408	$249,648	$236,760	94.84%
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0.00%
3	SCHEDULE J & D CAPACITY CHARGES	0	0	0	0.00%
4	INCREMENTAL SECURITY O&M COSTS	0	0	0	0.00%
5	(CAPACITY REVENUES)	(1,488,948)	(1,130,376)	(358,572)	31.72%
6	TOTAL CAPACITY DOLLARS	($1,002,540)	($880,728)	($121,812)	13.83%
7	JURISDICTIONAL PERCENTAGE	100.00%	100.00%	0	0.00%
8	JURISDICTIONAL CAPACITY DOLLARS	($1,002,540)	(880,728)	($121,812)	13.83%
9	CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	2,439,128	2,456,085	(16,957)	-0.69%
10	PRIOR PERIOD TRUE-UP PROVISION	(1,856,773)	(1,856,773)	0	0.00%
11	CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	$582,355	$599,312	($16,957)	-2.83%
12	TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	$1,584,895	$1,480,040	$104,855	7.08%
13	INTEREST PROVISION FOR PERIOD	(50,771)	(57,144)	6,373	-11.15%
14	OTHER ADJUSTMENT	0	0	0	0.00%
15	TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(5,458,886)	(5,458,886)	0	0.00%
16	PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	1,856,773	1,856,773	0	0.00%
17	END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	($2,067,989)	($2,179,217)	$111,228	-5.10%

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 2

FINAL FUEL AND PURCHASED POWER OVER/(UNDER)RECOVERY

FOR

JANUARY 2019 – DECEMBER 2019

TAMPA ELECTRIC COMPANY
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2019 THROUGH DECEMBER 2019

1 TOTAL FUEL COSTS FOR THE PERIOD	$ 574,069,880
2 JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	574,069,880
3 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	583,210,492
4 ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD (LINE 3 - LINE 2)	$ 9,140,612
5 ADJUSTMENTS	0
6 INTEREST	(882,221)
7 TRUE-UP COLLECTED	33,791,590
8 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/18)	(36,970,912)
9 ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 4 + LINE 5 + LINE 6 + LINE 7 + LINE 8)	$ 5,079,072
10 PROJECTED OVER/(UNDER) RECOVERY PER PROJECTION FILED 9/3/19 (SCHEDULE E1-A LINE 6)	(30,742,026)
11 FINAL FUEL OVER/(UNDER) RECOVERY (LINE 9 - LINE 10)	**$ 35,821,098**

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 3

ACTUAL FUEL AND PURCHASED POWER TRUE-UP

VS.

ORIGINAL ESTIMATES

JANUARY 2019 – DECEMBER 2019

TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL vs. ORIGINAL ESTIMATES
FOR THE PERIOD
JANUARY 2019 THROUGH DECEMBER 2019

		ACTUAL	per Mid-Course ESTIMATED	VARIANCE AMOUNT	%
A	1. FUEL COST OF SYSTEM NET GENERATION	$525,783,664	$574,179,130	($48,395,466)	(8.4)
	2. FUEL COST OF POWER SOLD	3,427,702	724,525	2,703,177	373.1
	2a. GAINS FROM SALES	1,539,956	58,965	1,480,991	2,511.6
	3. FUEL COST OF PURCHASED POWER	347,608	0	347,608	0.0
	3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0
	3b. PAYMENT TO QUALIFIED FACILITIES	4,685,865	2,641,870	2,043,995	77.4
	4. ENERGY COST OF ECONOMY PURCHASES	43,757,439	32,887,040	10,870,399	33.1
	6a. ADJ. - BIG BEND UNITS 1-4 IGNITERS CONVERSION PROJECT	4,462,962	4,462,045	917	0.0
	6b. ADJ.	0	0	0	0.0
	6c. ADJ.	0	0	0	0.0
	7. ADJUSTED TOTAL FUEL & NET PWR.TRANS. (SUM OF LINES A1 THRU 6c)	$574,069,880	$613,386,595	($39,316,715)	(6.4)
C	1. JURISDICTIONAL FUEL REVENUE	$614,741,063	$605,688,614	$9,052,449	1.5
	2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0
	2a. TRUE-UP PROVISION	(33,791,590)	(33,791,590)	0	0.0
	2b. INCENTIVE PROVISION	2,261,019	2,261,019	0	0.0
	2c. ADJUSTMENT	0	0	0	0.0
	3. JURIS. FUEL REVENUE APPL. TO PERIOD (Sum of Lines C1 through C2c)	$583,210,492	$574,158,043	$9,052,449	1.6
	6d.JURISD. TOTAL FUEL & NET PWR. TRANS.	574,069,880	613,386,595	(39,316,715)	(6.4)
	7. TRUE-UP PROV.- THIS PER. (LINE C3-C6d)	$9,140,612	($39,228,552)	$48,369,164	(123.3)
	7a. ADJUSTMENTS	0	0	0	0.0
	8. INTEREST PROVISION - THIS PERIOD	(882,221)	(653,962)	(228,259)	34.9
	TOTAL TRUE-UP AMOUNT FOR PERIOD (LINE 7 through 8)	$8,258,391	($39,882,514)	$48,140,905	(120.7)
	9.TRUE-UP & INT. PROV. BEG. OF PERIOD (Beginning January 2019)	(36,970,912)	7,015,485	(43,986,397)	(627.0)
	10.TRUE-UP COLLECTED (REFUNDED)	33,791,590	33,791,590	0	0.0
	11.END OF PERIOD TOTAL NET TRUE-UP (LINE C8 through C10)	$5,079,072	$924,561	$4,154,511	449.3

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 4

FUEL AND PURCHASED POWER COST RECOVERY
YTD DECEMBER 2019

SCHEDULES A1 AND A2
AND
SCHEDULES A6 THROUGH A9
AND
SCHEDULE A12

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 AND A2

DECEMBER 2019

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: December 2019

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	38,938,646	44,322,631	(5,383,985)	-12.1%	1,441,903	1,528,830	(86,927)	-5.7%	2.70050	2.89912	(0.19862)	-6.9%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adjustments - Big Bend Units 1-4 Igniters Conversion Project	360,100	359,827	273	0.1%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments - Polk 1 Conversion Depreciation & ROI	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**39,298,746**	**44,682,458**	**(5,383,712)**	**-12.0%**	**1,441,903**	**1,528,830**	**(86,927)**	**-5.7%**	**2.72548**	**2.92266**	**(0.19718)**	**-6.7%**
6. Fuel Cost of Purchased Power - Firm (A7)	3,051	0	3,051	0.0%	140	0	140	0.0%	2.17929	0.00000	2.17929	0.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	386,875	1,008,830	(621,955)	-61.7%	4,653	25,490	(20,837)	-81.7%	8.31453	3.95775	4.35678	110.1%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities & Net Metering (A8)	245,117	194,890	50,227	25.8%	11,349	7,590	3,759	49.5%	2.15981	2.56772	(0.40791)	-15.9%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**635,043**	**1,203,720**	**(568,677)**	**-47.2%**	**16,142**	**33,080**	**(16,938)**	**-51.2%**	**3.93410**	**3.63881**	**0.29529**	**8.1%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,458,045**	**1,561,910**	**(103,865)**	**-6.6%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	70,402	16,130	54,272	336.5%	3,248	590	2,658	450.5%	2.16755	2.73390	(0.56635)	-20.7%
15. Fuel Cost of Sch. C/CB Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of OATT Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Market Base Sales (A6)	45,926	42,850	3,076	7.2%	2,141	1,200	941	78.4%	2.14507	3.57083	(1.42576)	-39.9%
18. Gains on Sales	16,319	5,099	11,220	220.0%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**132,647**	**64,079**	**68,568**	**107.0%**	**5,389**	**1,790**	**3,599**	**201.1%**	**2.46144**	**3.57983**	**(1.11839)**	**-31.2%**
20. Net Inadvertant Interchange					343	0	343	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					352	0	352	0.0%				
22. Interchange and Wheeling Losses					480	38	442	1156.3%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**39,801,142**	**45,822,099**	**(6,020,957)**	**-13.1%**	**1,452,871**	**1,560,082**	**(107,211)**	**-6.9%**	**2.73948**	**2.93716**	**(0.19768)**	**-6.7%**
24. Net Unbilled	(396,157) (a)	1,497,540 (a)	(1,893,697)	-126.5%	(14,461)	50,986	(65,447)	-128.4%	2.73949	2.93716	(0.19767)	-6.7%
25. Company Use	86,075 (a)	91,052 (a)	(4,977)	-5.5%	3,142	3,100	42	1.4%	2.73950	2.93716	(0.19766)	-6.7%
26. T & D Losses	2,352,119 (a)	1,601,627 (a)	750,492	46.9%	85,860	54,530	31,330	57.5%	2.73948	2.93716	(0.19768)	-6.7%
27. System KWH Sales	39,801,142	45,822,099	(6,020,957)	-13.1%	1,378,330	1,451,466	(73,136)	-5.0%	2.88764	3.15695	(0.26932)	-8.5%
28. Wholesale KWH Sales	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
29. Jurisdictional KWH Sales	39,801,142	45,822,099	(6,020,957)	-13.1%	1,378,330	1,451,466	(73,136)	-5.0%	2.88764	3.15695	(0.26932)	-8.5%
30. Jurisdictional Loss Multiplier									1.00000	1.00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	39,801,142	45,822,099	(6,020,957)	-13.1%	1,378,330	1,451,466	(73,136)	-5.0%	2.88764	3.15695	(0.26932)	-8.5%
32. Adjustment-BB Unit 2 Outage Replacement Power Cost T-up	0	0	0	0.0%	1,378,330	1,451,466	(73,136)	-5.0%	0.00000	0.00000	0.00000	0.0%
33. True-up *	3,949,494	3,949,494	0	0.0%	1,378,330	1,451,466	(73,136)	-5.0%	0.28654	0.27210	0.01444	5.3%
34. Total Jurisdictional Fuel Cost (Excl. GPIF)	43,750,636	49,771,593	(6,020,957)	-12.1%	1,378,330	1,451,466	(73,136)	-5.0%	3.17418	3.42906	(0.25488)	-7.4%
35. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
36. Fuel Cost Adjusted for Taxes (Excl. GPIF)	43,782,136	49,807,429	(6,025,293)	-12.1%	1,378,330	1,451,466	(73,136)	-5.0%	3.17646	3.43153	(0.25507)	-7.4%
37. GPIF * (Already Adjusted for Taxes)	(188,421)	(188,421)	0	0.0%	1,378,330	1,451,466	(73,136)	-5.0%	(0.01367)	(0.01298)	(0.00069)	5.3%
38. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**43,593,715**	**49,619,008**	**(6,025,293)**	**-12.1%**	**1,378,330**	**1,451,466**	**(73,136)**	**-5.0%**	**3.16279**	**3.41855**	**(0.25576)**	**-7.5%**
39. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.163**	**3.419**	**(0.256)**	**-7.5%**

* Based on Jurisdictional Sales (a) included for informational purposes only

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COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: December 2019

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	525,783,664	574,179,130	(48,395,466)	-8.4%	19,464,414	19,485,150	(20,736)	-0.1%	2.70126	2.94675	(0.24550)	-8.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adjustments - Big Bend Units 1-4 Igniters Conversion Project	4,462,962	4,462,045	917	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments - Polk 1 Conversion Depreciation & ROI	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**530,246,626**	**578,641,175**	**(48,394,549)**	**-8.4%**	**19,464,414**	**19,485,150**	**(20,736)**	**-0.1%**	**2.72418**	**2.96965**	**(0.24547)**	**-8.3%**
6. Fuel Cost of Purchased Power - Firm (A7)	347,608	0	347,608	0.0%	10,270	0	10,270	0.0%	3.38469	0.00000	3.38469	0.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	43,757,439	32,887,040	10,870,399	33.1%	1,234,844	894,370	340,474	38.1%	3.54356	3.67712	(0.13356)	-3.6%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities & Net Metering (A8)	4,685,865	2,641,870	2,043,995	77.4%	221,747	90,120	131,627	146.1%	2.11316	2.93150	(0.81834)	-27.9%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**48,790,912**	**35,528,910**	**13,262,002**	**37.3%**	**1,466,861**	**984,490**	**482,371**	**49.0%**	**3.32621**	**3.60886**	**(0.28265)**	**-7.8%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**20,931,275**	**20,469,640**	**461,635**	**2.3%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	646,314	271,470	374,844	138.1%	32,666	10,330	22,336	216.2%	1.97855	2.62798	(0.64942)	-24.7%
15. Fuel Cost of Sch. C/CB Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of OATT Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Market Base Sales (A6)	2,781,388	453,055	2,328,333	513.9%	122,535	11,990	110,545	922.0%	2.26987	3.77861	(1.50873)	-39.9%
18. Gains on Sales	1,539,956	58,965	1,480,991	2511.6%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES	**4,967,658**	**783,490**	**4,184,168**	**534.0%**	**155,201**	**22,320**	**132,881**	**595.3%**	**3.20079**	**3.51026**	**(0.30947)**	**-8.8%**
(LINE 14 + 15 + 16 + 17 + 18)												
20. Net Inadvertant Interchange					137	0	137	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					32,391	0	32,391	0.0%				
22. Interchange and Wheeling Losses					36,067	524	35,543	6781.0%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS	**574,069,880**	**613,386,595**	**(39,316,715)**	**-6.4%**	**20,772,535**	**20,446,796**	**325,739**	**1.6%**	**2.76360**	**2.99992**	**(0.23631)**	**-7.9%**
(LINE 5 + 12 - 19 + 20 + 21 - 22)												
24. Net Unbilled	(2,754,691) (a)	(583,069) (a)	(2,171,622)	372.4%	(73,907)	14,441	(88,348)	-611.8%	3.72724	(4.03759)	7.76483	-192.3%
25. Company Use	1,050,461 (a)	1,127,927 (a)	(77,466)	-6.9%	37,790	37,200	590	1.6%	2.77973	3.03206	(0.25233)	-8.3%
26. T & D Losses	28,267,619 (a)	27,654,738 (a)	612,881	2.2%	1,025,086	912,723	112,363	12.3%	2.75759	3.02992	(0.27233)	-9.0%
27. System KWH Sales	574,069,880	613,386,595	(39,316,715)	-6.4%	19,783,566	19,482,432	301,134	1.5%	2.90175	3.14841	(0.24666)	-7.8%
28. Wholesale KWH Sales	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
29. Jurisdictional KWH Sales	574,069,880	613,386,595	(39,316,715)	-6.4%	19,783,566	19,482,432	301,134	1.5%	2.90175	3.14841	(0.24666)	-7.8%
30. Jurisdictional Loss Multiplier									1.00000	1.00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	574,069,880	613,386,595	(39,316,715)	-6.4%	19,783,566	19,482,432	301,134	1.5%	2.90175	3.14841	(0.24666)	-7.8%
32. Adjustments - Schedule A2, page 2, lines 6c and 7a	0	0	0	0.0%	19,783,566	19,482,432	301,134	1.5%	0.00000	0.00000	0.00000	0.0%
33. True-up *	33,791,590	33,791,590	0	0.0%	19,783,566	19,482,432	301,134	1.5%	0.17081	0.17345	(0.00264)	-1.5%
34. Total Jurisdictional Fuel Cost (Excl. GPIF)	607,861,470	647,178,185	(39,316,715)	-6.1%	19,783,566	19,482,432	301,134	1.5%	3.07256	3.32186	(0.24930)	-7.5%
35. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
36. Fuel Cost Adjusted for Taxes (Excl. GPIF)	608,299,130	647,644,153	(39,345,023)	-6.1%	19,783,566	19,482,432	301,134	1.5%	3.07477	3.32425	(0.24948)	-7.5%
37. GPIF * (Already Adjusted for Taxes)	(2,261,019)	(2,261,019)	0	0.0%	19,783,566	19,482,432	301,134	1.5%	(0.01143)	(0.01161)	0.00018	-1.5%
38. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**606,038,111**	**645,383,134**	**(39,345,023)**	**-6.1%**	**19,783,566**	**19,482,432**	**301,134**	**1.5%**	**3.06334**	**3.31264**	**(0.24930)**	**-7.5%**
39. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.063**	**3.313**	**(0.250)**	**-7.5%**

* Based on Jurisdictional Sales (a) included for informational purposes only

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2019

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	38,938,646	44,322,631	(5,383,985)	-12.1%	525,783,664	574,179,130	(48,395,466)	-8.4%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	116,328	58,980	57,348	97.2%	3,427,702	724,525	2,703,177	373.1%
2a. GAINS FROM SALES	16,319	5,099	11,220	220.0%	1,539,956	58,965	1,480,991	2511.6%
3. FUEL COST OF PURCHASED POWER	3,051	0	3,051	0.0%	347,608	0	347,608	0.0%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	245,117	194,890	50,227	25.8%	4,685,865	2,641,870	2,043,995	77.4%
4. ENERGY COST OF ECONOMY PURCHASES	386,875	1,008,830	(621,955)	-61.7%	43,757,439	32,887,040	10,870,399	33.1%
5. TOTAL FUEL & NET POWER TRANSACTION	39,441,042	45,462,272	(6,021,230)	-13.2%	569,606,918	608,924,550	(39,317,632)	-6.5%
6a. ADJ. - BIG BEND UNITS 1-4 IGNITERS CONVERSION PROJECT	360,100	359,827	273	0.1%	4,462,962	4,462,045	917	0.0%
6b. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
6c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	39,801,142	45,822,099	(6,020,957)	-13.1%	574,069,880	613,386,595	(39,316,715)	-6.4%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,378,330	1,451,466	(73,136)	-5.0%	19,783,566	19,482,432	301,134	1.5%
2. NONJURISDICTIONAL SALES	0	0	0	0.0%	0	0	0	0.0%
3. TOTAL SALES	1,378,330	1,451,466	(73,136)	-5.0%	19,783,566	19,482,432	301,134	1.5%
4. JURISDIC. SALES-% TOTAL MWH SALES	1.0000000	1.0000000	0.0000000	0.0%	1.0000000	1.0000000	0.0000000	0.0%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2019

	CURRENT MONTH				PERIOD TO DATE			
			DIFFERENCE				DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	43,513,445	45,990,470	(2,477,025)	-5.4%	614,741,063	605,688,614	9,052,449	1.5%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(3,949,494)	(3,949,494)	0	0.0%	(33,791,590)	(33,791,590)	0	0.0%
2b. GPIF PROVISION	188,421	188,421	0	0.0%	2,261,019	2,261,019	0	0.0%
2c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	39,752,372	42,229,397	(2,477,025)	-5.9%	583,210,492	574,158,043	9,052,449	1.6%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	39,801,142	45,822,099	(6,020,957)	-13.1%	574,069,880	613,386,595	(39,316,715)	-6.4%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	1.0000000	1.0000000	0.0000000	0.0%	-	-	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	39,801,142	45,822,099	(6,020,957)	-13.1%	574,069,880	613,386,595	(39,316,715)	-6.4%
6a. JURISDIC. LOSS MULTIPLIER	1.00000	1.00000	0.00000	0.0%	-	-	-	-
6b. (LINE C6 x LINE C6a)	39,801,142	45,822,099	(6,020,957)	-13.1%	574,069,880	613,386,595	(39,316,715)	-6.4%
6c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
6d. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6c)	39,801,142	45,822,099	(6,020,957)	-13.1%	574,069,880	613,386,595	(39,316,715)	-6.4%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6d)	(48,770)	(3,592,702)	3,543,932	-98.6%	9,140,612	(39,228,552)	48,369,164	-123.3%
8. INTEREST PROVISION FOR THE MONTH	4,312	1,987	2,325	117.0%	(882,221)	(653,962)	(228,259)	34.9%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	1,174,036	565,782	608,254	107.5%	---NOT APPLICABLE---			
10. TRUE-UP COLLECTED (REFUNDED)	3,949,494	3,949,494	0	0.0%	---NOT APPLICABLE---			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	5,079,072	924,561	4,154,511	449.3%	---NOT APPLICABLE---			

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2019

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	1,174,036	565,782	608,254	107.5%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	5,074,760	922,574	4,152,186	450.1%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	6,248,796	1,488,356	4,760,440	319.8%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	3,124,398	744,178	2,380,220	319.8%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.600	3.200	(1.600)	-50.0%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.710	3.200	(1.490)	-46.6%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	3.310	6.400	(3.090)	-48.3%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.655	3.200	(1.545)	-48.3%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.138	0.267	(0.129)	-48.3%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	4,312	1,987	2,325	117.0%	NOT APPLICABLE			

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A6

JANUARY 2019 - DECEMBER 2019

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)	(9)
					CENTS/KWH				
SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED OTHER SYSTEM	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	TOTAL $ FOR TOTAL COST (5)X(6B)	GAINS ON MARKET BASED SALES
ESTIMATED:									
SEMINOLE	JURISD. SCH. - D	10,330.0	0.0	10,330.0	2.628	2.760	271,470.00	285,080.00	13,610.00
VARIOUS	JURISD. MKT.BASE	11,990.0	0.0	11,990.0	3.779	4.157	453,054.69	498,410.00	45,355.31
TOTAL		**22,320.0**	**0.0**	**22,320.0**	**3.246**	**3.510**	**724,524.69**	**783,490.00**	**58,965.31**
ACTUAL:									
SEMINOLE ELEC. PRECO-1	JURISD. SCH. - D	32,667.2	1.2	32,666.0	1.979	2.176	646,313.90	710,945.31	39,305.47
CITY OF LAKELAND	SCH. - MA	21,885.0	0.0	21,885.0	2.113	3.090	462,436.10	676,228.41	170,760.31
CITY OF LAKELAND	SCH. - MB	4,089.0	0.0	4,089.0	3.187	4.416	130,316.43	180,553.70	50,237.27
DUKE ENERGY FLORIDA	SCH. - MA	11,545.0	0.0	11,545.0	2.266	3.383	261,586.13	390,605.20	118,521.77
EDF TRADING	SCH. - MA	158.0	0.0	158.0	1.910	3.465	3,018.50	5,474.23	2,153.95
EXGEN	SCH. - MA	3,534.0	0.0	3,534.0	1.754	2.766	61,988.23	97,760.98	29,291.49
FLORIDA POWER & LIGHT	SCH. - MA	14,913.0	0.0	14,913.0	2.636	4.561	393,063.36	680,209.38	263,529.67
FMPA	SCH. - MA	3,220.0	0.0	3,220.0	2.649	4.975	85,285.00	160,181.61	72,544.61
MACQUARIE ENERGY LLC	SCH. - MA	8,134.0	0.0	8,134.0	2.065	3.263	167,981.65	265,425.15	88,449.82
MORGAN STANLEY	SCH. - MA	60.0	0.0	60.0	2.152	3.647	1,291.20	2,188.01	784.61
NEW SMYRNA BEACH	SCH. - MA	305.0	0.0	305.0	1.952	3.589	5,952.76	10,946.30	4,536.15
ORLANDO UTILITIES	SCH. - MA	27,556.0	0.0	27,556.0	2.185	3.535	601,962.02	974,109.09	320,535.16
REEDY CREEK	SCH. - MA	1.0	0.0	1.0	1.962	2.140	19.62	21.40	1.13
SEMINOLE ELECTRIC	SCH. - MA	7,200.0	0.0	7,200.0	1.933	3.406	139,200.00	245,263.25	93,031.25
SOUTHERN COMPANY	SCH. - MA	275.0	0.0	275.0	1.826	4.999	5,022.00	13,747.43	7,811.93
THE ENERGY AUTHORITY	SCH. - MA	19,660.0	0.0	19,660.0	2.351	3.853	462,263.65	757,500.59	278,464.81
LESS 20% - THRESHOLD EXCESS	SCH. - D								0.00
LESS 20% - THRESHOLD EXCESS	SCH. - C								0.00
LESS 20% - THRESHOLD EXCESS	SCH. - CB								0.00
LESS 20% - THRESHOLD EXCESS	SCH. - MA								0.00
SUB-TOTAL		**155,202.2**	**1.2**	**155,201.0**	**2.209**	**3.332**	**3,427,700.55**	**5,171,160.04**	**1,539,959.40**
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		32,667.2	1.2	32,666.0	1.979	2.176	646,313.90	710,945.31	39,305.47
SUB-TOTAL SCHEDULE C POWER SALES		0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE CB POWER SALES		0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE MA/MB POWER SALES-JURISD.		122,535.0	0.0	122,535.0	2.270	3.640	2,781,386.65	4,460,214.73	1,500,653.93
TOTAL		**155,202.2**	**1.2**	**155,201.0**	**2.209**	**3.332**	**3,427,700.55**	**5,171,160.04**	**1,539,959.40**
DIFFERENCE		132,882.2	1.2	132,881.0	(1.037)	(0.178)	2,703,175.86	4,387,670.04	1,480,994.09
DIFFERENCE %		595.4%	0.0%	595.3%	-31.9%	-5.1%	373.1%	560.0%	2511.6%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A7

JANUARY 2019 - DECEMBER 2019

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7) CENTS/KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FROM OTHER UTILITIES	MWH FOR INTER-RUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS		0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
ACTUAL:								
PASCO COGEN	SCH. - D *	0.0	0.0	0.0	0.0	0.000	0.000	103,799.73
DUKE ENERGY FLORIDA	EMERG A	124.0	0.0	0.0	124.0	19.671	19.671	24,392.04
ORLANDO UTIL. COMM.	EMERG A	100.0	0.0	0.0	100.0	5.635	5.635	5,635.00
DUKE ENERGY FLORIDA	OATT	10,046.0	0.0	0.0	10,046.0	2.128	2.128	213,781.69
SUB-TOTAL		**10,270.0**	**0.0**	**0.0**	**10,270.0**	**3.385**	**3.385**	**347,608.46**
SUB-TOTAL SCHEDULE D PURCHASED POWER		0.0	0.0	0.0	0.0	0.000	0.000	103,799.73
SUB-TOTAL SCHEDULE EMERG A PURCHASED POWER		224.0	0.0	0.0	224.0	13.405	13.405	30,027.04
SUB-TOTAL SCHEDULE OATT PURCHASED POWER		10,046.0	0.0	0.0	10,046.0	2.128	2.128	213,781.69
TOTAL		**10,270.0**	**0.0**	**0.0**	**10,270.0**	**3.385**	**3.385**	**347,608.46**
DIFFERENCE		10,270.0	0.0	0.0	10,270.0	3.385	3.385	347,608.46
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

* Includes adjustments to December 2018 and for the sale of back-up oil for Pasco Cogen

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A8

JANUARY 2019 - DECEMBER 2019

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ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
						CENTS/KWH		
	TYPE	TOTAL	MWH FROM	MWH FOR	MWH	(A)	(B)	TOTAL $ FOR FUEL
ESTIMATED:								
VARIOUS	**COGEN.**							
	AS AVAIL.	90,120.0	0.0	0.0	90,120.0	2.932	2.932	2,641,870.00
TOTAL		**90,120.0**	**0.0**	**0.0**	**90,120.0**	**2.932**	**2.932**	**2,641,870.00**
ACTUAL:	**AS AVAILABLE**							
McKAY BAY REFUSE	COGEN.	9.0	0.0	0.0	9.0	2.504	2.504	225.32
CARGILL RIDGEWOOD	COGEN.	11,196.0	0.0	0.0	11,196.0	2.184	2.184	244,513.76
CARGILL MILLPOINT	COGEN.	35,428.0	0.0	0.0	35,428.0	2.141	2.141	758,604.34
IMC-AGRICO-NEW WALES	COGEN.	2,743.0	0.0	0.0	2,743.0	2.525	2.525	69,259.22
IMC-AGRICO-S. PIERCE	COGEN.	170,709.0	0.0	0.0	170,709.0	2.092	2.092	3,571,294.72
SUB-TOTAL COGEN		**220,085.0**	**0.0**	**0.0**	**220,085.0**	**2.110**	**2.110**	**4,643,897.36**
NET METERING		**1,659.5**	**0.0**	**0.0**	**1,659.5**	**2.529**	**2.529**	**41,969.26**
TOTAL INCL NET METERING		**221,744.5**	**0.0**	**0.0**	**221,744.5**	**2.113**	**2.113**	**4,685,866.62**
DIFFERENCE		131,624.5	0.0	0.0	131,624.5	(0.818)	(0.818)	2,043,996.62
DIFFERENCE %		146.1%	0.0%	0.0%	146.1%	-27.9%	-27.9%	77.4%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A9

JANUARY 2019 - DECEMBER 2019

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) COST IF GENERATED		(9)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACTION COSTS	TOTAL $ FOR FUEL ADJUSTMENT (5) X (6)	(A) CENTS PER KWH	(B) TOTAL COST	FUEL SAVINGS (8B)-7
ESTIMATED:									
VARIOUS	Economy	894,370.0	0.0	894,370.0	3.677	32,887,040.00	4.358	38,976,438.00	6,089,398.00
TOTAL		**894,370.0**	**0.0**	**894,370.0**	**3.677**	**32,887,040.00**	**4.358**	**38,976,438.00**	**6,089,398.00**
ACTUAL:									
CITY OF LAKELAND	SCH. - J	330.0	0.0	330.0	3.900	12,870.00	3.900	12,870.00	0.00
CITY OF TALLAHASSEE	SCH. - J	2,740.0	0.0	2,740.0	1.264	34,630.00	2.174	59,557.50	24,927.50
DUKE ENERGY FLORIDA	SCH. - J	862,265.0	0.0	862,265.0	3.456	29,802,243.71	4.400	37,941,085.12	8,138,841.41
EDF TRADING	SCH. - J	1,825.0	0.0	1,825.0	5.574	101,730.00	6.422	117,199.50	15,469.50
EXGEN	SCH. - J	31,544.0	96.4	31,447.6	3.896	1,225,154.84	5.102	1,604,332.63	379,177.79
FLORIDA POWER & LIGHT	SCH. - J	88,433.0	47.4	88,385.6	4.281	3,783,721.15	4.857	4,293,136.70	509,415.55
FMPA	SCH. - J	185,070.0	0.0	185,070.0	2.994	5,541,618.05	3.427	6,342,462.85	800,844.80
MACQUARIE ENERGY LLC	SCH. - J	3,529.0	0.0	3,529.0	6.412	226,294.00	6.911	243,898.00	17,604.00
MORGAN STANLEY	SCH. - J	6,179.0	0.0	6,179.0	4.734	292,497.00	4.832	298,555.30	6,058.30
ORLANDO UTIL. COMM.	SCH. - J	17,152.0	0.0	17,152.0	4.918	843,525.00	5.833	1,000,487.15	156,962.15
RAINBOW ENERGY MARKETERS	SCH. - J	4,587.0	0.0	4,587.0	5.848	268,260.00	5.848	268,260.00	0.00
SOUTHERN COMPANY	SCH. - J	9,162.0	0.0	9,162.0	4.956	454,041.00	4.956	454,041.00	0.00
THE ENERGY AUTHORITY	SCH. - J	22,172.0	0.0	22,172.0	5.281	1,170,855.00	6.089	1,349,960.57	179,105.57
SUB-TOTAL		**1,234,988.0**	**143.8**	**1,234,844.2**	**3.544**	**43,757,439.75**	**4.372**	**53,985,846.32**	**10,228,406.57**
SUB-TOTAL SCHEDULE J ECONOMY PURCHASES		1,234,988.0	143.8	1,234,844.2	3.544	43,757,439.75	4.372	53,985,846.32	10,228,406.57
TOTAL		**1,234,988.0**	**143.8**	**1,234,844.2**	**3.544**	**43,757,439.75**	**4.372**	**53,985,846.32**	**10,228,406.57**
DIFFERENCE		340,618.0	143.8	340,474.2	(0.134)	10,870,399.75	0.014	15,009,408.32	4,139,008.57
DIFFERENCE %		38.1%	0.0%	38.1%	-3.6%	33.1%	0.3%	38.5%	68.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A12

JANUARY 2019 - DECEMBER 2019

REDACTED

REDACTED

38

CAPACITY COSTS
ACTUAL PURCHASES AND SALES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

CONTRACT	TERM START	TERM END	CONTRACT TYPE	
SEMINOLE ELECTRIC **	6/1/1992	-----------	LT	QF = QUALIFYING FACILITY LT = LONG TERM ST = SHORT-TERM ** THREE YEAR NOTICE REQUIRED FOR TERMINATION.

CONTRACT	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
SEMINOLE ELECTRIC	8.1	10.8	9.1	9.3	11.5	18.4	8.4	6.3	7.3	9.3	10.1	11.5

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
FLORIDA POWER & LIGHT	[redacted]												
DUKE ENERGY FLORIDA													
JACKSONVILLE ELECTRIC AUTHORITY													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
DUKE ENERGY FLORIDA - MA													
FLORIDA POWER & LIGHT - MA													
CITY OF LAKELAND - MA													
ORLANDO UTILITIES - MA													
EXGEN - MA													
REEDY CREEK - MA													
SEMINOLE ELECTRIC - MA													
THE ENERGY AUTHORITY - MA													
MACQUARIE ENERGY LLC - MA													
MORGAN STANLEY - MA													
SOUTHERN CO - MA													
FMPA - MA													
NEW SMYRNA BEACH - MA													
EDF TRADING - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	$ (55,697)	$ (79,999)	$ (5,304)	$ (34,891)	$ (105,743)	$ (33,906)	$ (33,514)	$ (72,756)	$ (43,150)	$ (375,827)	$ (66,585)	$ (95,168)	$ (1,002,540)
TOTAL CAPACITY	$ (55,697)	$ (79,999)	$ (5,304)	$ (34,891)	$ (105,743)	$ (33,906)	$ (33,514)	$ (72,756)	$ (43,150)	$ (375,827)	$ (66,585)	$ (95,168)	$ (1,002,540)

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 5

CAPITAL PROJECTS APPROVED FOR FUEL CLAUSE RECOVERY

JANUARY 2019 – DECEMBER 2019

BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1 BEGINNING BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348
2 ADD INVESTMENT: Big Bend Unit 3 (Jan 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2a ADD INVESTMENT: Big Bend Unit 4 (May 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2b ADD INVESTMENT: Big Bend Unit 2 (June 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2c ADD INVESTMENT: Big Bend Unit 1 (November 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
3 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4 ENDING BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348
5													
6													
7 AVERAGE BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	
8 DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9 DEPRECIATION EXPENSE	348,506	348,506	348,506	348,506	348,506	348,506	348,506	348,506	348,506	348,506	348,506	348,506	4,182,070
10 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11 BEGINNING BALANCE DEPRECIATION	15,095,780	15,444,286	15,792,792	16,141,297	16,489,803	16,838,309	17,186,815	17,535,321	17,883,826	18,232,332	18,580,838	18,929,344	15,095,780
12 ENDING BALANCE DEPRECIATION	$15,444,286	$15,792,792	$16,141,297	$16,489,803	$16,838,309	$17,186,815	$17,535,321	$17,883,826	$18,232,332	$18,580,838	$18,929,344	$19,277,850	$19,277,850
13													
14													
15 ENDING NET INVESTMENT	$5,466,062	$5,117,557	$4,769,051	$4,420,545	$4,072,039	$3,723,533	$3,375,028	$3,026,522	$2,678,016	$2,329,510	$1,981,004	$1,632,499	$1,632,499
16													
17													
18 AVERAGE INVESTMENT	$5,640,315	$5,291,809	$4,943,304	$4,594,798	$4,246,292	$3,897,786	$3,549,280	$3,200,775	$2,852,269	$2,503,763	$2,155,257	$1,806,751	
19 ALLOWED EQUITY RETURN	.36019%	.36019%	.36019%	.36019%	.36019%	.36019%	.37413%	.37413%	.37413%	.37413%	.37413%	.37413%	
20 EQUITY COMPONENT AFTER-TAX	20,316	19,061	17,805	16,550	15,295	14,040	13,279	11,975	10,671	9,367	8,064	6,760	163,183
21 CONVERSION TO PRE-TAX	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.32830	1.32830	1.32830	
22 EQUITY COMPONENT PRE-TAX	$27,283	$25,598	$23,911	$22,226	$20,540	$18,855	$17,833	$16,082	$14,331	$12,442	$10,711	$8,979	$218,791
23													
24 ALLOWED DEBT RETURN	.14287%	.14287%	.14287%	.14287%	.14287%	.14287%	.14474%	.14474%	.14474%	.14474%	.14474%	.14474%	
25 DEBT COMPONENT	$8,058	$7,560	$7,062	$6,564	$6,067	$5,569	$5,137	$4,633	$4,128	$3,624	$3,120	$2,615	$64,137
26 TAX REFORM TRUEUP										($2,038)			($2,038)
27 TOTAL RETURN REQUIREMENTS	$35,341	$33,158	$30,973	$28,790	$26,607	$24,424	$22,970	$20,715	$18,459	$14,028	$13,831	$11,594	$280,890
28 PRIOR MONTH TRUE-UP													
29 TOTAL DEPRECIATION & RETURN	$383,847	$381,664	$379,479	$377,296	$375,113	$372,930	$371,476	$369,221	$366,965	$362,534	$362,337	$360,100	$4,462,962
30													
31 ESTIMATED FUEL SAVINGS	$556,528	$515,586	$413,422	$695,832	$685,374	$495,625	$860,514	$473,271	$196,904	$384,980	$552,612	$426,533	$6,257,182
32 TOTAL DEPRECIATION & RETURN	$383,847	$381,664	$379,479	$377,296	$375,113	$372,930	$371,476	$369,221	$366,965	$362,534	$362,337	$360,100	$4,462,962
33 NET BENEFIT (COST) TO RATEPAYER	$172,681	$133,923	$33,943	$318,536	$310,261	$122,695	$489,039	$104,050	($170,061)	$22,446	$190,275	$66,433	$1,794,221

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - JUNE USING AN ANNUAL RATE OF 7.5190% (EQUITY 5.8046% , DEBT 1.7144%). RATES ARE BASED ON THE MAY 2018 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JULY - SEPTEMBER USING AN ANNUAL RATE OF 7.7662% (EQUITY 6.0293% , DEBT 1.7369%). RATES ARE BASED ON THE MAY 2019 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
37 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR OCTOBER - DECEMBER AND THE YEAR-TO-DATE TRUE UP FOR JULY - SEPTEMBER USING AN ANNUAL RATE OF 7.7004% (EQUITY 5.9635% , DEBT 1.7369%). RATES ARE BASED ON THE MAY 2019 SURVEILLANCE REPORT AND UPDATED TAX RATE PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012). TRUE UP FOR JANUARY - JUNE USING AN ANNUAL RATE OF 7.4557% (EQUITY 5.7413% , DEBT 1.7144%) BOOKED IN OCTOBER.
38 A RETROACTIVE CHANGE TO THE STATE TAX RATE LED TO A DECREASE IN THE TAX MULTIPLIER FROM 1.34295 TO 1.32830 AND A RESULTING YEAR-TO-DATE ROI TRUE-UP OF ($2,038) IN OCTOBER 2019
39 THE RETURN REQUIREMENT FOR JANUARY - SEPTEMBER IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 25.345%
40 THE RETURN REQUIREMENT FOR OCTOBER - DECEMBER AND THE YEAR-TO-DATE TRUE-UP IN OCTOBER IS CALCULATED BASED ON A COMBINED STATUTORY RATE OF 24.522%
41 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

40

DOCKET NO. 20200001-EI
FAC 2019 FINAL TRUE-UP
EXHIBIT NO. ____ (MAS-1)
DOCUMENT NO. 5
PAGE 1 OF 5

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
JANUARY 2019 to JUNE 2019
Prior to State Tax Reform

	(1) Jurisdictional Rate Base Actual May 2018 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,719,219	30.51%	5.13%	1.5652%
Short Term Debt	244,333	4.34%	2.18%	0.0945%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	96,005	1.70%	2.43%	0.0414%
Common Equity	2,367,502	42.02%	10.25%	4.3067%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,187,473	21.07%	0.00%	0.0000%
Deferred ITC - Weighted Cost	20,116	0.36%	8.10%	0.0289%
Total	$ 5,634,648	100.00%		6.04%

ITC split between Debt and Equity:

Long Term Debt	$ 1,719,219	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,367,502	Equity - Common	54.00%
Total	$ 4,086,721	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0289% * 46.00%	0.0133%
Equity = .0289% * 54.00%	0.0156%
Weighted Cost	0.0289%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3067%
Deferred ITC - Weighted Cost	0.0156%
	4.3223%
Times Tax Multiplier	1.34295
Total Equity Component	5.8046%

Total Debt Cost Rate:

Long Term Debt	1.5652%
Short Term Debt	0.0945%
Customer Deposits	0.0414%
Deferred ITC - Weighted Cost	0.0133%
Total Debt Component	1.7144%
	7.5190%

Notes:
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
July 2019 to December 2019
Prior to State Tax Reform

		(1) Jurisdictional Rate Base Actual May 2019 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$	1,897,597	31.57%	4.89%	1.5435%
Short Term Debt		211,895	3.52%	2.97%	0.1047%
Preferred Stock		0	0.00%	0.00%	0.0000%
Customer Deposits		94,966	1.58%	2.38%	0.0376%
Common Equity		2,598,065	43.22%	10.25%	4.4297%
Accum. Deferred Inc. Taxes & Zero Cost ITC's		1,125,550	18.72%	0.00%	0.0000%
Deferred ITC - Weighted Cost		83,633	1.39%	7.98%	0.1110%
Total	$	6,011,707	100.00%		6.23%

ITC split between Debt and Equity:

Long Term Debt	$	1,897,597	Long Term Debt	46.00%
Equity - Preferred		0	Equity - Preferred	0.00%
Equity - Common		2,598,065	Equity - Common	54.00%
Total	$	4,495,662	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.1110% * 46.00%	0.0511%
Equity = 0.1110% * 54.00%	0.0599%
Weighted Cost	0.1110%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4297%
Deferred ITC - Weighted Cost	0.0599%
	4.4896%
Times Tax Multiplier	1.34295
Total Equity Component	6.0293%

Total Debt Cost Rate:

Long Term Debt	1.5435%
Short Term Debt	0.1047%
Customer Deposits	0.0376%
Deferred ITC - Weighted Cost	0.0511%
Total Debt Component	1.7369%
	7.7662%

Notes:
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
JANUARY 2019 to JUNE 2019
Updated for State Tax Reform

	(1) Jurisdictional Rate Base Actual May 2018 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,719,219	30.51%	5.13%	1.5652%
Short Term Debt	244,333	4.34%	2.18%	0.0945%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	96,005	1.70%	2.43%	0.0414%
Common Equity	2,367,502	42.02%	10.25%	4.3067%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,187,473	21.07%	0.00%	0.0000%
Deferred ITC - Weighted Cost	20,116	0.36%	8.10%	0.0289%
Total	$ 5,634,648	100.00%		6.04%

ITC split between Debt and Equity:

Long Term Debt	$ 1,719,219	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,367,502	Equity - Common	54.00%
Total	$ 4,086,721	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0289% * 46.00%	0.0133%
Equity = .0289% * 54.00%	0.0156%
Weighted Cost	0.0289%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3067%
Deferred ITC - Weighted Cost	0.0156%
	4.3223%
Times Tax Multiplier	1.32830
Total Equity Component	5.7413%

Total Debt Cost Rate:

Long Term Debt	1.5652%
Short Term Debt	0.0945%
Customer Deposits	0.0414%
Deferred ITC - Weighted Cost	0.0133%
Total Debt Component	1.7144%
	7.4557%

Notes:

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Column (4) - Column (2) x Column (3)

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
July 2019 to December 2019
Updated for State Tax Reform

	(1) Jurisdictional Rate Base Actual May 2019 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,897,597	31.57%	4.89%	1.5435%
Short Term Debt	211,895	3.52%	2.97%	0.1047%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	94,966	1.58%	2.38%	0.0376%
Common Equity	2,598,065	43.22%	10.25%	4.4297%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,125,550	18.72%	0.00%	0.0000%
Deferred ITC - Weighted Cost	83,633	1.39%	7.98%	0.1110%
Total	$ 6,011,707	100.00%		6.23%

ITC split between Debt and Equity:

Long Term Debt	$ 1,897,597	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,598,065	Equity - Common	54.00%
Total	$ 4,495,662	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.1110% * 46.00%	0.0511%
Equity = 0.1110% * 54.00%	0.0599%
Weighted Cost	0.1110%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4297%
Deferred ITC - Weighted Cost	0.0599%
	4.4896%
Times Tax Multiplier	1.32830
Total Equity Component	5.9635%

Total Debt Cost Rate:

Long Term Debt	1.5435%
Short Term Debt	0.1047%
Customer Deposits	0.0376%
Deferred ITC - Weighted Cost	0.0511%
Total Debt Component	1.7369%
	7.7004%

Notes:
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 1

FUEL AND PURCHASED POWER COST RECOVERY

ACTUAL / ESTIMATED

JANUARY 2020 THROUGH DECEMBER 2020

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI   EXHIBIT: 42
PARTY: TAMPA ELECTRIC COMPANY – DIRECT
DESCRIPTION: M. Ashley Sizemore MAS-2

TAMPA ELECTRIC COMPANY

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TAMPA ELECTRIC COMPANY
CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2020 - December 2020 (6 months actual, 6 months estimated)	($43,367,307)
2.	PROJECTED OVER/UNDER-RECOVERY TRUE-UP INCLUDED IN JUNE - DECEMBER 2020 RATES (Per Mid-Course correction Schedule E1-C, line 1B)	$0
3.	DIFFERENCE IN 2019 ESTIMATED TRUE-UP AMOUNT PROJECTED IN ORIGINAL 2020 RATES AND AMOUNT COLLECTED IN 2020 ($30,742,026 under-recovery less ($2,561,836) refunded each month January through May 2020)	($17,932,846)
4.	ACTUAL-ESTIMATED 2020 OVER/(UNDER) RECOVERY (Line 1 - Line 2 + Line 3)	($61,300,153)
5.	FINAL TRUE-UP (January 2019 - December 2019) (Per True-Up filed March 2, 2020)	35,821,098
6.	TOTAL OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2021 (Line 4 + Line 5) To be included in the 12-month projected period January 2021 through December 2021 (2021 Schedule E1, line 29)	($25,479,055)
7.	JURISDICTIONAL MWH SALES (Projected January 2021 through December 2021)	19,545,089
8.	TRUE-UP FACTOR - cents/kWh (Using Effective MWh Sales of 19,514,116)	**0.1306**

TAMPA ELECTRIC COMPANY
CALCULATION OF ESTIMATED TRUE-UP
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

SCHEDULE E1-B
REVISED 8/12/20

		ACTUAL						ESTIMATED						
		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	TOTAL
A. 1.	Fuel Cost of System Net Generation	36,433,217	28,053,617	31,379,547	25,492,298	27,707,925	32,535,096	40,708,751	43,874,042	41,164,058	38,341,342	36,354,561	42,572,326	424,616,780
2.	Fuel Cost of Power Sold (1)	87,963	93,206	310,050	36,113	55,255	64,665	66,154	67,203	70,381	73,668	72,806	77,059	1,074,523
3.	Fuel Cost of Purchased Power	2,767	(3,817)	0	129,561	78,534	71,725	0	0	0	0	0	61,224	339,994
3a.	Demand and Non-Fuel Cost of Purchased Pwr	0	0	0	0	0	0	0	0	0	0	0	0	0
3b.	Payments to Qualifying Facilities	88,714	291,342	171,178	218,027	120,336	107,388	189,360	211,880	194,840	198,000	195,750	167,730	2,154,545
4.	Energy Cost of Economy Purchases	314,503	260,337	443,296	3,913,922	9,221,266	8,677,950	6,321,920	6,455,240	6,252,140	6,726,330	4,450,850	686,196	53,723,950
5.	Adj. Big Bend Units 1-4 Igniters Conversion Project	357,864	355,627	353,391	351,154	239,240	0	0	0	0	0	0	0	1,657,276
5a.	Adjustment TRANSCO Refund	0	0	0	0	0	0	(461,004)	0	0	0	0	0	(461,004)
5b.	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**TOTAL FUEL & NET POWER TRANS.**	**37,109,102**	**28,863,900**	**32,037,362**	**30,068,849**	**37,312,046**	**41,327,494**	**46,692,873**	**50,473,959**	**47,540,657**	**45,192,004**	**40,928,355**	**43,410,417**	**480,957,018**
(1)	Includes Gains													
B. 1.	Jurisdictional MWH Sales	1,455,302	1,379,292	1,359,170	1,534,770	1,528,679	1,775,552	1,873,355	1,902,497	1,937,665	1,778,494	1,498,483	1,410,765	19,434,024
2.	Non-Jurisdictional MWH Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	**TOTAL SALES (LINE B1+B2)**	**1,455,302**	**1,379,292**	**1,359,170**	**1,534,770**	**1,528,679**	**1,775,552**	**1,873,355**	**1,902,497**	**1,937,665**	**1,778,494**	**1,498,483**	**1,410,765**	**19,434,024**
4.	**Jurisdictional % of Total Sales**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**-**
C. 1.	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	43,077,818	40,611,832	40,003,085	45,869,774	45,793,723	46,790,142	49,812,875	50,467,287	51,635,873	46,712,539	38,618,102	36,095,556	535,488,606
1a.	Jurisdictional Fuel Recovery Revenue Credit	0	0	0	0	0	(25,874,741)	(26,871,639)	(27,412,832)	0	0	0	0	(80,159,212)
2.	True-up Provision	(2,561,836)	(2,561,836)	(2,561,836)	(2,561,836)	(2,561,836)	0	0	0	0	0	0	0	(12,809,180)
2a.	Incentive Provision	(345,111)	(345,111)	(345,111)	(345,111)	(345,111)	(345,111)	(345,111)	(345,111)	(345,111)	(345,111)	(345,111)	(345,109)	(4,141,330)
2b.	2018 Optimization Mechanism Gains	(93,363)	(93,363)	(93,363)	(93,363)	(93,363)	(93,363)	(93,363)	(93,363)	(93,363)	(93,363)	(93,363)	(93,360)	(1,120,353)
3.	**FUEL REVENUE APPLICABLE TO PERIOD**	**40,077,508**	**37,611,522**	**37,002,775**	**42,869,464**	**42,793,413**	**20,476,927**	**22,502,762**	**22,615,981**	**51,197,399**	**46,274,065**	**38,179,628**	**35,657,087**	**437,258,531**
4.	Total Fuel and Net Power Transactions (Line A6)	37,109,102	28,863,900	32,037,362	30,068,849	37,312,046	41,327,494	46,692,873	50,473,959	47,540,657	45,192,004	40,928,355	43,410,417	480,957,018
5.	Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	37,109,102	28,863,900	32,037,362	30,068,849	37,312,046	41,327,494	46,692,873	50,473,959	47,540,657	45,192,004	40,928,355	43,410,417	480,957,018
5a.	Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	-
5b.	Jurisdictional Sales Adjusted for Line Losses	37,109,102	28,863,900	32,037,362	30,068,849	37,312,046	41,327,494	46,692,873	50,473,959	47,540,657	45,192,004	40,928,355	43,410,417	480,957,018
5c.	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS**	**37,109,102**	**28,863,900**	**32,037,362**	**30,068,849**	**37,312,046**	**41,327,494**	**46,692,873**	**50,473,959**	**47,540,657**	**45,192,004**	**40,928,355**	**43,410,417**	**480,957,018**
7.	Over/(Under) Recovery	2,968,406	8,747,622	4,965,413	12,800,615	5,481,367	(20,850,567)	(24,190,111)	(27,857,978)	3,656,742	1,082,061	(2,748,727)	(7,753,330)	(43,698,487)
7a.	FUEL SAVINGS CREDIT FOR LAKE HANCOCK GENERATION PER SECOND SoBRA	0	236,322	0	0	0	0	0	0	0	0	0	0	236,322
8.	Interest Provision	10,982	21,803	40,744	35,565	2,951	3,422	4,052	(1,844)	(5,717)	(4,960)	(5,229)	(6,911)	94,858
9.	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD**													**(43,367,307)**

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TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

SCHEDULE E2
REVISED 8/12/20

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Actual						Estimated						TOTAL
	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	PERIOD
1. Fuel Cost of System Net Generation	36,433,217	28,053,617	31,379,547	25,492,298	27,707,925	32,535,096	40,708,751	43,874,042	41,164,058	38,341,342	36,354,561	42,572,326	424,616,780
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold (1)	87,963	93,206	310,050	36,113	55,255	64,665	66,154	67,203	70,381	73,668	72,806	77,059	1,074,523
4. Fuel Cost of Purchased Power	2,767	(3,817)	0	129,561	78,534	71,725	0	0	0	0	0	61,224	339,994
5. Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Payments to Qualifying Facilities	88,714	291,342	171,178	218,027	120,336	107,388	189,360	211,880	194,840	198,000	195,750	167,730	2,154,545
7. Energy Cost of Economy Purchases	314,503	260,337	443,296	3,913,922	9,221,266	8,677,950	6,321,920	6,455,240	6,252,140	6,726,330	4,450,850	686,196	53,723,950
8. Adj. Big Bend Units 1-4 Igniters Conversion Project	357,864	355,627	353,391	351,154	239,240	0	0	0	0	0	0	0	1,657,276
9. Adjustment TRANSCO Refund	0	0	0	0	0	0	(461,004)	0	0	0	0	0	(461,004)
10. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
11. TOTAL FUEL & NET POWER TRANSACTIONS	**37,109,102**	**28,863,900**	**32,037,362**	**30,068,849**	**37,312,046**	**41,327,494**	**46,692,873**	**50,473,959**	**47,540,657**	**45,192,004**	**40,928,355**	**43,410,417**	**480,957,018**
12. Jurisdictional MWH Sold	1,455,302	1,379,292	1,359,170	1,534,770	1,528,679	1,775,552	1,873,355	1,902,497	1,937,665	1,778,494	1,498,483	1,410,765	19,434,024
13. Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	-
14. Jurisdictional Total Fuel & Net Power Transactions (Line 11 * Line 13)	37,109,102	28,863,900	32,037,362	30,068,849	37,312,046	41,327,494	46,692,873	50,473,959	47,540,657	45,192,004	40,928,355	43,410,417	480,957,018
15. Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	-
16. Jurisdictional Sales Adjusted for Line Losses (Line 14 * Line 15)	37,109,102	28,863,900	32,037,362	30,068,849	37,312,046	41,327,494	46,692,873	50,473,959	47,540,657	45,192,004	40,928,355	43,410,417	480,957,018
17. Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
18. JURISD. TOTAL FUEL & NET PWR. TRANS. (LINE 16+17)	**37,109,102**	**28,863,900**	**32,037,362**	**30,068,849**	**37,312,046**	**41,327,494**	**46,692,873**	**50,473,959**	**47,540,657**	**45,192,004**	**40,928,355**	**43,410,417**	**480,957,018**
19. Cost Per kWh Sold (Cents/kWh)	2.5499	2.0927	2.3571	1.9592	2.4408	2.3276	2.4925	2.6530	2.4535	2.5410	2.7313	3.0771	2.4748
20. Optimization Mechanism (Cents/kWh) (2)	(0.0064)	(0.0068)	(0.0069)	(0.0061)	(0.0061)	(0.0053)	(0.0050)	(0.0049)	(0.0048)	(0.0052)	(0.0062)	(0.0066)	(0.0059)
21. True-up (Cents/kWh) (2)	0.1760	0.1857	0.1885	0.1669	0.1676	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0737
22. Total (Cents/kWh) (Line 19+20+21)	2.7195	2.2716	2.5387	2.1200	2.6023	2.3223	2.4875	2.6481	2.4487	2.5358	2.7251	3.0705	2.5427
23. Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
24. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	2.7215	2.2732	2.5406	2.1215	2.6042	2.3240	2.4893	2.6501	2.4505	2.5377	2.7271	3.0727	2.5445
25. GPIF Adjusted for Taxes (Cents/kWh) (2)	0.0237	0.0250	0.0254	0.0225	0.0226	0.0194	0.0184	0.0181	0.0178	0.0194	0.0230	0.0245	0.0217
26. TOTAL RECOVERY FACTOR (LINE 24+25)	**2.7452**	**2.2982**	**2.5660**	**2.1440**	**2.6268**	**2.3434**	**2.5077**	**2.6682**	**2.4683**	**2.5571**	**2.7501**	**3.0972**	**2.5662**
27. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**2.745**	**2.298**	**2.566**	**2.144**	**2.627**	**2.343**	**2.508**	**2.668**	**2.468**	**2.557**	**2.750**	**3.097**	**2.566**

(1) Includes Gains
(2) Based on Jurisdictional Sales Only

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Exhibit No. MAS-2
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Revised: 08/12/2020

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD: JANUARY 2020 THROUGH JUNE 2020

SCHEDULE E3

	ACTUAL					
	Jan-20	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	0	0	0	0	56,132	111,650
3. COAL	5,976,802	1,044,084	1,258,618	355,640	354,196	2,645,478
4. NATURAL GAS	30,456,415	27,009,533	30,120,929	25,136,658	27,297,597	29,777,968
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**36,433,217**	**28,053,617**	**31,379,547**	**25,492,298**	**27,707,925**	**32,535,096**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	0	0	0	0	205	251
10. COAL	179,947	(1,208)	(664)	(1,743)	(514)	78,044
11. NATURAL GAS	1,246,294	1,336,780	1,521,132	1,329,024	1,309,506	1,501,629
12. SOLAR	59,607	69,676	104,627	100,443	134,680	114,484
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,485,848**	**1,405,248**	**1,625,095**	**1,427,724**	**1,443,877**	**1,694,408**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	0	0	0	0	440	759
17. COAL (TON)	82,330	0	(2,255)	0	0	41,559
18. NATURAL GAS (MCF)	10,057,418	10,067,881	11,701,767	9,429,039	9,453,126	11,750,533
19. SOLAR	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	0	0	0	0	2,567	4,422
23. COAL	1,900,555	0	(51,555)	0	0	932,418
24. NATURAL GAS	10,298,745	10,315,146	11,991,164	9,682,959	9,658,693	11,965,018
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**12,199,300**	**10,315,146**	**11,939,609**	**9,682,959**	**9,661,260**	**12,901,858**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.00	0.00	0.00	0.00	0.01	0.01
30. COAL	12.11	(0.09)	(0.04)	(0.13)	(0.03)	4.61
31. NATURAL GAS	83.88	95.13	93.60	93.09	90.69	88.62
32. SOLAR	4.01	4.96	6.44	7.04	9.33	6.76
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	0.00	0.00	0.00	0.00	127.57	147.10
37. COAL ($/TON)	72.60	0.00	(558.15)	0.00	0.00	63.66
38. NATURAL GAS ($/MCF)	3.03	2.68	2.57	2.67	2.89	2.53
39. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	0.00	0.00	0.00	0.00	21.87	25.25
43. COAL	3.14	0.00	(24.41)	0.00	0.00	2.84
44. NATURAL GAS	2.96	2.62	2.51	2.60	2.83	2.49
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**2.99**	**2.72**	**2.63**	**2.63**	**2.87**	**2.52**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	0	0	0	0	12,522	17,618
50. COAL	10,562	0	77,643	0	0	11,947
51. NATURAL GAS	8,263	7,716	7,883	7,286	7,376	7,968
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**8,210**	**7,340**	**7,347**	**6,782**	**6,691**	**7,614**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	0.00	0.00	0.00	0.00	27.38	44.48
57. COAL	3.32	(86.43)	(189.55)	(20.40)	(68.91)	3.39
58. NATURAL GAS	2.44	2.02	1.98	1.89	2.08	1.98
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**2.45**	**2.00**	**1.93**	**1.79**	**1.92**	**1.92**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2020 THROUGH DECEMBER 2020

SCHEDULE E3

	Estimated						
	Jul-20	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**TOTAL**
FUEL COST OF SYSTEM NET GENERATION ($)							
1. HEAVY OIL	0	0	0	0	0	0	0
2. LIGHT OIL	673,588	608,665	539,378	501,308	398,286	478,444	3,367,451
3. COAL	4,219,114	4,312,681	4,246,528	2,034,424	1,618,459	2,970,432	31,036,456
4. NATURAL GAS	35,816,049	38,952,696	36,378,152	35,805,610	34,337,816	39,123,450	390,212,873
5. SOLAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL ($)	**40,708,751**	**43,874,042**	**41,164,058**	**38,341,342**	**36,354,561**	**42,572,326**	**424,616,780**
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	0	0	0	0	0	0	0
9. LIGHT OIL	2,658	2,658	2,572	2,529	2,100	2,658	15,631
10. COAL	104,340	108,120	107,800	50,220	39,680	75,210	739,232
11. NATURAL GAS	1,539,593	1,612,643	1,460,929	1,372,221	1,157,850	1,341,443	16,729,044
12. SOLAR	135,030	130,700	112,590	112,270	89,140	76,390	1,239,637
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	**1,781,621**	**1,854,121**	**1,683,891**	**1,537,240**	**1,288,770**	**1,495,701**	**18,723,544**
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	0	0	0	0	0	0	0
16. LIGHT OIL (BBL)	4,986	4,986	4,824	4,744	3,940	4,986	29,665
17. COAL (TON)	59,450	60,940	60,180	28,920	22,850	42,230	396,204
18. NATURAL GAS (MCF)	11,016,735	11,636,535	10,634,604	10,278,364	9,091,264	9,641,105	124,758,371
19. SOLAR	0	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)							
21. HEAVY OIL	0	0	0	0	0	0	0
22. LIGHT OIL	29,229	29,229	28,286	27,814	23,100	29,229	173,875
23. COAL	1,337,720	1,371,170	1,354,020	650,620	514,200	950,270	8,959,418
24. NATURAL GAS	11,314,161	11,940,981	10,908,824	10,513,806	9,299,520	9,892,681	127,781,699
25. SOLAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	**12,681,110**	**13,341,380**	**12,291,130**	**11,192,240**	**9,836,820**	**10,872,180**	**136,914,992**
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.15	0.14	0.15	0.16	0.16	0.18	0.08
30. COAL	5.85	5.83	6.40	3.27	3.08	5.02	3.95
31. NATURAL GAS	86.42	86.98	86.76	89.27	89.84	89.69	89.35
32. SOLAR	7.58	7.05	6.69	7.30	6.92	5.11	6.62
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT							
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	135.10	122.07	111.81	105.67	101.09	95.96	113.52
37. COAL ($/TON)	70.97	70.77	70.56	70.35	70.83	70.34	78.33
38. NATURAL GAS ($/MCF)	3.25	3.35	3.42	3.48	3.78	4.06	3.13
39. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)							
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	23.05	20.82	19.07	18.02	17.24	16.37	19.37
43. COAL	3.15	3.15	3.14	3.13	3.15	3.13	3.46
44. NATURAL GAS	3.17	3.26	3.33	3.41	3.69	3.95	3.05
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.21**	**3.29**	**3.35**	**3.43**	**3.70**	**3.92**	**3.10**
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	0	0	0	0	0	0	0
49. LIGHT OIL	10,996	10,996	10,998	10,998	11,000	10,996	11,124
50. COAL	12,821	12,682	12,560	12,955	12,959	12,635	12,120
51. NATURAL GAS	7,349	7,405	7,467	7,662	8,032	7,375	7,638
52. SOLAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**7,118**	**7,196**	**7,299**	**7,281**	**7,633**	**7,269**	**7,312**
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	25.34	22.90	20.97	19.82	18.97	18.00	21.54
57. COAL	4.04	3.99	3.94	4.05	4.08	3.95	4.20
58. NATURAL GAS	2.33	2.42	2.49	2.61	2.97	2.92	2.33
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**2.28**	**2.37**	**2.44**	**2.49**	**2.82**	**2.85**	**2.27**

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: January 2020

(A) PLANT/UNIT		(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR		1.6	107	9.0	-	31.7	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR		19.4	2,434	16.9	-	41.4	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR		1.4	123	11.8	-	28.6	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR		70.3	9,987	19.1	-	47.5	-	SOLAR	-	-	-	-	-	-
BALM SOLAR		74.4	10,416	18.8	-	47.5	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR		74.5	10,603	19.1	-	47.4	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR		61.1	8,151	17.9	-	44.9	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR		55.4	6,605	16.0	-	42.9	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR		37.5	4,583	16.4	-	39.6	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR		49.5	6,200	16.8	-	44.9	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	(3)	74.8	(11)	-	-	-	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR		74.5	409	-	-	-	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL		**594.4**	**59,607**	**13.5**	-	**32.5**	-	**SOLAR**	-	-	-	-	-	-
BIG BEND #1 TOTAL		**315**	**36,687**	**15.7**	**100.0**	**42.4**	**13,129**	**GAS**	**469,929**	**1,025,000**	**481,677.7**	**1,423,066**	**3.88**	**3.03**
BIG BEND #2 TOTAL		**350**	**81,100**	**31.1**	**46.9**	**71.5**	**11,351**	**GAS**	**898,078**	**1,025,000**	**920,530.2**	**2,719,609**	**3.35**	**3.03**
B.B.#3 (COAL)		400	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)		355	181,071	68.6	98.9	68.6	-	GAS	2,013,080	1,025,000	2,063,407.0	6,096,117	3.37	3.03
BIG BEND #3 TOTAL		**355**	**181,071**	**68.6**	**98.9**	**68.6**	**11,396**	-	-	-	**2,063,407.0**	**6,096,117**	**3.37**	-
B.B.#4 (COAL)		442	181,228	55.1	90.4	70.1	-	COAL	82,330	23,084,544	1,900,554.7	5,976,802	3.30	72.60
B.B.#4 (GAS)		195	6,934	4.8	90.4	82.7	-	GAS	71,983	1,025,000	73,782.2	217,982	3.14	3.03
BIG BEND #4 TOTAL		**442**	**188,162**	**57.2**	**90.4**	**67.7**	**10,508**	-	-	-	**1,974,336.9**	**6,194,784**	**3.29**	-
B.B. IGNITION		-	-	-	-	-	-	GAS	9,861	1,025,000	10,108.0	29,863	-	3.03
BIG BEND CT #4 TOTAL	(3)	**61**	**(7)**	**0.0**	**77.1**	**0.0**	**0**	**GAS**	**2,625**	**1,025,000**	**2,690.5**	**7,950**	**(113.57)**	**3.03**
BIG BEND STATION TOTAL		**1,523**	**487,013**	**45.7**	**83.5**	**45.7**	**11,181**	-	-	-	**5,442,642.3**	**16,471,389**	**3.38**	-
POLK #1 GASIFIER	(3)	157	(1,281)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)		177	23,026	18.9	98.0	66.4	11,131	GAS	250,051	1,025,000	256,302.0	757,217	2.39	3.03
POLK #1 ST		85	8,681	13.2	97.8	47.2	-	-	-	-	-	-	-	-
POLK #1 TOTAL		**245**	**30,426**	**16.9**	**97.9**	**59.3**	**8,424**	-	-	-	**256,302.0**	**757,217**	**2.49**	-
POLK #2 ST DUCT FIRING		120	12,844	14.4	-	85.6	8,400	GAS	105,258	1,025,000	107,889.0	318,747	2.48	3.03
POLK #2 ST W/O DUCT FIRING		360	229,912	85.8	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL		**480**	**242,756**	**68.0**	**99.4**	**85.6**	-	**GAS**	-	-	**107,889.0**	**318,747**	**0.13**	-
POLK #2 CT (GAS)		180	99,676	74.4	98.0	79.9	11,162	GAS	1,085,419	1,025,000	1,112,554.0	3,286,923	3.30	3.03
POLK #2 CT (OIL)		187	0	0.0	98.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL		**180**	**99,676**	**74.4**	**98.0**	**79.9**	**11,162**	-	-	-	**1,112,554.0**	**3,286,923**	**3.30**	-
POLK #3 CT (GAS)		180	93,794	70.0	99.9	80.4	10,921	GAS	999,359	1,025,000	1,024,343.0	3,026,313	3.23	3.03
POLK #3 CT (OIL)		187	0	0.0	99.9	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL		**180**	**93,794**	**70.0**	**99.9**	**80.4**	**10,921**	-	-	-	**1,024,343.0**	**3,026,313**	**3.23**	-
POLK #4 TOTAL		**180**	**97,077**	**72.5**	**100.0**	**81.2**	**10,844**	GAS	**1,026,987**	**1,025,000**	**1,052,662.0**	**3,109,978**	**3.20**	**3.03**
POLK #5 TOTAL		**180**	**103,520**	**77.3**	**99.8**	**81.4**	**10,830**	GAS	**1,093,798**	**1,025,000**	**1,121,143.0**	**3,312,298**	**3.20**	**3.03**
POLK #2 CC TOTAL		**1,200**	**636,823**	**71.3**	**99.4**	**71.3**	**6,938**	GAS	-	-	**4,418,591.0**	**13,054,259**	**2.05**	-
POLK STATION TOTAL		**1,445**	**667,249**	**62.2**	**99.2**	**62.2**	**7,006**	-	-	-	**4,674,893.0**	**13,811,476**	**2.07**	-

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: January 2020

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
BAYSIDE ST 1	243	89,274	49.4	99.3	49.4	-		-	-	-	-	-	-
BAYSIDE CT1A	183	52,833	38.8	99.3	65.2	11,858	GAS	611,209	1,025,000	626,489.1	1,850,896	3.50	3.03
BAYSIDE CT1B	183	54,659	40.1	97.9	64.8	11,888	GAS	633,927	1,025,000	649,775.4	1,919,692	3.51	3.03
BAYSIDE CT1C	183	51,465	37.8	100.0	64.5	11,635	GAS	584,174	1,025,000	598,778.6	1,769,028	3.44	3.03
BAYSIDE UNIT 1 TOTAL	**792**	**248,231**	**42.1**	**99.1**	**42.1**	**7,554**	**GAS**	**1,829,310**	**1,025,000**	**1,875,043.0**	**5,539,616**	**2.23**	**3.03**
BAYSIDE ST 2	315	7,290	3.1	71.2	27.2	-		-	-	-	-	-	-
BAYSIDE CT2A	183	4,281	3.1	66.4	52.4	12,836	GAS	53,608	1,025,000	54,948.3	162,338	3.79	3.03
BAYSIDE CT2B	183	3,621	2.7	73.0	63.3	12,403	GAS	43,809	1,025,000	44,904.2	132,665	3.66	3.03
BAYSIDE CT2C	183	4,805	3.5	73.0	60.5	12,632	GAS	59,212	1,025,000	60,692.5	179,309	3.73	3.03
BAYSIDE CT2D	183	2,312	1.7	73.0	60.3	12,533	GAS	28,271	1,025,000	28,977.4	85,612	3.70	3.03
BAYSIDE UNIT 2 TOTAL	**1,047**	**22,309**	**2.9**	**71.3**	**25.0**	**8,496**	**GAS**	**184,900**	**1,025,000**	**189,522.4**	**559,924**	**2.51**	**3.03**
BAYSIDE UNIT 3 TOTAL	**61**	**324**	**0.7**	**100.0**	**88.3**	**10,933**	**GAS**	**3,459**	**1,025,000**	**3,545.9**	**10,476**	**3.23**	**3.03**
BAYSIDE UNIT 4 TOTAL	**61**	**268**	**0.6**	**100.0**	**86.4**	**10,939**	**GAS**	**2,863**	**1,025,000**	**2,934.0**	**8,668**	**3.23**	**3.03**
BAYSIDE UNIT 5 TOTAL	**61**	**601**	**1.3**	**100.0**	**77.5**	**13,351**	**GAS**	**7,830**	**1,025,000**	**8,025.6**	**23,711**	**3.95**	**3.03**
BAYSIDE UNIT 6 TOTAL	**61**	**246**	**0.5**	**100.0**	**85.0**	**10,934**	**GAS**	**2,628**	**1,025,000**	**2,693.5**	**7,957**	**3.23**	**3.03**
BAYSIDE STATION TOTAL	**2,083**	**271,979**	**17.5**	**85.2**	**17.5**	**7,654**	**GAS**	**2,030,990**	**1,025,000**	**2,081,764.4**	**6,150,352**	**2.26**	**3.03**
SYSTEM	**5,645**	**1,485,848**	**35.4**	**88.7**	**37.7**	**8,212**	**-**	**-**	**-**	**12,199,299.8**	**36,433,217**	**2.45**	**-**

LEGEND:
- **B.B. = BIG BEND**
- **CT = COMBUSTION TURBINE**
- **CC = COMBINED CYCLE**
- **ST = STEAM TURBINE**

Footnotes:
[1] **As burned fuel cost system total includes ignition.**
[2] **Fuel burned (MM BTU) system total excludes ignition.**
[3] **Station Service**

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: February 2020

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR	1.6	114	10.2	-	29.1	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.4	2,733	20.2	-	46.2	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.4	136	14.0	-	31.6	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.3	10,428	21.3	-	49.8	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.4	11,172	21.6	-	48.9	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.5	11,497	22.2	-	50.1	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	61.1	8,960	21.1	-	48.1	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	55.4	7,515	19.5	-	46.0	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.5	4,918	18.8	-	41.8	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.5	1,280	3.7	-	45.4	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR (3)	74.8	(33)	-	-	-	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.5	10,956	26.6	-	47.6	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	**594.4**	**69,676**	**16.8**	**-**	**37.3**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
BIG BEND #1 TOTAL	**315**	**14,104**	**6.4**	**100.0**	**40.0**	**13,421**	**GAS**	**184,671**	**1,025,000**	**189,288.9**	**495,427**	**3.51**	**2.68**
BIG BEND #2 TOTAL (4)	**350**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**104**	**1,025,000**	**106.2**	**278**	**0.00**	**2.67**
B.B.#3 (COAL)	400	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	355	149,183	60.4	98.6	62.7	-	GAS	1,621,728	1,025,000	1,662,271.0	4,350,678	2.92	2.68
BIG BEND #3 TOTAL	**355**	**149,183**	**60.4**	**98.6**	**62.7**	**11,142**	**-**	**-**	**-**	**1,662,271.0**	**4,350,678**	**2.92**	**-**
B.B.#4 (COAL) (5)	442	0	0.0	0.0	0.0	-	COAL	0	0	0.0	1,054,713	0.00	0.00
B.B.#4 (GAS)	195	0	0.0	0.0	0.0	-	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #4 TOTAL	**442**	**0**	**0.0**	**0.0**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**1,054,713**	**0.00**	**-**
B.B. IGNITION	-	-	-	-	-	-	GAS	4,325	1,025,000	4,433.0	11,603	-	2.68
BIG BEND CT #4 TOTAL	**61**	**346**	**0.8**	**87.0**	**68.5**	**18,474**	**GAS**	**6,236**	**1,025,000**	**6,391.9**	**16,730**	**4.84**	**2.68**
BIG BEND STATION TOTAL	**1,523**	**163,633**	**16.4**	**74.5**	**17.0**	**11,355**	**-**	**-**	**-**	**1,858,058.0**	**5,929,429**	**3.62**	**-**
POLK #1 GASIFIER (3),(6)	157	(1,208)	-	-	-	-	COAL	-	-	-	(10,629)	0.88	-
POLK #1 CT (GAS)	177	12,067	10.2	81.1	59.2	13,007	GAS	153,123	1,025,000	156,951.0	410,789	2.48	2.68
POLK #1 ST	85	4,501	7.1	81.1	42.1	-	-	-	-	-	-	-	-
POLK #1 TOTAL	**245**	**15,360**	**9.1**	**81.1**	**52.7**	**10,218**	**-**	**-**	**-**	**156,951.0**	**400,160**	**2.61**	**-**
POLK #2 ST DUCT FIRING	120	12,173	14.6	-	78.4	8,400	GAS	99,753	1,025,000	102,248.0	267,615	2.20	2.68
POLK #2 ST W/O DUCT FIRING	360	212,868	85.0	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	**480**	**225,041**	**67.4**	**88.1**	**78.4**	**-**	**GAS**	**-**	**-**	**102,248.0**	**267,615**	**0.12**	**-**
POLK #2 CT (GAS)	180	101,894	81.3	100.0	82.1	11,169	GAS	1,110,285	1,025,000	1,138,042.0	2,978,608	2.92	2.68
POLK #2 CT (OIL)	187	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**180**	**101,894**	**81.3**	**100.0**	**82.1**	**11,169**	**-**	**-**	**-**	**1,138,042.0**	**2,978,608**	**2.92**	**-**
POLK #3 CT (GAS)	180	103,389	82.5	100.0	83.5	10,847	GAS	1,094,082	1,025,000	1,121,434.0	2,935,140	2.84	2.68
POLK #3 CT (OIL)	187	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**180**	**103,389**	**82.5**	**100.0**	**83.5**	**10,847**	**-**	**-**	**-**	**1,121,434.0**	**2,935,140**	**2.84**	**-**
POLK #4 TOTAL	**180**	**58,498**	**46.7**	**82.2**	**82.1**	**10,854**	GAS	**619,457**	**1,025,000**	**634,943.0**	**1,661,842**	**2.84**	**2.68**
POLK #5 TOTAL	**180**	**104,317**	**83.3**	**97.8**	**85.2**	**10,761**	GAS	**1,095,209**	**1,025,000**	**1,122,589.0**	**2,938,163**	**2.82**	**2.68**
POLK #2 CC TOTAL	**1,200**	**593,139**	**71.0**	**92.2**	**71.0**	**6,945**	GAS	**-**	**-**	**4,119,256.0**	**10,781,368**	**1.82**	**-**
POLK STATION TOTAL	**1,445**	**608,498**	**60.6**	**90.4**	**60.6**	**7,027**	**-**	**-**	**-**	**4,276,207.0**	**11,181,528**	**1.84**	**-**

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: February 2020

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
BAYSIDE ST 1	243	71,462	42.3	88.4	61.2	-		-	-	-	-	-	-
BAYSIDE CT1A	183	44,397	34.9	87.5	70.4	11,356	GAS	491,852	1,025,000	504,148.7	1,319,513	2.97	2.68
BAYSIDE CT1B	183	41,937	32.9	88.6	71.3	11,412	GAS	466,927	1,025,000	478,599.9	1,252,645	2.99	2.68
BAYSIDE CT1C	183	45,546	35.8	88.9	70.0	11,215	GAS	498,333	1,025,000	510,791.7	1,336,900	2.94	2.68
BAYSIDE UNIT 1 TOTAL	**792**	**203,342**	**36.9**	**88.3**	**53.4**	**7,345**	**GAS**	**1,457,112**	**1,025,000**	**1,493,540.3**	**3,909,058**	**1.92**	**2.68**
BAYSIDE ST 2	315	123,147	56.2	95.9	56.2	-		-	-	-	-	-	-
BAYSIDE CT2A	183	63,374	49.8	83.4	69.7	11,192	GAS	691,968	1,025,000	709,267.9	1,856,373	2.93	2.68
BAYSIDE CT2B	183	55,494	43.6	99.0	70.5	11,448	GAS	619,782	1,025,000	635,276.4	1,662,716	3.00	2.68
BAYSIDE CT2C	183	59,487	46.7	99.1	70.7	11,427	GAS	663,202	1,025,000	679,782.4	1,779,201	2.99	2.68
BAYSIDE CT2D	183	55,942	43.9	99.1	71.0	11,318	GAS	617,714	1,025,000	633,156.9	1,657,168	2.96	2.68
BAYSIDE UNIT 2 TOTAL	**1,047**	**357,444**	**49.1**	**95.4**	**49.1**	**7,435**	**GAS**	**2,592,666**	**1,025,000**	**2,657,483.6**	**6,955,458**	**1.95**	**2.68**
BAYSIDE UNIT 3 TOTAL	**61**	**288**	**0.7**	**88.3**	**58.3**	**11,207**	**GAS**	**3,149**	**1,025,000**	**3,227.3**	**8,447**	**2.93**	**2.68**
BAYSIDE UNIT 4 TOTAL	**61**	**802**	**1.9**	**99.4**	**85.2**	**10,545**	**GAS**	**8,248**	**1,025,000**	**8,453.1**	**22,124**	**2.76**	**2.68**
BAYSIDE UNIT 5 TOTAL	**61**	**987**	**2.3**	**96.2**	**83.7**	**12,165**	**GAS**	**11,708**	**1,025,000**	**12,000.4**	**31,409**	**3.18**	**2.68**
BAYSIDE UNIT 6 TOTAL	**61**	**579**	**1.4**	**96.1**	**86.3**	**10,669**	**GAS**	**6,025**	**1,025,000**	**6,175.8**	**16,164**	**2.79**	**2.68**
BAYSIDE STATION TOTAL	**2,083**	**563,441**	**38.9**	**92.6**	**38.9**	**7,420**	**GAS**	**4,078,908**	**1,025,000**	**4,180,880.5**	**10,942,660**	**1.94**	**2.68**
SYSTEM	**5,645**	**1,405,248**	**35.8**	**86.5**	**38.4**	**7,340**	**-**	**-**	**-**	**10,315,145.5**	**28,053,617**	**2.00**	**-**

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE
CC = COMBINED CYCLE
ST = STEAM TURBINE

Footnotes:
(1) **As burned fuel cost system total includes ignition.**
(2) **Fuel burned (MM BTU) system total excludes ignition.**
(3) **Station Service**
(4) **Test burn**
(5) **Consists of fixed costs and aerial survey adjustment.**
(6) **Polk's portion of the aerial survey adjustment.**

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Docket No. 20200001-EI
Exhibit No. MAS-2
Document No. 1, Page 10 of 31

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: March 2020

(A) PLANT/UNIT		(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR		1.6	262	22.0	-	52.7	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR		19.4	3,689	25.6	-	53.9	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR		1.4	187	18.0	-	37.4	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR		70.3	14,145	27.1	-	57.2	-	SOLAR	-	-	-	-	-	-
BALM SOLAR		74.4	14,250	25.8	-	54.7	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR		74.5	14,906	26.9	-	57.2	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR		61.1	11,320	24.9	-	55.6	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR		55.4	9,992	24.3	-	50.7	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR		37.5	6,233	22.4	-	46.3	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR		49.5	6,666	18.1	-	50.2	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR		74.8	6,316	-	-	-	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR		74.5	16,661	30.1	-	66.4	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL		**594.4**	**104,627**	**23.7**	-	**49.0**	-	**SOLAR**	-	-	-	-	-	-
BIG BEND #1 TOTAL		**315**	**14,427**	**6.7**	**99.7**	**41.6**	**13,393**	**GAS**	**188,329**	**1,026,000**	**193,225.6**	**499,273**	**3.46**	**2.65**
BIG BEND #2 TOTAL		**350**	**53,041**	**20.3**	**100.0**	**37.4**	**12,710**	**GAS**	**657,075**	**1,026,000**	**674,159.4**	**1,741,951**	**3.28**	**2.65**
B.B.#3 (COAL)		400	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)		355	136,445	51.6	88.2	58.6	-	GAS	1,524,951	1,026,000	1,564,602.1	4,042,754	2.96	2.65
BIG BEND #3 TOTAL		**355**	**136,445**	**51.6**	**88.2**	**58.6**	**11,467**	-	-	-	**1,564,602.1**	**4,042,754**	**2.96**	-
B.B.#4 (COAL)	(4)	442	0	0.0	0.0	0.0	-	COAL	(2,255)	0	(51,555.4)	1,258,618	0.00	(558.15)
B.B.#4 (GAS)		195	0	0.0	0.0	0.0	-	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #4 TOTAL		**442**	**0**	**0.0**	**0.0**	**0.0**	**0**	-	-	-	**(51,555.4)**	**1,258,618**	**0.00**	-
B.B. IGNITION		-	-	-	-	-	-	GAS	14,473	1,026,000	14,849.0	38,368	-	2.65
BIG BEND CT #4 TOTAL		**61**	**123**	**0.3**	**76.6**	**51.4**	**22,380**	**GAS**	**2,683**	**1,026,000**	**2,752.8**	**7,113**	**5.78**	**2.65**
BIG BEND STATION TOTAL		**1,523**	**204,036**	**16.9**	**71.7**	**25.3**	**11,933**	-	-	-	**2,383,184.6**	**7,588,077**	**3.72**	-
POLK #1 GASIFIER	(3)	157	(664)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)		177	74,207	63.1	89.3	70.7	11,822	GAS	855,041	1,026,000	877,272.1	2,121,712	2.07	2.48
POLK #1 ST		85	28,394	44.6	88.9	50.2	-	-	-	-	-	-	-	-
POLK #1 TOTAL		**245**	**101,937**	**56.6**	**89.2**	**63.4**	**8,606**	-	-	-	**877,272.1**	**2,121,712**	**2.08**	-
POLK #2 ST DUCT FIRING		120	17,450	19.6	-	89.7	8,400	GAS	142,865	1,026,000	146,579.1	354,507	2.03	2.48
POLK #2 ST W/O DUCT FIRING		360	239,795	89.6	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL		**480**	**257,245**	**72.0**	**98.7**	**89.7**	-	**GAS**	-	-	**146,579.1**	**354,507**	**0.14**	-
POLK #2 CT (GAS)		180	96,687	72.2	100.0	79.0	11,151	GAS	1,050,877	1,026,000	1,078,199.9	2,607,661	2.70	2.48
POLK #2 CT (OIL)		187	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL		**180**	**96,687**	**72.2**	**100.0**	**79.0**	**11,151**	-	-	-	**1,078,199.9**	**2,607,661**	**2.70**	-
POLK #3 CT (GAS)		180	102,583	76.6	100.0	80.9	10,850	GAS	1,084,862	1,026,000	1,113,068.7	2,691,993	2.62	2.48
POLK #3 CT (OIL)		187	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL		**180**	**102,583**	**76.6**	**100.0**	**80.9**	**10,850**	-	-	-	**1,113,068.7**	**2,691,993**	**2.62**	-
POLK #4 TOTAL		**180**	**104,894**	**78.3**	**98.7**	**83.2**	**10,697**	GAS	**1,093,645**	**1,026,000**	**1,122,079.3**	**2,713,786**	**2.59**	**2.48**
POLK #5 TOTAL		**180**	**103,923**	**77.6**	**100.0**	**82.8**	**10,712**	GAS	**1,084,992**	**1,026,000**	**1,113,202.0**	**2,692,314**	**2.59**	**2.48**
POLK #2 CC TOTAL		**1,200**	**665,332**	**74.5**	**99.3**	**75.5**	**6,873**	GAS	-	-	**4,573,128.9**	**11,060,261**	**1.66**	-
POLK STATION TOTAL		**1,445**	**767,269**	**54.9**	**96.1**	**54.9**	**7,104**	-	-	-	**5,450,401.0**	**13,181,973**	**1.72**	-

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SCHEDULE A4
PAGE 2 OF 2

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: March 2020

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
BAYSIDE ST 1	243	49,480	27.4	50.3	58.2	-		-	-	-	-	-	-
BAYSIDE CT1A	183	24,396	17.9	44.8	68.6	11,569	GAS	275,077	1,026,000	282,228.5	729,247	2.99	2.65
BAYSIDE CT1B	183	32,334	23.7	48.1	68.2	11,587	GAS	365,161	1,026,000	374,655.6	968,066	2.99	2.65
BAYSIDE CT1C	183	34,565	25.4	48.1	66.5	11,393	GAS	383,830	1,026,000	393,809.4	1,017,559	2.94	2.65
BAYSIDE UNIT 1 TOTAL	**792**	**140,774**	**23.9**	**48.0**	**50.8**	**7,464**	**GAS**	**1,024,068**	**1,026,000**	**1,050,693.5**	**2,714,872**	**1.93**	**2.65**
BAYSIDE ST 2	315	141,605	60.4	99.9	60.4	-		-	-	-	-	-	-
BAYSIDE CT2A	183	81,472	59.9	100.0	68.1	11,315	GAS	898,469	1,026,000	921,829.5	2,381,901	2.92	2.65
BAYSIDE CT2B	183	65,812	48.3	99.5	68.6	11,533	GAS	739,747	1,026,000	758,980.6	1,961,119	2.98	2.65
BAYSIDE CT2C	183	60,650	44.5	100.0	69.0	11,551	GAS	682,799	1,026,000	700,551.4	1,810,146	2.98	2.65
BAYSIDE CT2D	183	57,308	42.1	100.0	69.4	11,466	GAS	640,437	1,026,000	657,087.9	1,697,841	2.96	2.65
BAYSIDE UNIT 2 TOTAL	**1,047**	**406,847**	**52.2**	**99.9**	**52.2**	**7,468**	**GAS**	**2,961,452**	**1,026,000**	**3,038,449.4**	**7,851,007**	**1.93**	**2.65**
BAYSIDE UNIT 3 TOTAL	**61**	**185**	**0.4**	**100.0**	**84.3**	**11,045**	**GAS**	**1,993**	**1,026,000**	**2,044.6**	**5,283**	**2.86**	**2.65**
BAYSIDE UNIT 4 TOTAL	**61**	**538**	**1.2**	**100.0**	**89.3**	**10,791**	**GAS**	**5,661**	**1,026,000**	**5,807.4**	**15,006**	**2.79**	**2.65**
BAYSIDE UNIT 5 TOTAL	**61**	**583**	**1.3**	**100.0**	**81.5**	**11,085**	**GAS**	**6,299**	**1,026,000**	**6,462.8**	**16,699**	**2.86**	**2.65**
BAYSIDE UNIT 6 TOTAL	**61**	**236**	**0.5**	**100.0**	**83.1**	**10,887**	**GAS**	**2,501**	**1,026,000**	**2,565.9**	**6,630**	**2.81**	**2.65**
BAYSIDE STATION TOTAL	**2,083**	**549,163**	**37.0**	**70.2**	**37.0**	**7,477**	**GAS**	**4,001,974**	**1,026,000**	**4,106,023.5**	**10,609,497**	**1.93**	**2.65**
SYSTEM	**5,645**	**1,625,095**	**38.7**	**78.0**	**45.3**	**7,379**	**-**	**-**	**-**	**11,939,609.1**	**31,379,547**	**1.93**	**-**

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE
CC = COMBINED CYCLE
ST = STEAM TURBINE

Footnotes:
(1) As burned fuel cost system total includes ignition.
(2) Fuel burned (MM BTU) system total excludes ignition.
(3) Station Service
(4) Consists of fixed costs and aerial survey adjustment and prior month adjustments, details on Schedule A5, page 2.

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: April 2020

(A) PLANT/UNIT		(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR		1.6	274	23.8	-	47.6	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR		19.4	3,459	24.8	-	41.8	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR		1.4	172	17.1	-	30.7	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR		70.3	11,993	23.7	-	46.1	-	SOLAR	-	-	-	-	-	-
BALM SOLAR		74.4	12,550	23.4	-	44.5	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR		74.5	12,236	22.8	-	43.6	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR		61.1	9,589	21.8	-	41.5	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR		55.4	8,777	22.0	-	41.2	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR		37.5	6,058	22.4	-	39.6	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR		49.5	7,746	21.7	-	41.3	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR		74.8	13,460	-	-	-	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR		74.5	14,129	26.3	-	47.9	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL		**594.4**	**100,443**	**23.5**	**-**	**39.6**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
BIG BEND #1 TOTAL	(3),(5)	**305**	**(5,998)**	**(0.0)**	**95.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**(14,505)**	**0.24**	**0.00**
BIG BEND #2 TOTAL	(5)	**340**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**(50,606)**	**0.00**	**0.00**
B.B.#3 (COAL)		395	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	(3),(5)	345	(2,719)	0.1	100.0	19.1	-	GAS	681	1,027,000	699.7	(115,632)	4.25	(169.80)
BIG BEND #3 TOTAL		**345**	**(2,719)**	**0.1**	**100.0**	**19.1**	**0**	**-**	**-**	**-**	**699.7**	**(115,632)**	**4.25**	**-**
B.B.#4 (COAL)	(3),(4)	437	(1,345)	0.0	0.0	0.0	-	COAL	0	0	0.0	355,640	(26.44)	0.00
B.B.#4 (GAS)		185	0	0.0	0.0	0.0	-	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #4 TOTAL		**437**	**(1,345)**	**0.0**	**0.0**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**355,640**	**(26.44)**	**-**
B.B. IGNITION	(5)	-	-	-	-	-	-	GAS	647	1,027,000	664.0	609	-	0.94
BIG BEND CT #4 TOTAL	(5)	**56**	**655**	**1.6**	**100.0**	**85.6**	**14,679**	**GAS**	**9,362**	**1,027,000**	**9,614.5**	**24,752**	**3.78**	**2.64**
BIG BEND STATION TOTAL		**1,483**	**(9,407)**	**0.1**	**74.0**	**4.3**	**0**	**-**	**-**	**-**	**10,314.2**	**200,258**	**(2.13)**	**-**
POLK #1 GASIFIER	(3)	220	(398)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	(5)	150	45,317	41.7	63.0	68.4	12,250	GAS	540,533	1,027,000	555,127.0	1,520,199	2.41	2.81
POLK #1 ST		85	17,857	29.0	64.7	48.2	-	-	-	-	-	-	-	-
POLK #1 TOTAL		**235**	**62,776**	**37.1**	**63.6**	**60.9**	**8,843**	**-**	**-**	**-**	**555,127.0**	**1,520,199**	**2.42**	**-**
POLK #2 ST DUCT FIRING	(5)	120	8,412	9.7	-	81.0	8,400	GAS	68,800	1,027,000	70,658.0	196,647	2.34	2.86
POLK #2 ST W/O DUCT FIRING		341	211,603	86.2	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL		**461**	**220,015**	**66.3**	**93.0**	**81.0**	**-**	**GAS**	**-**	**-**	**70,658.0**	**196,647**	**0.09**	**-**
POLK #2 CT (GAS)	(5)	150	90,385	83.7	99.2	92.9	11,255	GAS	990,550	1,027,000	1,017,295.0	2,738,034	3.03	2.76
POLK #2 CT (OIL)		159	0	0.0	99.2	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL		**150**	**90,385**	**83.7**	**99.2**	**92.9**	**11,255**	**-**	**-**	**-**	**1,017,295.0**	**2,738,034**	**3.03**	**-**
POLK #3 CT (GAS)	(5)	150	90,166	83.5	95.1	96.2	10,957	GAS	961,981	1,027,000	987,955.0	2,665,021	2.96	2.77
POLK #3 CT (OIL)		159	0	0.0	95.1	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL		**150**	**90,166**	**83.5**	**95.1**	**96.2**	**10,957**	**-**	**-**	**-**	**987,955.0**	**2,665,021**	**2.96**	**-**
POLK #4 TOTAL	(5)	**150**	**82,315**	**76.2**	**99.9**	**99.0**	**10,753**	GAS	**861,859**	**1,027,000**	**885,129.0**	**2,398,918**	**2.91**	**2.78**
POLK #5 TOTAL	(5)	**150**	**98,932**	**91.6**	**100.0**	**97.8**	**10,813**	GAS	**1,041,660**	**1,027,000**	**1,069,785.0**	**2,877,448**	**2.91**	**2.76**
POLK #2 CC TOTAL		**1,061**	**581,813**	**76.2**	**96.1**	**76.2**	**6,928**	GAS	**-**	**-**	**4,030,822.0**	**10,876,068**	**1.87**	**-**
POLK STATION TOTAL		**1,296**	**644,589**	**69.1**	**90.2**	**69.1**	**7,115**	**-**	**-**	**-**	**4,585,949.0**	**12,396,267**	**1.92**	**-**

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SCHEDULE A4
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REVISED 6/19/20

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: April 2020

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
BAYSIDE ST 1	233	97,360	58.0	99.6	58.2	-		-	-	-	-	-	-
BAYSIDE CT1A	156	49,761	44.3	100.0	78.7	11,497	GAS	557,085	1,027,000	572,126.7	1,462,843	2.94	2.63
BAYSIDE CT1B	156	69,772	62.1	100.0	77.4	11,556	GAS	785,114	1,027,000	806,312.4	2,061,622	2.95	2.63
BAYSIDE CT1C	156	57,536	51.2	100.0	78.0	11,248	GAS	630,163	1,027,000	647,177.0	1,654,738	2.88	2.63
BAYSIDE UNIT 1 TOTAL [5]	**701**	**274,428**	**54.4**	**99.9**	**54.6**	**7,381**	**GAS**	**1,972,362**	**1,027,000**	**2,025,616.1**	**5,179,203**	**1.89**	**2.63**
BAYSIDE ST 2	305	148,198	67.5	98.5	67.5	-		-	-	-	-	-	-
BAYSIDE CT2A	156	82,645	73.6	100.0	78.9	11,199	GAS	901,220	1,027,000	925,552.6	2,333,464	2.82	2.59
BAYSIDE CT2B	156	62,301	55.5	100.0	79.1	11,398	GAS	691,464	1,027,000	710,133.6	1,790,358	2.87	2.59
BAYSIDE CT2C	156	63,241	56.3	100.0	79.2	11,463	GAS	705,865	1,027,000	724,923.6	1,827,645	2.89	2.59
BAYSIDE CT2D	156	60,901	54.2	94.0	79.1	11,419	GAS	677,152	1,027,000	695,435.0	1,753,301	2.88	2.59
BAYSIDE UNIT 2 TOTAL [5]	**929**	**417,286**	**62.4**	**98.5**	**62.4**	**7,324**	**GAS**	**2,975,701**	**1,027,000**	**3,056,044.8**	**7,704,768**	**1.85**	**2.59**
BAYSIDE UNIT 3 TOTAL [5]	**56**	**51**	**0.1**	**100.0**	**73.5**	**13,145**	**GAS**	**647**	**1,027,000**	**664.8**	**1,572**	**3.08**	**2.43**
BAYSIDE UNIT 4 TOTAL [5]	**56**	**178**	**0.4**	**100.0**	**79.4**	**12,809**	**GAS**	**2,219**	**1,027,000**	**2,277.7**	**5,476**	**3.08**	**2.47**
BAYSIDE UNIT 5 TOTAL [5]	**56**	**109**	**0.3**	**100.0**	**70.5**	**13,411**	**GAS**	**1,427**	**1,027,000**	**1,465.9**	**3,320**	**3.05**	**2.33**
BAYSIDE UNIT 6 TOTAL [5]	**56**	**47**	**0.1**	**100.0**	**68.7**	**13,249**	**GAS**	**610**	**1,027,000**	**626.8**	**1,434**	**3.05**	**2.35**
BAYSIDE STATION TOTAL	**1,854**	**692,099**	**51.8**	**99.2**	**51.8**	**7,350**	**GAS**	**4,952,966**	**1,027,000**	**5,086,696.0**	**12,895,773**	**1.86**	**2.60**
SYSTEM	**5,227**	**1,427,724**	**37.9**	**88.6**	**56.2**	**6,782**	**-**	**-**	**-**	**9,682,959.2**	**25,492,298**	**1.79**	**-**

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE
CC = COMBINED CYCLE
ST = STEAM TURBINE

Footnotes:
[1] **As burned fuel cost system total includes ignition**
[2] **Fuel burned (MM BTU) system total excludes ignition**
[3] **Station Service**
[4] **Consists of fixed costs**
[5] **Includes natural gas adjustment to March 2020, details on Schedule A5 page 2**

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: May 2020

(A) PLANT/UNIT		(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR		1.6	337	23.8	-	58.5	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR		19.4	4,538	28.3	-	54.8	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR		1.4	218	31.4	-	38.9	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR		70.3	15,737	20.9	-	60.5	-	SOLAR	-	-	-	-	-	-
BALM SOLAR		74.4	17,307	30.1	-	61.4	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR		74.5	16,838	31.3	-	60.0	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR		61.1	13,409	30.4	-	58.1	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR		55.4	12,148	29.5	-	57.0	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR		37.5	7,617	29.5	-	49.8	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR		49.5	10,052	27.3	-	53.6	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR		74.8	17,898	-	-	-	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR		74.5	18,581	32.2	-	63.0	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL		**594.4**	**134,680**	**30.5**	-	**53.1**	-	**SOLAR**	-	-	-	-	-	-
BIG BEND #1 TOTAL	(3)	**305**	**(4,652)**	**0.0**	**95.5**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BIG BEND #2 TOTAL		**340**	**15,092**	**6.0**	**97.0**	**52.9**	**11,898**	**GAS**	**175,356**	**1,024,000**	**179,566.8**	**506,378**	**3.36**	**2.89**
B.B.#3 (COAL)		395	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	(3)	345	(4,714)	0.0	61.2	0.0	-	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #3 TOTAL		**345**	**(4,714)**	**0.0**	**61.2**	**0.0**	**0**	-	-	-	**0.0**	**0**	**0.00**	-
B.B.#4 (COAL)	(3),(4)	437	(28)	0.0	0.2	0.0	-	COAL	0	0	0.0	354,196	(1,264.99)	0.00
B.B.#4 (GAS)	(3)	185	(2,217)	0.0	0.2	0.0	-	GAS	1	1,024,000	1.1	3	(0.00)	3.00
BIG BEND #4 TOTAL		**437**	**(2,245)**	**0.0**	**0.2**	**0.0**	**0**	-	-	-	**1.1**	**354,199**	**(15.78)**	-
B.B. IGNITION		-	-	-	-	-	-	GAS	20,809	1,024,000	21,307.9	60,088	-	2.89
BIG BEND CT #4 TOTAL		**56**	**712**	**1.7**	**100.0**	**84.8**	**14,796**	**GAS**	**10,288**	**1,024,000**	**10,534.4**	**29,706**	**4.17**	**2.89**
BIG BEND STATION TOTAL	(5)	**1,483**	**4,193**	**0.4**	**63.8**	**3.6**	**45,338**		-	-	**190,102.2**	**950,371**	**22.67**	-
POLK #1 GASIFIER	(3)	220	(486)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)		150	25,181	22.2	27.9	79.7	11,838	GAS	291,102	1,024,000	298,088.0	840,608	2.46	2.89
POLK #1 ST		85	8,991	14.0	27.4	51.2	-	-	-	-	-	-	-	-
POLK #1 TOTAL		**235**	**33,685**	**19.3**	**27.7**	**69.0**	**8,849**	-	-	-	**298,088.0**	**840,608**	**2.50**	-
POLK #2 ST DUCT FIRING		120	10,082	11.3	-	79.3	8,400	GAS	82,702	1,024,000	84,687.0	238,817	2.37	2.89
POLK #2 ST W/O DUCT FIRING		341	201,258	79.3	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL		**461**	**211,339**	**61.6**	**91.0**	**79.3**	-	**GAS**	-	-	**84,687.0**	**238,817**	**0.11**	-
POLK #2 CT (GAS)		150	73,435	65.8	82.2	92.9	11,321	GAS	811,908	1,024,000	831,394.0	2,344,531	3.19	2.89
POLK #2 CT (OIL)		159	2	0.0	82.2	9.9	12,571	LGT.OIL	3	5,829,600	19.8	383	19.15	127.67
POLK #2 TOTAL		**150**	**73,437**	**65.8**	**82.2**	**92.9**	**11,322**	-	-	-	**831,413.8**	**2,344,914**	**3.19**	-
POLK #3 CT (GAS)		150	82,283	73.9	84.4	95.2	11,013	GAS	884,907	1,024,000	906,145.0	2,555,328	3.11	2.89
POLK #3 CT (OIL)		159	203	0.2	84.4	60.7	12,571	LGT.OIL	437	5,829,600	2,547.1	55,749	27.46	127.57
POLK #3 TOTAL		**150**	**82,486**	**73.9**	**84.4**	**95.2**	**11,016**	-	-	-	**908,692.1**	**2,611,077**	**3.17**	-
POLK #4 TOTAL		**150**	**96,175**	**86.2**	**100.0**	**97.9**	**10,835**	GAS	**1,017,643**	**1,024,000**	**1,042,066.0**	**2,938,628**	**3.06**	**2.89**
POLK #5 TOTAL		**150**	**96,160**	**86.2**	**100.0**	**97.9**	**10,867**	GAS	**1,020,444**	**1,024,000**	**1,044,935.0**	**2,946,716**	**3.06**	**2.89**
POLK #2 CC TOTAL		**1,061**	**559,597**	**70.9**	**91.4**	**70.9**	**6,990**	GAS	-	-	**3,911,793.8**	**11,080,152**	**1.98**	-
POLK STATION TOTAL		**1,296**	**593,282**	**61.5**	**79.8**	**61.5**	**7,096**	-	-	-	**4,209,881.8**	**11,920,760**	**2.01**	-

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: May 2020

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP-ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
BAYSIDE ST 1	233	119,451	68.9	97.3	68.9	-		-	-	-	-	-	-
BAYSIDE CT1A	156	67,878	58.5	93.2	81.1	11,424	GAS	757,243	1,024,000	775,417.2	2,186,675	3.22	2.89
BAYSIDE CT1B	156	77,253	66.6	100.0	80.3	11,453	GAS	864,058	1,024,000	884,795.2	2,495,122	3.23	2.89
BAYSIDE CT1C	156	75,077	64.7	98.7	80.2	11,183	GAS	819,899	1,024,000	839,576.3	2,367,605	3.15	2.89
BAYSIDE UNIT 1 TOTAL	**701**	**339,659**	**65.1**	**97.3**	**65.1**	**7,360**	**GAS**	**2,441,200**	**1,024,000**	**2,499,788.8**	**7,049,402**	**2.08**	**2.89**
BAYSIDE ST 2	305	127,587	56.2	83.3	56.2	-		-	-	-	-	-	-
BAYSIDE CT2A	156	86,540	74.6	100.0	81.1	11,148	GAS	942,140	1,024,000	964,751.9	2,720,599	3.14	2.89
BAYSIDE CT2B	156	61,071	52.6	100.0	81.2	11,278	GAS	672,640	1,024,000	688,783.1	1,942,369	3.18	2.89
BAYSIDE CT2C	156	33,772	29.1	46.1	79.0	11,536	GAS	380,447	1,024,000	389,578.2	1,098,609	3.25	2.89
BAYSIDE CT2D	156	57,328	49.4	89.8	81.8	11,456	GAS	641,343	1,024,000	656,735.0	1,851,993	3.23	2.89
BAYSIDE UNIT 2 TOTAL	**929**	**366,298**	**53.0**	**83.8**	**53.0**	**7,371**	**GAS**	**2,636,570**	**1,024,000**	**2,699,848.1**	**7,613,570**	**2.08**	**2.89**
BAYSIDE UNIT 3 TOTAL	**56**	**1,190**	**2.9**	**100.0**	**91.5**	**10,759**	**GAS**	**12,503**	**1,024,000**	**12,802.9**	**36,104**	**3.03**	**2.89**
BAYSIDE UNIT 4 TOTAL	**56**	**1,815**	**4.4**	**100.0**	**96.8**	**10,534**	**GAS**	**18,673**	**1,024,000**	**19,119.8**	**53,918**	**2.97**	**2.89**
BAYSIDE UNIT 5 TOTAL	**56**	**1,873**	**4.5**	**96.2**	**89.1**	**10,840**	**GAS**	**19,828**	**1,024,000**	**20,303.7**	**57,256**	**3.06**	**2.89**
BAYSIDE UNIT 6 TOTAL	**56**	**887**	**2.1**	**100.0**	**92.6**	**10,612**	**GAS**	**9,192**	**1,024,000**	**9,412.7**	**26,544**	**2.99**	**2.89**
BAYSIDE STATION TOTAL	**1,854**	**711,722**	**51.6**	**90.7**	**51.6**	**7,392**	**GAS**	**5,137,966**	**1,024,000**	**5,261,276.0**	**14,836,794**	**2.08**	**2.89**
SYSTEM	**5,227**	**1,443,877**	**37.1**	**79.0**	**53.0**	**6,691**	**-**	**-**	**-**	**9,661,260.1**	**27,707,925**	**1.92**	**-**

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE
CC = COMBINED CYCLE
ST = STEAM TURBINE

Footnotes:
[1] As burned fuel cost system total includes ignition
[2] Fuel burned (MM BTU) system total excludes ignition
[3] Station Service
[4] Consists of fixed costs
[5] Big Bend Station Total net heat rate includes BB units 1, 3, and 4, all station service, causing the high heat rate. Excluding those units would produce a heat rate of 12,029.

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: June 2020

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR	1.6	238	20.7	-	43.6	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.4	3,834	27.4	-	50.2	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.4	190	18.8	-	33.9	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.3	13,513	26.7	-	50.5	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.4	14,952	27.9	-	52.9	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.5	13,692	25.5	-	51.2	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	61.1	11,758	26.7	-	50.8	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	55.4	9,825	24.6	-	46.2	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.5	6,402	23.7	-	41.9	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.5	8,466	23.8	-	44.5	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.8	15,246	-	-	-	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.5	16,368	30.5	-	55.9	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	**594.4**	**114,484**	**26.8**	-	**47.3**	-	**SOLAR**	-	-	-	-	-	-
BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BIG BEND #2 TOTAL	**340**	**18,448**	**7.5**	**52.6**	**42.4**	**13,146**	**GAS**	**237,536**	**1,021,000**	**242,524.7**	**601,960**	**3.26**	**2.53**
B.B.#3 (COAL)	395	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	345	85,306	34.3	31.6	51.5	-	GAS	1,052,018	1,021,000	1,074,110.3	2,666,003	3.13	2.53
BIG BEND #3 TOTAL	**345**	**85,306**	**34.3**	**31.6**	**51.5**	**12,591**	-	-	-	**1,074,110.3**	**2,666,003**	**3.13**	-
B.B.#4 (COAL)	437	78,044	24.8	100.0	51.5	-	COAL	41,559	22,436,013	932,418.3	2,645,478	3.39	63.66
B.B.#4 (GAS)	185	28,634	21.5	100.0	66.1	-	GAS	340,893	1,021,000	348,052.0	863,884	3.02	2.53
BIG BEND #4 TOTAL	**437**	**106,678**	**33.9**	**31.6**	**42.0**	**12,003**	-	-	-	**1,280,470.3**	**3,509,362**	**3.29**	-
B.B. IGNITION	-	-	-	-	-	-	GAS	31,613	1,021,000	32,276.9	80,113	-	2.53
BIG BEND CT #4 TOTAL	**56**	**495**	**1.2**	**89.3**	**83.0**	**15,221**	**GAS**	**7,379**	**1,021,000**	**7,534.2**	**18,700**	**3.78**	**2.53**
BIG BEND STATION TOTAL	**1,178**	**210,927**	**24.9**	**46.8**	**30.8**	**12,349**		-	-	**2,604,639.4**	**6,876,138**	**3.26**	-
POLK #1 GASIFIER	220	0	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	162	96,483	82.6	96.0	82.9	11,076	GAS	1,046,690	1,021,000	1,068,670.0	2,652,500	2.03	2.53
POLK #1 ST	48	34,038	98.4	99.8	98.7	-	-	-	-	-	-	-	-
POLK #1 TOTAL	**210**	**130,521**	**86.2**	**91.7**	**86.4**	**8,188**	-	-	-	**1,068,670.0**	**2,652,500**	**2.03**	-
POLK #2 ST DUCT FIRING	120	5,707	6.6	-	77.8	8,400	GAS	46,950	1,021,000	47,936.0	118,980	2.08	2.53
POLK #2 ST W/O DUCT FIRING	341	183,200	74.6	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	**461**	**188,907**	**56.9**	**96.4**	**77.8**	-	**GAS**	-	-	**47,936.0**	**118,980**	**0.06**	-
POLK #2 CT (GAS)	150	72,738	56.8	61.7	91.6	11,223	GAS	799,580	1,021,000	816,371.0	2,026,279	2.79	2.53
POLK #2 CT (OIL) (3)	159	153	0.1	61.7	37.0	17,615	LGT.OIL	463	5,829,600	2,696.0	68,108	44.52	147.10
POLK #2 TOTAL	**150**	**72,891**	**56.9**	**61.7**	**91.6**	**11,237**	-	-	-	**819,067.0**	**2,094,387**	**2.87**	-
POLK #3 CT (GAS)	150	82,050	76.7	99.8	96.1	11,057	GAS	888,567	1,021,000	907,227.0	2,251,789	2.74	2.53
POLK #3 CT (OIL) (3)	159	98	0.1	99.8	32.4	17,615	LGT.OIL	296	5,829,600	1,726.2	43,542	44.43	147.10
POLK #3 TOTAL	**150**	**82,148**	**76.7**	**99.8**	**96.1**	**11,065**	-	-	-	**908,953.2**	**2,295,331**	**2.79**	-
POLK #4 TOTAL	**150**	**82,829**	**81.4**	**99.9**	**94.6**	**10,786**	GAS	**874,998**	**1,021,000**	**893,373.0**	**2,217,403**	**2.68**	**2.53**
POLK #5 TOTAL	**150**	**87,909**	**86.2**	**100.0**	**97.9**	**10,898**	GAS	**938,321**	**1,021,000**	**958,026.0**	**2,377,875**	**2.70**	**2.53**
POLK #2 CC TOTAL	**1,061**	**514,684**	**67.4**	**82.8**	**78.3**	**7,048**	GAS	-	-	**3,627,355.2**	**9,103,976**	**1.77**	-
POLK STATION TOTAL	**1,271**	**645,205**	**69.1**	**84.4**	**69.4**	**7,278**	-	-	-	**4,696,025.2**	**11,756,476**	**1.82**	-

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SCHEDULE A4
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: June 2020

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
BAYSIDE ST 1	233	103,621	61.8	98.7	61.8	-		-	-	-	-	-	-
BAYSIDE CT1A	156	85,904	76.5	100.0	76.5	12,260	GAS	1,031,521	1,021,000	1,053,182.6	2,614,060	3.04	2.53
BAYSIDE CT1B	156	58,226	51.8	100.0	78.1	12,162	GAS	693,559	1,021,000	708,124.2	1,757,602	3.02	2.53
BAYSIDE CT1C	156	42,467	37.8	96.2	77.4	11,912	GAS	495,443	1,021,000	505,846.8	1,255,543	2.96	2.53
BAYSIDE UNIT 1 TOTAL	**701**	**290,218**	**57.5**	**98.7**	**57.5**	**7,812**	**GAS**	**2,220,523**	**1,021,000**	**2,267,153.7**	**5,627,205**	**1.94**	**2.53**
BAYSIDE ST 2	305	154,276	70.2	97.9	70.2	-		-	-	-	-	-	-
BAYSIDE CT2A	156	86,414	76.9	100.0	78.9	11,815	GAS	999,961	1,021,000	1,020,959.8	2,534,080	2.93	2.53
BAYSIDE CT2B	156	67,032	59.6	97.4	78.1	11,825	GAS	776,375	1,021,000	792,678.6	1,967,474	2.94	2.53
BAYSIDE CT2C	156	56,551	50.3	97.1	79.2	12,084	GAS	669,306	1,021,000	683,361.0	1,696,141	3.00	2.53
BAYSIDE CT2D	156	67,077	59.6	96.7	78.1	12,098	GAS	794,790	1,021,000	811,480.6	2,014,140	3.00	2.53
BAYSIDE UNIT 2 TOTAL	**929**	**431,350**	**64.4**	**97.8**	**64.4**	**7,670**	**GAS**	**3,240,432**	**1,021,000**	**3,308,479.9**	**8,211,835**	**1.90**	**2.53**
BAYSIDE UNIT 3 TOTAL	**56**	**537**	**1.3**	**67.6**	**92.6**	**10,814**	**GAS**	**5,688**	**1,021,000**	**5,807.0**	**14,413**	**2.68**	**2.53**
BAYSIDE UNIT 4 TOTAL	**56**	**255**	**0.6**	**72.4**	**82.6**	**11,338**	**GAS**	**2,832**	**1,021,000**	**2,891.3**	**7,176**	**2.81**	**2.53**
BAYSIDE UNIT 5 TOTAL	**56**	**710**	**1.8**	**94.3**	**87.3**	**12,865**	**GAS**	**8,946**	**1,021,000**	**9,134.0**	**22,671**	**3.19**	**2.53**
BAYSIDE UNIT 6 TOTAL	**56**	**722**	**1.8**	**95.9**	**91.2**	**10,704**	**GAS**	**7,569**	**1,021,000**	**7,728.0**	**19,182**	**2.66**	**2.53**
BAYSIDE STATION TOTAL	**1,854**	**723,792**	**54.2**	**96.3**	**54.2**	**7,739**	**GAS**	**5,485,989**	**1,021,000**	**5,601,193.8**	**13,902,482**	**1.92**	**2.53**
SYSTEM	**4,897**	**1,694,408**	**48.0**	**79.2**	**53.4**	**7,614**	**-**	**-**	**-**	**12,901,858.4**	**32,535,096**	**1.92**	**-**

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE
CC = COMBINED CYCLE
ST = STEAM TURBINE

Footnotes:
(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) Includes May 2020 adjustment to as burned fuel cost of $4.74 to Polk 2 and $610.66 to Polk 3.

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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2020

(A) PLANT/UNIT		(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR		1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR		19.3	290	2.0	-	2.0	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR		1.5	4,290	384.4	-	384.4	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR		70.1	16,400	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR		74.2	17,010	30.8	-	30.8	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR		74.3	17,370	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR		60.8	13,690	30.3	-	30.3	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR		54.8	12,500	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR		37.4	8,520	30.6	-	30.6	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR		49.4	10,850	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR		74.7	16,420	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR		74.3	17,400	31.5	-	31.5	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL	(3)	**592.4**	**135,030**	**30.6**	**-**	**30.6**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL		**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
15. BIG BEND #2 TOTAL		**340**	**5,320**	**2.1**	**84.2**	**43.5**	**13,077**	**GAS**	**67,670**	**1,028,077**	**69,570.0**	**219,999**	**4.14**	**3.25**
16. B.B.#3 (GAS)		345	19,630	7.6	-	-	-	GAS	222,650	1,028,026	228,890.0	723,848	3.69	3.25
17. B.B.#3 (COAL)		395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL		**395**	**19,630**	**6.7**	**88.0**	**51.8**	**11,660**		**-**	**-**	**228,890.0**	**723,848**	**3.69**	**-**
19. B.B.#4 (GAS)		155	5,490	4.8	-	-	-	GAS	68,490	1,028,033	70,410.0	222,665	4.06	3.25
20. B.B.#4 (COAL)		422	104,340	33.2	-	-	-	COAL	59,450	22,501,598	1,337,720.0	4,219,114	4.04	70.97
21. BIG BEND #4 TOTAL		**422**	**109,830**	**35.0**	**86.7**	**40.3**	**12,821**		**-**	**-**	**1,408,130.0**	**4,441,779**	**4.04**	**-**
22. B.B. IGNITION		-	-	-	-	-	-	GAS	10,850	-	11,160.0	35,274	-	3.25
23. B.B.C.T.#4 TOTAL		**56**	**270**	**0.6**	**98.2**	**96.4**	**11,444**	**GAS**	**3,010**	**1,026,578**	**3,090.0**	**9,786**	**3.62**	**3.25**
24. BIG BEND STATION TOTAL		**1,213**	**135,050**	**15.0**	**86.9**	**41.8**	**12,660**	**-**	**-**	**-**	**1,709,680.0**	**5,430,686**	**4.02**	**-**
25. POLK #1 GASIFIER		220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)		210	26,300	16.8	-	82.4	8,879	GAS	227,160	1,027,954	233,510.0	738,510	2.81	3.25
27. POLK #1 TOTAL		**220**	**26,300**	**16.1**	**94.2**	**82.4**	**8,879**	**-**	**-**	**-**	**233,510.0**	**738,510**	**2.81**	**-**
28. POLK #2 ST DUCT FIRING		120	10,820	12.1	-	67.8	8,273	GAS	87,070	1,028,023	89,510.0	283,070	2.62	3.25
29. POLK #2 ST W/O DUCT FIRING		341	655,123	-	-	-	-	GAS	4,396,675	1,028,020	4,519,871.4	14,293,847	2.18	3.25
30. POLK #2 ST TOTAL		**461**	**665,943**	**194.2**	**-**	**166.6**	**6,922**	**GAS**	**-**	**-**	**4,609,381.4**	**14,576,917**	**2.19**	**-**
31. POLK #2 CT (GAS)		150	1,440	1.3	-	96.0	10,854	GAS	15,200	1,028,289	15,630.0	49,417	3.43	3.25
32. POLK #2 CT (OIL)		159	1,329	1.1	-	10.6	10,996	LGT OIL	2,493	5,862,134	14,614.3	336,794	25.34	135.10
33. POLK #2 TOTAL	(4)	**150**	**2,769**	**2.5**	**-**	**19.7**	**10,922**	**-**	**-**	**-**	**30,244.3**	**386,211**	**13.95**	**-**
34. POLK #3 CT (GAS)		150	1,440	1.3	-	96.0	10,854	GAS	15,200	1,028,289	15,630.0	49,416	3.43	3.25
35. POLK #3 CT (OIL)		159	1,329	1.1	-	94.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	336,794	25.34	135.10
36. POLK #3 TOTAL	(4)	**150**	**2,769**	**2.5**	**-**	**95.2**	**10,922**	**-**	**-**	**-**	**30,244.3**	**386,210**	**13.95**	**-**
37. POLK #4 CT (GAS) TOTAL	(4)	**150**	**1,440**	**1.3**	**-**	**96.0**	**10,854**	**GAS**	**15,200**	**1,028,289**	**15,630.0**	**49,416**	**3.43**	**3.25**
38. POLK #5 CT (GAS) TOTAL	(4)	**150**	**900**	**0.8**	**-**	**100.0**	**10,689**	**GAS**	**9,350**	**1,028,877**	**9,620.0**	**30,397**	**3.38**	**3.25**
39. POLK #2 CC TOTAL		**1,061**	**673,821**	**85.4**	**97.5**	**151.0**	**6,968**	**-**	**-**	**-**	**4,695,120.0**	**15,429,151**	**2.29**	**-**
40. POLK STATION TOTAL		**1,281**	**700,121**	**73.5**	**96.9**	**141.8**	**7,040**	**-**	**-**	**-**	**4,928,630.0**	**16,167,661**	**2.31**	**-**
41. BAYSIDE #1		720	410,980	76.7	97.2	78.7	7,325	GAS	2,928,550	1,028,000	3,010,550.0	9,520,887	2.32	3.25
42. BAYSIDE #2		954	398,470	56.1	97.4	57.6	7,550	GAS	2,926,580	1,027,995	3,008,510.0	9,514,482	2.39	3.25
43. BAYSIDE #3		56	580	1.4	98.6	86.3	11,948	GAS	6,730	1,029,718	6,930.0	21,880	3.77	3.25
44. BAYSIDE #4		56	440	1.1	98.6	87.3	11,932	GAS	5,100	1,029,412	5,250.0	16,580	3.77	3.25
45. BAYSIDE #5		56	530	1.3	76.3	86.0	12,057	GAS	6,220	1,027,331	6,390.0	20,222	3.82	3.25
46. BAYSIDE #6		56	420	1.0	54.1	83.3	12,310	GAS	5,030	1,027,833	5,170.0	16,353	3.89	3.25
47. BAYSIDE STATION TOTAL		**1,898**	**811,420**	**57.5**	**95.5**	**66.7**	**7,447**	**GAS**	**5,878,210**	**1,028,000**	**6,042,800.0**	**19,110,404**	**2.36**	**3.25**
48. SYSTEM TOTAL		**4,984**	**1,781,621**	**48.0**	**82.4**	**95.9**	**7,118**	**-**	**-**	**-**	**12,681,110.0**	**40,708,751**	**2.28**	**-**

LEGEND:
B.B. = BIG BEND **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM TURBINE**

(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) AC rating
(4) In Simple Cycle Mode

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	270	1.9	-	1.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,210	377.2	-	377.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	15,830	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,410	29.7	-	29.7	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	16,780	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,220	29.2	-	29.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,080	29.6	-	29.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,380	30.1	-	30.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,470	28.5	-	28.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	15,920	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	16,840	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**592.4**	**130,700**	**29.7**	**-**	**29.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
15. BIG BEND #2 TOTAL	**340**	**12,780**	**5.1**	**84.2**	**39.2**	**13,549**	**GAS**	**168,440**	**1,028,022**	**173,160.0**	**563,844**	**4.41**	**3.35**
16. B.B.#3 (GAS)	345	27,840	10.8	-	-	-	GAS	320,370	1,027,999	329,340.0	1,072,422	3.85	3.35
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**395**	**27,840**	**9.5**	**88.0**	**48.9**	**11,830**		**-**	**-**	**329,340.0**	**1,072,422**	**3.85**	**-**
19. B.B.#4 (GAS)	155	5,690	4.9	-	-	-	GAS	70,200	1,028,063	72,170.0	234,991	4.13	3.35
20. B.B.#4 (COAL)	422	108,120	34.4	-	-	-	COAL	60,940	22,500,328	1,371,170.0	4,312,681	3.99	70.77
21. BIG BEND #4 TOTAL	**422**	**113,810**	**36.2**	**86.7**	**41.7**	**12,682**		**-**	**-**	**1,443,340.0**	**4,547,672**	**4.00**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	20,870	-	21,450.0	69,861	-	3.35
23. B.B.C.T.#4 TOTAL	**56**	**1,340**	**3.2**	**98.2**	**82.5**	**11,799**	**GAS**	**15,380**	**1,027,958**	**15,810.0**	**51,484**	**3.84**	**3.35**
24. BIG BEND STATION TOTAL	**1,213**	**155,770**	**17.3**	**86.9**	**42.8**	**12,593**	**-**	**-**	**-**	**1,961,650.0**	**6,305,283**	**4.05**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	29,690	19.0	-	83.2	8,862	GAS	255,950	1,027,974	263,110.0	856,779	2.89	3.35
27. POLK #1 TOTAL	**220**	**29,690**	**18.1**	**94.2**	**83.2**	**8,862**	**-**	**-**	**-**	**263,110.0**	**856,779**	**2.89**	**-**
28. POLK #2 ST DUCT FIRING	120	11,520	12.9	-	71.6	8,271	GAS	92,680	1,028,054	95,280.0	310,241	2.69	3.35
29. POLK #2 ST W/O DUCT FIRING	341	648,973	-	-	-	-	GAS	4,356,285	1,028,021	4,478,351.4	14,582,438	2.25	3.35
30. POLK #2 ST TOTAL	**461**	**660,493**	**192.6**	**-**	**165.1**	**6,925**	**GAS**	**-**	**-**	**4,573,631.4**	**14,892,679**	**2.25**	**-**
31. POLK #2 CT (GAS)	150	1,350	1.2	-	100.0	10,674	GAS	14,020	1,027,817	14,410.0	46,932	3.48	3.35
32. POLK #2 CT (OIL)	159	1,329	1.1	-	10.1	10,996	LGT OIL	2,493	5,862,134	14,614.3	304,333	22.90	122.08
33. POLK #2 TOTAL [4]	**150**	**2,679**	**2.4**	**-**	**18.5**	**10,834**	**-**	**-**	**-**	**29,024.3**	**351,265**	**13.11**	**-**
34. POLK #3 CT (GAS)	150	1,500	1.3	-	100.0	10,733	GAS	15,660	1,028,097	16,100.0	52,421	3.49	3.35
35. POLK #3 CT (OIL)	159	1,329	1.1	-	94.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	304,332	22.90	122.07
36. POLK #3 TOTAL [4]	**150**	**2,829**	**2.5**	**-**	**97.3**	**10,857**	**-**	**-**	**-**	**30,714.3**	**356,753**	**12.61**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**1,500**	**1.3**	**-**	**100.0**	**10,727**	**GAS**	**15,660**	**1,027,458**	**16,090.0**	**52,421**	**3.49**	**3.35**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**830**	**0.7**	**-**	**92.2**	**11,024**	**GAS**	**8,900**	**1,028,090**	**9,150.0**	**29,792**	**3.59**	**3.35**
39. POLK #2 CC TOTAL	**1,061**	**668,331**	**84.7**	**97.5**	**149.1**	**6,971**	**-**	**-**	**-**	**4,658,610.0**	**15,682,910**	**2.35**	**-**
40. POLK STATION TOTAL	**1,281**	**698,021**	**73.2**	**96.9**	**139.5**	**7,051**	**-**	**-**	**-**	**4,921,720.0**	**16,539,689**	**2.37**	**-**
41. BAYSIDE #1	720	420,670	78.5	97.2	80.7	7,312	GAS	2,992,160	1,027,996	3,075,930.0	10,016,100	2.38	3.35
42. BAYSIDE #2	954	443,460	62.5	97.4	64.2	7,481	GAS	3,226,960	1,028,005	3,317,330.0	10,802,080	2.44	3.35
43. BAYSIDE #3	56	1,380	3.3	98.6	85.0	11,797	GAS	15,840	1,027,778	16,280.0	53,024	3.84	3.35
44. BAYSIDE #4	56	1,010	2.4	98.6	82.0	11,980	GAS	11,780	1,027,165	12,100.0	39,433	3.90	3.35
45. BAYSIDE #5	56	1,640	3.9	98.6	83.7	11,780	GAS	18,790	1,028,206	19,320.0	62,899	3.84	3.35
46. BAYSIDE #6	56	1,470	3.5	98.6	87.5	11,599	GAS	16,590	1,027,728	17,050.0	55,534	3.78	3.35
47. BAYSIDE STATION TOTAL	**1,898**	**869,630**	**61.6**	**97.5**	**71.4**	**7,426**	**GAS**	**6,282,120**	**1,027,999**	**6,458,010.0**	**21,029,070**	**2.42**	**3.35**
48. SYSTEM TOTAL	**4,984**	**1,854,121**	**50.0**	**83.2**	**97.3**	**7,196**	**-**	**-**	**-**	**13,341,380.0**	**43,874,042**	**2.37**	**-**

LEGEND:
B.B. = BIG BEND **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM TURBINE**

[1] As burned fuel cost system total includes ignition
[2] Fuel burned (MM BTU) system total excludes ignition
[3] AC rating
[4] In Simple Cycle Mode

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Exhibit No. MAS-2
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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	260	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	220	1.6	-	1.6	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,500	324.1	-	324.1	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,770	27.3	-	27.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,270	26.7	-	26.7	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,430	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,490	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,510	26.6	-	26.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,780	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	9,100	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	13,780	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,480	27.1	-	27.1	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**1.6**	**112,590**	**9773.4**	**-**	**9,773.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
15. BIG BEND #2 TOTAL	**340**	**12,040**	**4.9**	**84.2**	**36.5**	**13,900**	**GAS**	**162,800**	**1,028,010**	**167,360.0**	**556,896**	**4.63**	**3.42**
16. B.B.#3 (GAS)	345	33,600	13.5	-	-	-	GAS	382,210	1,027,995	392,910.0	1,307,439	3.89	3.42
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**395**	**33,600**	**11.8**	**88.0**	**51.2**	**11,694**		**-**	**-**	**392,910.0**	**1,307,439**	**3.89**	**-**
19. B.B.#4 (GAS)	155	5,670	5.1	-	-	-	GAS	69,320	1,027,986	71,260.0	237,125	4.18	3.42
20. B.B.#4 (COAL)	422	107,800	35.5	-	-	-	COAL	60,180	22,499,501	1,354,020.0	4,246,528	3.94	70.56
21. BIG BEND #4 TOTAL	**422**	**113,470**	**37.3**	**86.7**	**43.0**	**12,561**		**-**	**-**	**1,425,280.0**	**4,483,653**	**3.95**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	22,960	-	23,600.0	78,540	-	3.42
23. B.B.C.T.#4 TOTAL	**56**	**1,000**	**2.5**	**98.2**	**99.2**	**11,410**	**GAS**	**11,100**	**1,027,928**	**11,410.0**	**37,970**	**3.80**	**3.42**
24. BIG BEND STATION TOTAL	**1,213**	**160,110**	**18.3**	**86.9**	**44.1**	**12,472**	**-**	**-**	**-**	**1,996,960.0**	**6,464,498**	**4.04**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	35,170	23.3	-	84.2	8,844	GAS	302,570	1,028,027	311,050.0	1,035,011	2.94	3.42
27. POLK #1 TOTAL	**220**	**35,170**	**22.2**	**94.2**	**84.2**	**8,844**	**-**	**-**	**-**	**311,050.0**	**1,035,011**	**2.94**	**-**
28. POLK #2 ST DUCT FIRING	120	13,230	15.3	-	62.6	8,271	GAS	106,440	1,028,091	109,430.0	364,103	2.75	3.42
29. POLK #2 ST W/O DUCT FIRING	341	486,529	-	-	-	-	GAS	3,262,864	1,028,025	3,354,304.3	11,161,390	2.29	3.42
30. POLK #2 ST TOTAL	**461**	**499,759**	**150.6**	**-**	**122.4**	**6,931**	**GAS**	**-**	**-**	**3,463,734.3**	**11,525,493**	**2.31**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	1,286	1.1	-	9.4	10,998	LGT OIL	2,412	5,863,557	14,142.9	269,689	20.97	111.81
33. POLK #2 TOTAL [4]	**150**	**1,286**	**1.2**	**-**	**9.4**	**10,998**	**-**	**-**	**-**	**14,142.9**	**269,689**	**20.97**	**-**
34. POLK #3 CT (GAS)	150	1,500	1.4	-	100.0	10,727	GAS	15,660	1,027,458	16,090.0	53,569	3.57	3.42
35. POLK #3 CT (OIL)	159	1,286	1.1	-	94.4	10,998	LGT OIL	2,412	5,863,557	14,142.9	269,689	20.97	111.81
36. POLK #3 TOTAL [4]	**150**	**2,786**	**2.6**	**-**	**97.3**	**10,852**	**-**	**-**	**-**	**30,232.9**	**323,258**	**11.60**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**1,500**	**1.4**	**-**	**100.0**	**10,727**	**GAS**	**15,660**	**1,027,458**	**16,090.0**	**53,569**	**3.57**	**3.42**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**1,350**	**1.3**	**-**	**100.0**	**10,733**	**GAS**	**14,100**	**1,027,660**	**14,490.0**	**48,232**	**3.57**	**3.42**
39. POLK #2 CC TOTAL	**1,061**	**506,681**	**66.3**	**97.5**	**111.8**	**6,984**	**-**	**-**	**-**	**3,538,690.1**	**12,220,241**	**2.41**	**-**
40. POLK STATION TOTAL	**1,281**	**541,851**	**58.7**	**96.9**	**107.3**	**7,105**	**-**	**-**	**-**	**3,849,740.1**	**13,255,252**	**2.45**	**-**
41. BAYSIDE #1	720	413,940	79.8	97.2	82.1	7,306	GAS	2,942,000	1,027,998	3,024,370.0	10,063,800	2.43	3.42
42. BAYSIDE #2	954	449,550	65.4	97.4	67.2	7,454	GAS	3,259,620	1,027,997	3,350,880.0	11,150,293	2.48	3.42
43. BAYSIDE #3	56	1,260	3.1	98.6	83.3	11,968	GAS	14,680	1,027,248	15,080.0	50,216	3.99	3.42
44. BAYSIDE #4	56	1,120	2.8	98.6	87.0	11,884	GAS	12,940	1,028,594	13,310.0	44,264	3.95	3.42
45. BAYSIDE #5	56	1,810	4.5	98.6	87.4	11,740	GAS	20,680	1,027,563	21,250.0	70,741	3.91	3.42
46. BAYSIDE #6	56	1,660	4.1	98.6	87.2	11,771	GAS	19,000	1,028,421	19,540.0	64,994	3.92	3.42
47. BAYSIDE STATION TOTAL	**1,898**	**869,340**	**63.6**	**97.5**	**73.7**	**7,413**	**GAS**	**6,268,920**	**1,027,997**	**6,444,430.0**	**21,444,308**	**2.47**	**3.42**
48. SYSTEM TOTAL	**4,394**	**1,683,891**	**53.2**	**94.4**	**90.1**	**7,299**	**-**	**-**	**-**	**12,291,130.1**	**41,164,058**	**2.44**	**-**

LEGEND:
B.B. = BIG BEND **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM TURBINE**

[1] **As burned fuel cost system total includes ignition**
[2] **Fuel burned (MM BTU) system total excludes ignition**
[3] **AC rating**
[4] **In Simple Cycle Mode**

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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	230	1.6	-	1.6	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,620	324.4	-	324.4	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,610	26.1	-	26.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,110	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,090	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,340	25.1	-	25.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,380	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	7,160	25.7	-	25.7	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,990	24.5	-	24.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	14,310	25.7	-	25.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,140	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**592.4**	**112,270**	**25.5**	**-**	**25.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
15. BIG BEND #2 TOTAL	**340**	**31,010**	**12.3**	**84.2**	**41.8**	**13,243**	**GAS**	**399,490**	**1,028,011**	**410,680.0**	**1,391,660**	**4.49**	**3.48**
16. B.B.#3 (GAS)	345	47,060	18.3	-	-	-	GAS	540,640	1,028,004	555,780.0	1,883,369	4.00	3.48
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**395**	**47,060**	**16.0**	**82.3**	**49.2**	**11,810**		**-**	**-**	**555,780.0**	**1,883,369**	**4.00**	**-**
19. B.B.#4 (GAS)	155	2,640	2.3	-	-	-	GAS	33,310	1,027,920	34,240.0	116,038	4.40	3.48
20. B.B.#4 (COAL)	422	50,220	16.0	-	-	-	COAL	28,920	22,497,234	650,620.0	2,034,424	4.05	70.35
21. BIG BEND #4 TOTAL	**422**	**52,860**	**16.8**	**86.7**	**39.0**	**12,956**		**-**	**-**	**684,860.0**	**2,150,462**	**4.07**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	50,930	-	52,350.0	177,419	-	3.48
23. B.B.C.T.#4 TOTAL	**56**	**1,520**	**3.6**	**98.2**	**59.0**	**13,217**	**GAS**	**19,550**	**1,027,621**	**20,090.0**	**68,104**	**4.48**	**3.48**
24. BIG BEND STATION TOTAL	**1,213**	**132,450**	**14.7**	**85.1**	**43.0**	**12,619**	**-**	**-**	**-**	**1,671,410.0**	**5,671,014**	**4.28**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	25,210	16.1	-	83.9	8,846	GAS	216,950	1,027,933	223,010.0	755,765	3.00	3.48
27. POLK #1 TOTAL	**220**	**25,210**	**15.4**	**63.8**	**83.9**	**8,846**	**-**	**-**	**-**	**223,010.0**	**755,765**	**3.00**	**-**
28. POLK #2 ST DUCT FIRING	120	15,970	17.9	-	57.4	8,272	GAS	128,510	1,028,013	132,110.0	447,676	2.80	3.48
29. POLK #2 ST W/O DUCT FIRING	341	502,281	-	-	-	-	GAS	3,369,144	1,028,022	3,463,555.7	11,736,717	2.34	3.48
30. POLK #2 ST TOTAL	**461**	**518,251**	**151.1**	**-**	**116.4**	**6,938**	**GAS**	**-**	**-**	**3,595,665.7**	**12,184,393**	**2.35**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	1,200	1.0	-	8.4	11,000	LGT OIL	2,251	5,864,060	13,200.0	237,867	19.82	105.67
33. POLK #2 TOTAL [4]	**150**	**1,200**	**1.1**	**-**	**8.4**	**11,000**	**-**	**-**	**-**	**13,200.0**	**237,867**	**19.82**	**-**
34. POLK #3 CT (GAS)	150	1,200	1.1	-	80.0	11,383	GAS	13,290	1,027,840	13,660.0	46,297	3.86	3.48
35. POLK #3 CT (OIL)	159	1,329	1.1	-	94.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	263,441	19.82	105.67
36. POLK #3 TOTAL [4]	**150**	**2,529**	**2.3**	**-**	**87.0**	**11,180**	**-**	**-**	**-**	**28,274.3**	**309,738**	**12.25**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**610**	**0.5**	**-**	**81.3**	**11,328**	**GAS**	**6,720**	**1,028,274**	**6,910.0**	**23,410**	**3.84**	**3.48**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**522,590**	**66.2**	**97.5**	**106.8**	**6,973**	**-**	**-**	**-**	**3,644,050.0**	**12,755,408**	**2.44**	**-**
40. POLK STATION TOTAL	**1,281**	**547,800**	**57.5**	**91.7**	**104.1**	**7,059**	**-**	**-**	**-**	**3,867,060.0**	**13,511,173**	**2.47**	**-**
41. BAYSIDE #1	720	326,570	61.0	97.2	62.9	7,432	GAS	2,361,100	1,027,995	2,427,200.0	8,225,105	2.52	3.48
42. BAYSIDE #2	954	403,170	56.8	97.4	58.7	7,540	GAS	2,956,930	1,027,999	3,039,720.0	10,300,733	2.55	3.48
43. BAYSIDE #3	56	3,760	9.0	98.6	72.2	12,399	GAS	45,360	1,027,778	46,620.0	158,016	4.20	3.48
44. BAYSIDE #4	56	2,360	5.7	98.6	66.9	12,754	GAS	29,300	1,027,304	30,100.0	102,069	4.32	3.48
45. BAYSIDE #5	56	4,740	11.4	98.6	71.7	12,414	GAS	57,240	1,027,952	58,840.0	199,401	4.21	3.48
46. BAYSIDE #6	56	4,120	9.9	98.6	72.1	12,449	GAS	49,900	1,027,856	51,290.0	173,831	4.22	3.48
47. BAYSIDE STATION TOTAL	**1,898**	**744,720**	**52.7**	**97.5**	**60.7**	**7,592**	**GAS**	**5,499,830**	**1,027,990**	**5,653,770.0**	**19,159,155**	**2.57**	**3.48**
48. SYSTEM TOTAL	**4,984**	**1,537,240**	**41.5**	**81.4**	**82.6**	**7,281**	**-**	**-**	**-**	**11,192,240.0**	**38,341,342**	**2.49**	**-**

LEGEND:
B.B. = BIG BEND **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM TURBINE**

[1] As burned fuel cost system total includes ignition
[2] Fuel burned (MM BTU) system total excludes ignition
[3] AC rating
[4] In Simple Cycle Mode

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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2020

(A) PLANT/UNIT	(B) NET CAPA- BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	270	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	180	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,980	275.9	-	275.9	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	10,170	20.1	-	20.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,540	19.7	-	19.7	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	12,070	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,450	19.3	-	19.3	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,740	19.6	-	19.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,060	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,730	18.9	-	18.9	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,830	22.0	-	22.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,120	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**592.4**	**89,140**	**20.9**	**-**	**20.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
15. BIG BEND #2 TOTAL	**340**	**36,710**	**15.0**	**84.2**	**38.3**	**13,670**	**GAS**	**488,160**	**1,028,003**	**501,830.0**	**1,843,787**	**5.02**	**3.78**
16. B.B.#3 (GAS)	345	63,370	25.5	-	-	-	GAS	732,210	1,027,997	752,710.0	2,765,567	4.36	3.78
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**395**	**63,370**	**22.3**	**64.5**	**48.3**	**11,878**		**-**	**-**	**752,710.0**	**2,765,567**	**4.36**	**-**
19. B.B.#4 (GAS)	155	2,090	1.9	-	-	-	GAS	26,330	1,027,725	27,060.0	99,449	4.76	3.78
20. B.B.#4 (COAL)	422	39,680	13.1	-	-	-	COAL	22,850	22,503,282	514,200.0	1,618,459	4.08	70.83
21. BIG BEND #4 TOTAL	**422**	**41,770**	**13.7**	**83.8**	**39.0**	**12,958**		**-**	**-**	**541,260.0**	**1,717,908**	**4.11**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	45,090	-	46,350.0	170,305	-	3.78
23. B.B.C.T.#4 TOTAL	**56**	**1,450**	**3.6**	**98.2**	**41.1**	**15,200**	**GAS**	**21,440**	**1,027,985**	**22,040.0**	**80,979**	**5.58**	**3.78**
24. BIG BEND STATION TOTAL	**1,213**	**143,300**	**16.4**	**78.3**	**42.4**	**12,686**	**-**	**-**	**-**	**1,817,840.0**	**6,578,545**	**4.59**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	90,440	59.8	-	83.5	8,744	GAS	769,250	1,028,001	790,790.0	2,905,467	3.21	3.78
27. POLK #1 TOTAL	**220**	**90,440**	**57.1**	**94.2**	**83.5**	**8,744**	**-**	**-**	**-**	**790,790.0**	**2,905,467**	**3.21**	**-**
28. POLK #2 ST DUCT FIRING	120	17,350	20.1	-	67.2	8,271	GAS	139,600	1,028,009	143,510.0	527,271	3.04	3.78
29. POLK #2 ST W/O DUCT FIRING	341	428,540	-	-	-	-	GAS	2,880,564	1,028,024	2,961,290.0	10,879,926	2.54	3.78
30. POLK #2 ST TOTAL	**461**	**445,890**	**134.3**	**-**	**119.9**	**6,963**	**GAS**	**-**	**-**	**3,104,800.0**	**11,407,197**	**2.56**	**-**
31. POLK #2 CT (GAS)	150	13,790	12.8	-	76.0	11,588	GAS	155,440	1,028,049	159,800.0	587,098	4.26	3.78
32. POLK #2 CT (OIL)	159	1,114	1.0	-	7.6	11,003	LGT OIL	2,091	5,861,836	12,257.1	211,374	18.97	101.09
33. POLK #2 TOTAL [4]	**150**	**14,904**	**13.8**	**-**	**45.5**	**11,544**	**-**	**-**	**-**	**172,057.1**	**798,472**	**5.36**	**-**
34. POLK #3 CT (GAS)	150	10,320	9.6	-	78.2	11,508	GAS	115,520	1,028,047	118,760.0	436,320	4.23	3.78
35. POLK #3 CT (OIL)	159	986	0.9	-	94.4	10,997	LGT OIL	1,849	5,864,197	10,842.9	186,912	18.96	101.09
36. POLK #3 TOTAL [4]	**150**	**11,306**	**10.5**	**-**	**79.4**	**11,463**	**-**	**-**	**-**	**129,602.9**	**623,232**	**5.51**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**3,400**	**3.1**	**-**	**87.2**	**11,247**	**GAS**	**37,200**	**1,027,957**	**38,240.0**	**140,505**	**4.13**	**3.78**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**130**	**0.1**	**-**	**86.7**	**11,846**	**GAS**	**1,500**	**1,026,667**	**1,540.0**	**5,666**	**4.36**	**3.78**
39. POLK #2 CC TOTAL	**1,061**	**475,630**	**62.3**	**89.4**	**101.9**	**7,246**	**-**	**-**	**-**	**3,446,240.0**	**12,975,072**	**2.73**	**-**
40. POLK STATION TOTAL	**1,281**	**566,070**	**61.4**	**90.2**	**96.1**	**7,485**	**-**	**-**	**-**	**4,237,030.0**	**15,880,539**	**2.81**	**-**
41. BAYSIDE #1	720	273,430	52.7	94.0	56.0	7,504	GAS	1,996,060	1,027,995	2,051,940.0	7,539,143	2.76	3.78
42. BAYSIDE #2	954	199,690	29.1	52.0	56.0	7,566	GAS	1,469,640	1,027,993	1,510,780.0	5,550,849	2.78	3.78
43. BAYSIDE #3	56	3,410	8.5	98.6	57.4	13,267	GAS	44,010	1,027,948	45,240.0	166,226	4.87	3.78
44. BAYSIDE #4	56	3,280	8.1	98.6	58.6	13,104	GAS	41,810	1,027,984	42,980.0	157,917	4.81	3.78
45. BAYSIDE #5	56	5,730	14.2	98.6	67.3	12,522	GAS	69,800	1,027,937	71,750.0	263,635	4.60	3.78
46. BAYSIDE #6	56	4,720	11.7	98.6	66.4	12,555	GAS	57,640	1,028,105	59,260.0	217,707	4.61	3.78
47. BAYSIDE STATION TOTAL	**1,898**	**490,260**	**35.9**	**73.4**	**56.2**	**7,714**	**GAS**	**3,678,960**	**1,027,994**	**3,781,950.0**	**13,895,477**	**2.83**	**3.78**
48. SYSTEM TOTAL	**4,984**	**1,288,770**	**35.9**	**70.2**	**80.5**	**7,633**	**-**	**-**	**-**	**9,836,820.0**	**36,354,561**	**2.82**	**-**

LEGEND:
B.B. = BIG BEND **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM TURBINE**

[1] **As burned fuel cost system total includes ignition**
[2] **Fuel burned (MM BTU) system total excludes ignition**
[3] **AC rating**
[4] **In Simple Cycle Mode**

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Exhibit No. MAS-2
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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	260	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	160	1.1	-	1.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,710	242.8	-	242.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	8,540	16.4	-	16.4	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	8,840	16.0	-	16.0	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	10,460	18.9	-	18.9	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	7,100	15.7	-	15.7	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	6,510	16.0	-	16.0	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,080	18.3	-	18.3	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	5,650	15.4	-	15.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	10,550	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	10,530	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**592.4**	**76,390**	**17.3**	**-**	**17.3**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
15. BIG BEND #2 TOTAL	**350**	**10,640**	**4.1**	**84.2**	**40.5**	**13,170**	**GAS**	**136,310**	**1,028,024**	**140,130.0**	**553,144**	**5.20**	**4.06**
16. B.B.#3 (GAS)	355	15,290	5.8	-	-	-	GAS	172,530	1,028,053	177,370.0	700,124	4.58	4.06
17. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**400**	**15,290**	**5.1**	**88.0**	**50.3**	**11,600**		**-**	**-**	**177,370.0**	**700,124**	**4.58**	**-**
19. B.B.#4 (GAS)	160	3,950	3.3	-	-	-	GAS	48,660	1,027,744	50,010.0	197,462	5.00	4.06
20. B.B.#4 (COAL)	432	75,210	23.4	-	-	-	COAL	42,230	22,502,250	950,270.0	2,970,432	3.95	70.34
21. BIG BEND #4 TOTAL	**432**	**79,160**	**24.6**	**61.5**	**39.9**	**12,636**		**-**	**-**	**1,000,280.0**	**3,167,894**	**4.00**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	17,950	-	18,450.0	72,841	-	4.06
23. B.B.C.T.#4 TOTAL	**61**	**1,110**	**2.4**	**98.2**	**82.7**	**11,541**	**GAS**	**12,460**	**1,028,090**	**12,810.0**	**50,562**	**4.56**	**4.06**
24. BIG BEND STATION TOTAL	**1,243**	**106,200**	**11.5**	**78.2**	**41.4**	**12,529**	**-**	**-**	**-**	**1,330,590.0**	**4,544,565**	**4.28**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	240	41,510	23.2	-	74.6	8,833	GAS	356,650	1,028,011	366,640.0	1,447,280	3.49	4.06
27. POLK #1 TOTAL	**220**	**41,510**	**25.4**	**94.2**	**74.6**	**8,833**	**-**	**-**	**-**	**366,640.0**	**1,447,280**	**3.49**	**-**
28. POLK #2 ST DUCT FIRING	120	10,730	12.0	-	79.1	8,171	GAS	85,280	1,028,025	87,670.0	346,065	3.23	4.06
29. POLK #2 ST W/O DUCT FIRING	360	730,373	-	-	-	-	GAS	4,918,775	1,028,016	5,056,581.4	19,960,310	2.73	4.06
30. POLK #2 ST TOTAL	**480**	**741,103**	**207.5**	**-**	**182.3**	**6,941**	**GAS**	**-**	**-**	**5,144,251.4**	**20,306,375**	**2.74**	**-**
31. POLK #2 CT (GAS)	180	1,310	1.0	-	80.9	10,962	GAS	13,970	1,027,917	14,360.0	56,690	4.33	4.06
32. POLK #2 CT (OIL)	187	1,329	1.0	-	7.6	10,996	LGT OIL	2,493	5,862,134	14,614.3	239,222	18.00	95.96
33. POLK #2 TOTAL [4]	**180**	**2,639**	**2.0**	**-**	**13.8**	**10,979**	**-**	**-**	**-**	**28,974.3**	**295,912**	**11.21**	**-**
34. POLK #3 CT (GAS)	180	1,130	0.8	-	78.5	11,035	GAS	12,120	1,028,878	12,470.0	49,183	4.35	4.06
35. POLK #3 CT (OIL)	187	1,329	1.0	-	80.2	10,996	LGT OIL	2,493	5,862,134	14,614.3	239,222	18.00	95.96
36. POLK #3 TOTAL [4]	**180**	**2,459**	**1.8**	**-**	**79.4**	**11,014**	**-**	**-**	**-**	**27,084.3**	**288,405**	**11.73**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,200**	**746,201**	**83.6**	**97.5**	**162.6**	**6,969**	**-**	**-**	**-**	**5,200,310.0**	**20,890,692**	**2.80**	**-**
40. POLK STATION TOTAL	**1,420**	**787,711**	**74.6**	**97.0**	**145.5**	**7,067**	**-**	**-**	**-**	**5,566,950.0**	**22,337,972**	**2.84**	**-**
41. BAYSIDE #1	792	165,710	28.1	56.4	52.0	7,390	GAS	1,191,290	1,028,003	1,224,650.0	4,834,236	2.92	4.06
42. BAYSIDE #2	1,047	354,260	45.5	97.4	46.7	7,589	GAS	2,615,350	1,027,996	2,688,570.0	10,613,048	3.00	4.06
43. BAYSIDE #3	61	1,320	2.9	98.6	90.2	11,379	GAS	14,610	1,028,063	15,020.0	59,287	4.49	4.06
44. BAYSIDE #4	61	1,130	2.5	98.6	88.2	11,336	GAS	12,480	1,026,442	12,810.0	50,644	4.48	4.06
45. BAYSIDE #5	61	1,600	3.5	98.6	93.7	11,238	GAS	17,490	1,028,016	17,980.0	70,974	4.44	4.06
46. BAYSIDE #6	61	1,380	3.0	98.6	90.5	11,312	GAS	15,180	1,028,327	15,610.0	61,600	4.46	4.06
47. BAYSIDE STATION TOTAL	**2,083**	**525,400**	**33.9**	**82.0**	**48.5**	**7,565**	**GAS**	**3,866,400**	**1,027,995**	**3,974,640.0**	**15,689,789**	**2.99**	**4.06**
48. SYSTEM TOTAL	**5,338**	**1,495,701**	**37.7**	**76.0**	**88.5**	**7,269**	**-**	**-**	**-**	**10,872,180.0**	**42,572,326**	**2.85**	**-**

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE
CC = COMBINED CYCLE
ST = STEAM TURBINE

[1] As burned fuel cost system total includes ignition
[2] Fuel burned (MM BTU) system total excludes ignition
[3] AC rating
[4] In Simple Cycle Mode

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Exhibit No. MAS-2
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TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD: JANUARY 2020 THROUGH JUNE 2020

SCHEDULE E5

	ACTUAL					
	Jan-20	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT ($)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT ($)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT ($)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	0	0	0	0	0	0
16. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
17. AMOUNT ($)	0	0	0	0	0	0
18. BURNED:						
19. UNITS (BBL)	0	0	0	0	440	759
20. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	127.57	147.10
21. AMOUNT ($)	0	0	0	0	56,132	111,650
22. ENDING INVENTORY:						
23. UNITS (BBL)	42,562	42,562	42,562	42,562	42,122	41,363
24. UNIT COST ($/BBL)	127.48	127.48	127.48	127.48	127.48	146.37
25. AMOUNT ($)	5,425,905	5,425,905	5,425,905	5,425,905	5,369,773	6,054,446
26. DAYS SUPPLY: NORMAL	577	577	575	575	569	629
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
COAL						
28. PURCHASES:						
29. UNITS (TONS)	2,587	0	0	31,857	93,606	29,583
30. UNIT COST ($/TON)	2.57	0.00	0.00	54.84	64.82	43.35
31. AMOUNT ($)	6,638	0	0	1,746,915	6,067,639	1,282,474
32. BURNED:						
33. UNITS (TONS)	82,330	0	(2,255)	0	0	41,559
34. UNIT COST ($/TON)	72.60	0.00	(558.15)	0.00	0.00	63.66
35. AMOUNT ($)	5,976,802	1,044,084	1,258,618	355,640	354,196	2,645,478
36. ENDING INVENTORY:						
37. UNITS (TONS)	222,715	204,744	202,284	229,426	323,032	311,056
38. UNIT COST ($/TON)	70.88	70.66	70.67	69.92	68.44	67.04
39. AMOUNT ($)	15,787,080	14,468,163	14,294,650	16,041,565	22,109,205	20,853,607
40. DAYS SUPPLY:	306	1,276	1,495	516	299	154
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	10,059,170	10,089,027	11,700,794	9,480,797	9,390,550	11,735,665
43. UNIT COST ($/MCF)	3.03	2.68	2.57	2.64	2.90	2.53
44. AMOUNT ($)	30,489,600	27,050,486	30,063,433	25,011,657	27,269,278	29,710,904
45. BURNED:						
46. UNITS (MCF)	10,057,418	10,067,881	11,701,767	9,429,039	9,453,126	11,750,533
47. UNIT COST ($/MCF)	3.03	2.68	2.57	2.67	2.89	2.53
48. AMOUNT ($)	30,456,415	27,009,533	30,120,929	25,136,658	27,297,597	29,777,968
49. ENDING INVENTORY:						
50. UNITS (MCF)	375,375	396,521	395,548	447,306	384,730	369,862
51. UNIT COST ($/MCF)	2.65	2.61	2.47	1.91	2.15	2.05
52. AMOUNT ($)	995,349	1,036,302	978,806	853,805	825,486	758,422
53. DAYS SUPPLY:	1	1	1	1	1	1
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-IGNITION, OTHER USAGE, AND ANALYSIS (2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENT (3) GAS-IGNITION AND ADDITIVES

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2020 THROUGH DECEMBER 2020

SCHEDULE E5

	Estimated						
	Jul-20	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**TOTAL**
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	0	0	0	0	0	0	0
3. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT ($)	0	0	0	0	0	0	0
5. BURNED:							
6. UNITS (BBL)	0	0	0	0	0	0	0
7. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT ($)	0	0	0	0	0	0	0
9. ENDING INVENTORY:							
10. UNITS (BBL)	0	0	0	0	0	0	0
11. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT ($)	0	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	4,985	6,885	6,724	4,744	3,940	4,985	32,263
16. UNIT COST ($/BBL)	41.75	43.86	45.59	47.31	48.56	49.62	45.86
17. AMOUNT ($)	208,114	301,970	306,533	224,449	191,323	247,344	1,479,733
18. BURNED:							
19. UNITS (BBL)	4,986	4,986	4,824	4,744	3,940	4,986	29,665
20. UNIT COST ($/BBL)	135.10	122.07	111.81	105.67	101.09	95.96	113.52
21. AMOUNT ($)	673,588	608,665	539,378	501,308	398,286	478,444	3,367,451
22. ENDING INVENTORY:							
23. UNITS (BBL)	41,363	43,263	45,163	45,163	45,163	45,163	45,163
24. UNIT COST ($/BBL)	135.12	122.10	111.80	105.67	101.09	95.97	95.97
25. AMOUNT ($)	5,588,972	5,282,277	5,049,432	4,772,574	4,565,611	4,334,511	4,334,511
26. DAYS SUPPLY: NORMAL	292	305	319	319	331	334	-
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	
COAL							
28. PURCHASES:							
29. UNITS (TONS)	57,017	15,000	15,000	15,000	30,000	30,000	319,650
30. UNIT COST ($/TON)	59.27	59.27	59.27	59.27	59.27	59.27	58.52
31. AMOUNT ($)	3,379,626	889,110	889,110	889,110	1,778,220	1,778,220	18,707,062
32. BURNED:							
33. UNITS (TONS)	59,450	60,940	60,180	28,920	22,850	42,230	396,204
34. UNIT COST ($/TON)	70.97	70.77	70.56	70.35	70.83	70.34	78.33
35. AMOUNT ($)	4,219,114	4,312,681	4,246,528	2,034,424	1,618,459	2,970,432	31,036,456
36. ENDING INVENTORY:							
37. UNITS (TONS)	308,623	262,683	217,503	203,583	210,733	198,503	198,503
38. UNIT COST ($/TON)	66.31	66.63	67.13	67.17	66.47	66.17	66.17
39. AMOUNT ($)	20,464,196	17,501,982	14,600,168	13,673,798	14,006,549	13,134,047	13,134,047
40. DAYS SUPPLY:	157	161	177	199	154	113	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	11,035,978	11,636,535	10,634,604	10,278,364	8,993,988	9,641,105	124,676,577
43. UNIT COST ($/MCF)	3.26	3.35	3.42	3.49	3.80	4.07	3.13
44. AMOUNT ($)	35,932,027	38,993,496	36,399,752	35,840,810	34,164,416	39,217,050	390,142,909
45. BURNED:							
46. UNITS (MCF)	11,016,735	11,636,535	10,634,604	10,278,364	9,091,264	9,641,105	124,758,371
47. UNIT COST ($/MCF)	3.25	3.35	3.42	3.48	3.78	4.06	3.13
48. AMOUNT ($)	35,816,049	38,952,696	36,378,152	35,805,610	34,337,816	39,123,450	390,212,873
49. ENDING INVENTORY:							
50. UNITS (MCF)	389,105	389,105	389,105	389,105	291,829	291,829	291,829
51. UNIT COST ($/MCF)	2.25	2.35	2.41	2.50	2.74	3.06	3.06
52. AMOUNT ($)	874,400	915,200	936,800	972,000	798,600	892,200	892,200
53. DAYS SUPPLY:	1	1	1	1	1	1	-
NUCLEAR							
54. BURNED:							
55. UNITS (MMBTU)	0	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0	0
OTHER							
58. PURCHASES:							
59. UNITS (MMBTU)	0	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0	0
62. BURNED:							
63. UNITS (MMBTU)	0	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0	0
66. ENDING INVENTORY:							
67. UNITS (MMBTU)	0	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0	

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-IGNITION AND ANALYSIS (2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENT (3) GAS-IGNITION

TAMPA ELECTRIC COMPANY
POWER SOLD
ACTUAL FOR THE PERIOD: JANUARY 2020 THROUGH JUNE 2020

SCHEDULE E6

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
MONTH	SOLD TO		TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST	GAINS ON MARKET BASED SALES
ACTUAL											
Jan-20	SEMINOLE	JURISD.	SCH. - D	3,795.0	0.0	3,795.0	2.121	2.333	80,478.22	88,526.04	4,292.71
	VARIOUS	JURISD.	SCH. - MA	150.0	0.0	150.0	1.409	2.315	2,113.50	3,471.81	1,077.81
	TOTAL			**3,945.0**	**0.0**	**3,945.0**	**2.094**	**2.332**	**82,591.72**	**91,997.85**	**5,370.52**
ACTUAL											
Feb-20	SEMINOLE	JURISD.	SCH. - D	3,830.0	0.0	3,830.0	1.559	1.715	59,722.65	65,694.92	4,843.65
	VARIOUS	JURISD.	SCH. - MA	900.0	0.0	900.0	2.019	3.317	18,171.00	29,854.45	10,468.45
	TOTAL			**4,730.0**	**0.0**	**4,730.0**	**1.647**	**2.020**	**77,893.65**	**95,549.37**	**15,312.10**
ACTUAL											
Mar-20	SEMINOLE	JURISD.	SCH. - D	3,341.0	0.0	3,341.0	1.441	1.585	48,146.46	52,961.11	3,804.28
	VARIOUS	JURISD.	SCH. - MA	9,946.0	0.0	9,946.0	1.581	2.797	157,201.09	278,170.73	100,897.96
	TOTAL			**13,287.0**	**0.0**	**13,287.0**	**1.545**	**2.492**	**205,347.55**	**331,131.84**	**104,702.24**
ACTUAL											
Apr-20	SEMINOLE	JURISD.	SCH. - D	2,824.0	0.0	2,824.0	1.099	1.209	31,045.12	34,149.63	2,332.60
	VARIOUS	JURISD.	SCH. - MA	925.0	0.0	925.0	1.285	0.485	11,886.25	4,486.76	(9,151.24)
	TOTAL			**3,749.0**	**0.0**	**3,749.0**	**1.145**	**1.031**	**42,931.37**	**38,636.39**	**(6,818.64)**
ACTUAL											
May-20	SEMINOLE	JURISD.	SCH. - D	3,717.0	0.0	3,717.0	1.239	1.363	46,046.98	50,651.68	3,630.47
	VARIOUS	JURISD.	SCH. - MA	225.0	0.0	225.0	1.271	2.678	2,859.15	6,025.15	2,718.85
	TOTAL			**3,942.0**	**0.0**	**3,942.0**	**1.241**	**1.438**	**48,906.13**	**56,676.83**	**6,349.32**
ACTUAL											
Jun-20	SEMINOLE	JURISD.	SCH. - D	2,806.0	0.0	2,806.0	1.112	1.223	31,194.10	34,313.51	2,340.92
	VARIOUS	JURISD.	SCH. - MA	1,254.0	0.0	1,254.0	1.334	2.688	16,733.83	33,705.66	14,395.56
	TOTAL			**4,060.0**	**0.0**	**4,060.0**	**1.180**	**1.675**	**47,927.93**	**68,019.17**	**16,736.48**

TAMPA ELECTRIC COMPANY

POWER SOLD

ESTIMATED FOR THE PERIOD: JULY 2020 THROUGH DECEMBER 2020

SCHEDULE E6

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
MONTH	SOLD TO		TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST	GAINS ON MARKET BASED SALES
ESTIMATED											
Jul-20	SEMINOLE	JURISD.	SCH. - D	2,980.0	0.0	2,980.0	2.067	2.656	61,610.00	79,163.00	4,544.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,980.0**	**0.0**	**2,980.0**	**2.067**	**2.656**	**61,610.00**	**79,163.00**	**4,544.00**
ESTIMATED											
Aug-20	SEMINOLE	JURISD.	SCH. - D	2,950.0	0.0	2,950.0	2.115	2.667	62,390.00	78,681.00	4,813.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,950.0**	**0.0**	**2,950.0**	**2.115**	**2.667**	**62,390.00**	**78,681.00**	**4,813.00**
ESTIMATED											
Sep-20	SEMINOLE	JURISD.	SCH. - D	2,950.0	0.0	2,950.0	2.216	2.674	65,380.00	78,869.00	5,001.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,950.0**	**0.0**	**2,950.0**	**2.216**	**2.674**	**65,380.00**	**78,869.00**	**5,001.00**
ESTIMATED											
Oct-20	SEMINOLE	JURISD.	SCH. - D	2,950.0	0.0	2,950.0	2.321	2.681	68,460.00	79,076.00	5,208.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,950.0**	**0.0**	**2,950.0**	**2.321**	**2.681**	**68,460.00**	**79,076.00**	**5,208.00**
ESTIMATED											
Nov-20	SEMINOLE	JURISD.	SCH. - D	2,870.0	0.0	2,870.0	2.357	2.684	67,650.00	77,021.00	5,156.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,870.0**	**0.0**	**2,870.0**	**2.357**	**2.684**	**67,650.00**	**77,021.00**	**5,156.00**
ESTIMATED											
Dec-20	SEMINOLE	JURISD.	SCH. - D	2,950.0	0.0	2,950.0	2.428	2.688	71,630.00	79,297.00	5,429.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,950.0**	**0.0**	**2,950.0**	**2.428**	**2.688**	**71,630.00**	**79,297.00**	**5,429.00**
TOTAL											
Jan-20	SEMINOLE	JURISD.	SCH. - D	37,963.0	0.0	37,963.0	1.827	2.103	693,753.53	798,403.89	51,395.63
THRU	VARIOUS	JURISD.	SCH. - MA	13,400.0	0.0	13,400.0	1.559	2.655	208,964.82	355,714.56	120,407.39
Dec-20	**TOTAL**			**51,363.0**	**0.0**	**51,363.0**	**1.758**	**2.247**	**902,718.35**	**1,154,118.45**	**171,803.02**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

SCHEDULE E7
REVISED 8/12/20

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL Jan-20									
	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	96.0	0.0	0.0	96.0	2.883	2.883	2,767.40
	TOTAL		**96.0**	**0.0**	**0.0**	**96.0**	**2.883**	**2.883**	**2,767.40**
ACTUAL Feb-20									
	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	(276.0)	0.0	0.0	(276.0)	1.383	1.383	(3,816.90)
	TOTAL		**(276.0)**	**0.0**	**0.0**	**(276.0)**	**1.383**	**1.383**	**(3,816.90)**
ACTUAL Mar-20									
	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
ACTUAL Apr-20									
	VARIOUS	SCH. - J	3,969.0	0.0	0.0	3,969.0	2.630	2.630	104,402.93
	VARIOUS	OATT	583.0	0.0	0.0	583.0	4.315	4.315	25,158.40
	TOTAL		**4,552.0**	**0.0**	**0.0**	**4,552.0**	**2.846**	**2.846**	**129,561.33**
ACTUAL May-20									
	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	1,888.0	0.0	0.0	1,888.0	4.160	4.160	78,533.56
	TOTAL		**1,888.0**	**0.0**	**0.0**	**1,888.0**	**4.160**	**4.160**	**78,533.56**
ACTUAL Jun-20									
	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	1,527.0	0.0	0.0	1,527.0	4.697	4.697	71,724.60
	TOTAL		**1,527.0**	**0.0**	**0.0**	**1,527.0**	**4.697**	**4.697**	**71,724.60**
ESTIMATED Jul-20									
	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
ESTIMATED Aug-20									
	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
ESTIMATED Sep-20									
	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
ESTIMATED Oct-20									
	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
ESTIMATED Nov-20									
	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
ESTIMATED Dec-20									
	VARIOUS	SCH. - J	1,533.0	0.0	0.0	1,533.0	3.994	3.994	61,224.33
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**1,533.0**	**0.0**	**0.0**	**1,533.0**	**3.994**	**3.994**	**61,224.33**
TOTAL									
Jan-20	VARIOUS	SCH. - J	5,502.0	0.0	0.0	5,502.0	3.010	3.010	165,627.26
THRU	VARIOUS	OATT	3,818.0	0.0	0.0	3,818.0	4.567	4.567	174,367.06
Dec-20	**TOTAL**		**9,320.0**	**0.0**	**0.0**	**9,320.0**	**3.648**	**3.648**	**339,994.32**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			CENTS/KWH		
		TYPE	TOTAL	FOR	MWH	MWH	(A)	(B)	TOTAL $
	PURCHASED	&	MWH	OTHER	FOR	FOR	FUEL	TOTAL	FOR FUEL
MONTH	FROM	SCHEDULE	PURCHASED	UTILITIES	INTERRUPTIBLE	FIRM	COST	COST	ADJUSTMENT
ACTUAL	**VARIOUS**	**CO-GEN.**							
Jan-20		NET METERING	0.2	0.0	0.0	0.2	2.532	2.532	3.95
		AS AVAIL.	4,103.0	0.0	0.0	4,103.0	2.162	2.162	88,709.94
	TOTAL		**4,103.2**	**0.0**	**0.0**	**4,103.2**	**2.162**	**2.162**	**88,713.89**
ACTUAL	**VARIOUS**	**CO-GEN.**							
Feb-20		NET METERING	2,161.1	0.0	0.0	2,161.1	2.207	2.207	47,698.91
		AS AVAIL.	14,263.0	0.0	0.0	14,263.0	1.708	1.708	243,642.84
	TOTAL		**16,424.1**	**0.0**	**0.0**	**16,424.1**	**1.774**	**1.774**	**291,341.75**
ACTUAL	**VARIOUS**	**CO-GEN.**							
Mar-20		NET METERING	9.6	0.0	0.0	9.6	2.208	2.208	211.43
		AS AVAIL.	10,779.0	0.0	0.0	10,779.0	1.586	1.586	170,966.67
	TOTAL		**10,788.6**	**0.0**	**0.0**	**10,788.6**	**1.587**	**1.587**	**171,178.10**
ACTUAL	**VARIOUS**	**CO-GEN.**							
Apr-20		NET METERING	6.7	0.0	0.0	6.7	2.208	2.208	147.89
		AS AVAIL.	17,373.0	0.0	0.0	17,373.0	1.254	1.254	217,879.36
	TOTAL		**17,379.7**	**0.0**	**0.0**	**17,379.7**	**1.254**	**1.254**	**218,027.25**
ACTUAL	**VARIOUS**	**CO-GEN.**							
May-20		NET METERING	3.7	0.0	0.0	3.7	2.208	2.208	81.49
		AS AVAIL.	8,772.0	0.0	0.0	8,772.0	1.371	1.371	120,254.21
	TOTAL		**8,775.7**	**0.0**	**0.0**	**8,775.7**	**1.371**	**1.371**	**120,335.70**
ACTUAL	**VARIOUS**	**CO-GEN.**							
Jun-20		NET METERING	16.8	0.0	0.0	16.8	2.208	2.208	371.18
		AS AVAIL.	8,124.0	0.0	0.0	8,124.0	1.317	1.317	107,017.28
	TOTAL		**8,140.8**	**0.0**	**0.0**	**8,140.8**	**1.319**	**1.319**	**107,388.46**
ESTIMATED	**VARIOUS**	**CO-GEN.**							
Jul-20		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	7,300.0	0.0	0.0	7,300.0	2.594	2.594	189,360.00
	TOTAL		**7,300.0**	**0.0**	**0.0**	**7,300.0**	**2.594**	**2.594**	**189,360.00**
ESTIMATED	**VARIOUS**	**CO-GEN.**							
Aug-20		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	7,170.0	0.0	0.0	7,170.0	2.955	2.955	211,880.00
	TOTAL		**7,170.0**	**0.0**	**0.0**	**7,170.0**	**2.955**	**2.955**	**211,880.00**
ESTIMATED	**VARIOUS**	**CO-GEN.**							
Sep-20		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	7,460.0	0.0	0.0	7,460.0	2.612	2.612	194,840.00
	TOTAL		**7,460.0**	**0.0**	**0.0**	**7,460.0**	**2.612**	**2.612**	**194,840.00**
ESTIMATED	**VARIOUS**	**CO-GEN.**							
Oct-20		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	7,330.0	0.0	0.0	7,330.0	2.701	2.701	198,000.00
	TOTAL		**7,330.0**	**0.0**	**0.0**	**7,330.0**	**2.701**	**2.701**	**198,000.00**
ESTIMATED	**VARIOUS**	**CO-GEN.**							
Nov-20		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	7,250.0	0.0	0.0	7,250.0	2.700	2.700	195,750.00
	TOTAL		**7,250.0**	**0.0**	**0.0**	**7,250.0**	**2.700**	**2.700**	**195,750.00**
ESTIMATED	**VARIOUS**	**CO-GEN.**							
Dec-20		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	7,200.0	0.0	0.0	7,200.0	2.330	2.330	167,730.00
	TOTAL		**7,200.0**	**0.0**	**0.0**	**7,200.0**	**2.330**	**2.330**	**167,730.00**
TOTAL	**VARIOUS**	**CO-GEN.**							
Jan-20		NET METERING	2,198.0	0.0	0.0	2,198.0	2.207	2.207	48,514.85
THRU		AS AVAIL.	107,124.0	0.0	0.0	107,124.0	1.966	1.966	2,106,030.30
Dec-20	**TOTAL**		**109,322.0**	**0.0**	**0.0**	**109,322.0**	**1.971**	**1.971**	**2,154,545.15**

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

SCHEDULE E9
REVISED 8/12/20

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
								COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) DOLLARS	FUEL SAVINGS (9B)-(8)
ACTUAL	VARIOUS	SCH. - J	8,366.0	0.0	8,366.0	3.759	314,502.80	3.808	318,546.00	4,043.20
Jan-20	**TOTAL**		**8,366.0**	**0.0**	**8,366.0**	**3.759**	**314,502.80**	**3.808**	**318,546.00**	**4,043.20**
ACTUAL	VARIOUS	SCH. - J	9,063.0	0.0	9,063.0	2.873	260,336.62	2.993	271,282.37	10,945.75
Feb-20	**TOTAL**		**9,063.0**	**0.0**	**9,063.0**	**2.873**	**260,336.62**	**2.993**	**271,282.37**	**10,945.75**
ACTUAL	VARIOUS	SCH. - J	11,672.0	0.0	11,672.0	3.798	443,296.06	4.199	490,108.06	46,812.00
Mar-20	**TOTAL**		**11,672.0**	**0.0**	**11,672.0**	**3.798**	**443,296.06**	**4.199**	**490,108.06**	**46,812.00**
ACTUAL	VARIOUS	SCH. - J	144,703.0	0.0	144,703.0	2.705	3,913,921.67	2.986	4,321,196.57	407,274.90
Apr-20	**TOTAL**		**144,703.0**	**0.0**	**144,703.0**	**2.705**	**3,913,921.67**	**2.986**	**4,321,196.57**	**407,274.90**
ACTUAL	VARIOUS	SCH. - J	337,957.0	0.0	337,957.0	2.729	9,221,265.73	3.108	10,504,286.15	1,283,020.42
May-20	**TOTAL**		**337,957.0**	**0.0**	**337,957.0**	**2.729**	**9,221,265.73**	**3.108**	**10,504,286.15**	**1,283,020.42**
ACTUAL	VARIOUS	SCH. - J	316,903.0	0.0	316,903.0	2.738	8,677,950.30	3.017	9,561,240.75	883,290.45
Jun-20	**TOTAL**		**316,903.0**	**0.0**	**316,903.0**	**2.738**	**8,677,950.30**	**3.017**	**9,561,240.75**	**883,290.45**
ESTIMATED	VARIOUS	SCH. - J	217,080.0	0.0	217,080.0	2.912	6,321,920.00	3.569	7,747,540.00	1,425,620.00
Jul-20	**TOTAL**		**217,080.0**	**0.0**	**217,080.0**	**2.912**	**6,321,920.00**	**3.569**	**7,747,540.00**	**1,425,620.00**
ESTIMATED	VARIOUS	SCH. - J	219,930.0	0.0	219,930.0	2.935	6,455,240.00	3.287	7,229,990.00	774,750.00
Aug-20	**TOTAL**		**219,930.0**	**0.0**	**219,930.0**	**2.935**	**6,455,240.00**	**3.287**	**7,229,990.00**	**774,750.00**
ESTIMATED	VARIOUS	SCH. - J	212,630.0	0.0	212,630.0	2.940	6,252,140.00	3.781	8,039,920.00	1,787,780.00
Sep-20	**TOTAL**		**212,630.0**	**0.0**	**212,630.0**	**2.940**	**6,252,140.00**	**3.781**	**8,039,920.00**	**1,787,780.00**
ESTIMATED	VARIOUS	SCH. - J	225,790.0	0.0	225,790.0	2.979	6,726,330.00	3.778	8,531,350.00	1,805,020.00
Oct-20	**TOTAL**		**225,790.0**	**0.0**	**225,790.0**	**2.979**	**6,726,330.00**	**3.778**	**8,531,350.00**	**1,805,020.00**
ESTIMATED	VARIOUS	SCH. - J	155,330.0	0.0	155,330.0	2.865	4,450,850.00	3.589	5,574,030.00	1,123,180.00
Nov-20	**TOTAL**		**155,330.0**	**0.0**	**155,330.0**	**2.865**	**4,450,850.00**	**3.589**	**5,574,030.00**	**1,123,180.00**
ESTIMATED	VARIOUS	SCH. - J	17,617.0	0.0	17,617.0	3.895	686,195.67	10.354	1,824,042.12	1,137,846.45
Dec-20	**TOTAL**		**17,617.0**	**0.0**	**17,617.0**	**3.895**	**686,195.67**	**10.354**	**1,824,042.12**	**1,137,846.45**
TOTAL										
Jan-20										
THRU	VARIOUS	SCH. - J	1,877,041.0	0.0	1,877,041.0	2.862	53,723,948.85	3.432	64,413,532.02	10,689,583.17
Dec-20	**TOTAL**		**1,877,041.0**	**0.0**	**1,877,041.0**	**2.862**	**53,723,948.85**	**3.432**	**64,413,532.02**	**10,689,583.17**

Docket No. 20200001-EI
CCR 2020 Actual/Estimated True-Up
Exhibit No. MAS-2
Document No. 2

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 2

CAPACITY COST RECOVERY

ACTUAL / ESTIMATED

JANUARY 2020 THROUGH DECEMBER 2020

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
CALCULATION OF THE CURRENT (ACTUAL/ESTIMATED) PERIOD TRUE-UP
JANUARY 2020 THROUGH DECEMBER 2020

1. ACTUAL/ESTIMATED OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2020 THROUGH DECEMBER 2020	$5,870,171
2. PROJECTED OVER/(UNDER) RECOVERY TRUE-UP INCLUDED IN JUNE - DECEMBER 2020 RATES (Per 2020 Mid-Course Correction, Exhibit D, Page 1, Line 15)	2,938,707
3. DIFFERENCE IN 2019 ESTIMATED TRUE-UP AMOUNT PROJECTED IN ORIGINAL 2019 RATES AND AMOUNT COLLECTED IN 2020 ($2,067,989) less $181,601 returned each month January 2020 through May 2020	(1,271,212)
4. ACTUAL-ESTIMATED 2020 OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2021 (Line 1 - Line 2 + Line 3)	1,660,252
5. FINAL TRUE-UP (January 2019 - December 2019) (Per 2019 True-Up filed March 2, 2020, Document No. 1, Page 1)	111,228
6. TOTAL OVER/(UNDER) RECOVERY (Line 4 + Line 5) To be included in the 12-month projected period January 2021 through December 2021	$1,771,480

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
JANUARY 2020 THROUGH DECEMBER 2020

	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	Total
1 UNIT POWER CAPACITY CHARGES	497,430	343,840	10,262	693,766	662,599	916,608	259,000	259,000	259,000	0	0	1,473,600	5,375,105
2 CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3 (UNIT POWER CAPACITY REVENUES)	(89,627)	(69,063)	(86,007)	(82,178)	(81,226)	(69,792)	(79,649)	(79,649)	(79,649)	(79,649)	(79,649)	(79,649)	(955,787)
4 TOTAL CAPACITY DOLLARS	407,803	274,777	(75,745)	611,588	581,373	846,816	179,351	179,351	179,351	(79,649)	(79,649)	1,393,951	4,419,318
5 SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6 JURISDICTIONAL CAPACITY DOLLARS	407,803	274,777	(75,745)	611,588	581,373	846,816	179,351	179,351	179,351	(79,649)	(79,649)	1,393,951	4,419,318
7 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	120,339	117,655	116,622	131,999	132,306	(189,542)	(199,301)	(202,419)	(204,363)	(189,166)	(160,113)	(151,094)	(677,077)
8 PRIOR PERIOD TRUE-UP PROVISION	(181,601)	(181,601)	(181,601)	(181,601)	(181,601)	419,815	419,815	419,815	419,815	419,815	419,815	419,817	2,030,702
9 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	(61,262)	(63,946)	(64,979)	(49,602)	(49,295)	230,273	220,514	217,396	215,452	230,649	259,702	268,723	1,353,625
10 TRUE-UP PROVISION FOR MONTH OVER/(UNDER) RECOVERY (Line 9 - Line 6)	(469,065)	(338,723)	10,766	(661,190)	(630,668)	(616,543)	41,163	38,045	36,101	310,298	339,351	(1,125,228)	(3,065,693)
11 INTEREST PROVISION FOR MONTH	(3,096)	(12)	3,826	2,182	110	250	891	1,304	1,182	1,104	1,074	814	9,629
12 ADJ - SOBRA 1 TRUE-UP IN FEBRUARY AND WIMAUMA SOBRA REFUND IN JUNE	0	4,856,329	0	0	0	4,069,905	0	0	0	0	0	0	8,926,235
13 TRUE-UP AND INT. PROVISION BEGINNING OF MONTH - OVER/(UNDER) RECOVERY	(2,067,989)	(2,358,549)	2,340,646	2,536,839	2,059,432	1,610,475	4,644,273	4,266,512	3,886,046	3,503,514	3,395,101	3,315,711	(2,067,989)
14 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS MONTH	181,601	181,601	181,601	181,601	181,601	(419,815)	(419,815)	(419,815)	(419,815)	(419,815)	(419,815)	(419,817)	(2,030,702)
15 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 10 - 14)	**(2,358,549)**	**2,340,646**	**2,536,839**	**2,059,432**	**1,610,475**	**4,644,273**	**4,266,512**	**3,886,046**	**3,503,514**	**3,395,101**	**3,315,711**	**1,771,480**	**1,771,480**

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Docket No. 20200001-EI
Exhibit No. MAS-2
Document No. 2, Page 2 of 4
Revised: 08/12/2020

47

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
JANUARY 2020 THROUGH DECEMBER 2020

	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	Total
1 BEGINNING TRUE-UP AMOUNT	(2,067,989)	(2,358,549)	2,340,646	2,536,839	2,059,432	1,610,475	4,644,273	4,266,512	3,886,046	3,503,514	3,395,101	3,315,711	(2,067,989)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(2,355,453)	2,340,658	2,533,013	2,057,250	1,610,365	4,644,023	4,265,621	3,884,742	3,502,332	3,393,997	3,314,637	1,770,666	(7,164,384)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(4,423,442)	(17,891)	4,873,660	4,594,090	3,669,798	6,254,498	8,909,893	8,151,253	7,388,377	6,897,510	6,709,737	5,086,376	(9,232,373)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(2,211,721)	(8,945)	2,436,830	2,297,045	1,834,899	3,127,249	4,454,947	4,075,627	3,694,189	3,448,755	3,354,869	2,543,188	(4,616,187)
5 INTEREST RATE % - 1ST DAY OF MONTH	1.710	1.640	1.560	2.210	0.060	0.080	0.110	0.380	0.380	0.380	0.380	0.380	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	1.640	1.560	2.210	0.060	0.080	0.110	0.380	0.380	0.380	0.380	0.380	0.380	NA
7 TOTAL (LINE 5 + LINE 6)	3.350	3.200	3.770	2.270	0.140	0.190	0.490	0.760	0.760	0.760	0.760	0.760	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	1.675	1.600	1.885	1.135	0.070	0.095	0.245	0.380	0.380	0.380	0.380	0.380	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.140	0.133	0.157	0.095	0.006	0.008	0.020	0.032	0.032	0.032	0.032	0.032	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(3,096)	(12)	3,826	2,182	110	250	891	1,304	1,182	1,104	1,074	814	9,629

REDACTED

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TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

SCHEDULE E12
REVISED 8/12/20

CONTRACT	TERM START	TERM END	CONTRACT TYPE
SEMINOLE ELECTRIC **	6/1/1992	-----------	LT
FLORIDA MUNICIPAL POWER AGENCY	12/1/2019	2/29/2020	ST
FLORIDA MUNICIPAL POWER AGENCY	7/1/2020	9/30/2020	ST
FLORIDA MUNICIPAL POWER AGENCY	12/1/2020	2/28/2021	ST
ORLANDO UTILITIES COMMISSION	12/1/2020	2/28/2021	ST
FLORIDA POWER & LIGHT	12/1/2020	2/28/2021	ST

QF = QUALIFYING FACILITY
LT = LONG TERM
ST = SHORT-TERM
** THREE YEAR NOTICE REQUIRED FOR TERMINATION.

CONTRACT	ACT JANUARY MW	ACT FEBRUARY MW	ACT MARCH MW	ACT APRIL MW	ACT MAY MW	ACT JUNE MW	EST JULY MW	EST AUGUST MW	EST SEPTEMBER MW	EST OCTOBER MW	EST NOVEMBER MW	EST DECEMBER MW
SEMINOLE ELECTRIC	9.5	8.8	5.0	10.0	10.5	8.5	10.0	10.0	10.0	10.0	10.0	10.0
FLORIDA MUNICIPAL POWER AGENCY	88.0	100.0	-	-	-	-	74.0	74.0	74.0	-	-	150.0
ORLANDO UTILITIES COMMISSION	-	-	-	-	-	-	-	-	-	-	-	100.0
FLORIDA POWER & LIGHT	-	-	-	-	-	-	-	-	-	-	-	160.0

CAPACITY	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
FLORIDA POWER & LIGHT	[redacted]												
DUKE ENERGY FLORIDA													
FLORIDA MUNICIPAL POWER AGENCY													
ORLANDO UTILITIES COMMISSION													
JACKSONVILLE ELECTRIC AUTHORITY													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS - MA													
CITY OF TALLAHASSEE - MA													
DUKE ENERGY FLORIDA - MA													
FLORIDA POWER & LIGHT - MA													
ORLANDO UTILITIES COMMISSION - MA													
THE ENERGY AUTHORITY - MA													
MORGAN STANLEY - MA													
SOUTHERN CO - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	407,803	274,777	(75,745)	611,588	581,373	846,816	179,351	179,351	179,351	(79,649)	(79,649)	1,393,951	4,419,318
TOTAL CAPACITY	407,803	274,777	(75,745)	611,588	581,373	846,816	179,351	179,351	179,351	(79,649)	(79,649)	1,393,951	4,419,318

Docket No. 20200001-EI
Exhibit No. MAS-2
Document No. 2, Page 4 of 4
Revised: 08/12/2020

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 3

CAPITAL PROJECTS APPROVED FOR

FUEL CLAUSE RECOVERY

JANUARY 2020 - DECEMBER 2020

50

BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ESTIMATE JUNE	ESTIMATE JULY	ESTIMATE AUGUST	ESTIMATE SEPTEMBER	ESTIMATE OCTOBER	ESTIMATE NOVEMBER	ESTIMATE DECEMBER	TOTAL
1 BEGINNING BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348								$20,910,348
2 ADD INVESTMENT: Big Bend Unit 3 (Jan 2015)	-	-	-	-	-								-
2a ADD INVESTMENT: Big Bend Unit 4 (May 2015)	-	-	-	-	-								-
2b ADD INVESTMENT: Big Bend Unit 2 (June 2015)	-	-	-	-	-								-
2c 2015)	-	-	-	-	-								-
3 LESS RETIREMENTS	-	-	-	-	-								-
4 ENDING BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348								$20,910,348
5													
6													
7 AVERAGE BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348								
8 DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%								
9 DEPRECIATION EXPENSE	$348,506	$348,506	$348,506	$348,506	$238,475								$1,632,499
10 LESS RETIREMENTS	-	-	-	-	-								-
11 BEGINNING BALANCE DEPRECIATION	$19,277,850	$19,626,355	$19,974,861	$20,323,367	$20,671,873								$19,277,850
12 ENDING BALANCE DEPRECIATION	$19,626,355	$19,974,861	$20,323,367	$20,671,873	$20,910,348								$20,910,348
13													
14													
15 ENDING NET INVESTMENT	$1,283,993	$935,487	$586,981	$238,475	-								-
16													
17													
18 AVERAGE INVESTMENT	$1,458,246	$1,109,740	$761,234	$412,728	$119,238								
19 ALLOWED EQUITY RETURN	.37413%	.37413%	.37413%	.37413%	.37413%								
20 EQUITY COMPONENT AFTER-TAX	$5,456	$4,152	$2,848	$1,544	$446								$14,446
21 CONVERSION TO PRE-TAX	1.32830	1.32830	1.32830	1.32830	1.32830								
22 EQUITY COMPONENT PRE-TAX	$7,247	$5,515	$3,783	$2,051	$592								$19,188
23													
24 ALLOWED DEBT RETURN	.14474%	.14474%	.14474%	.14474%	.14474%								
25 DEBT COMPONENT	$2,111	$1,606	$1,102	$597	$173								$5,589
26 TAX REFORM TRUEUP													
27 TOTAL RETURN REQUIREMENTS	$9,358	$7,121	$4,885	$2,648	$765								$24,777
28 PRIOR MONTH TRUE-UP													
29 TOTAL DEPRECIATION & RETURN	$357,864	$355,627	$353,391	$351,154	$239,240								$1,657,276
30													
31 ESTIMATED FUEL SAVINGS	$226,880	$100,996	$338,796	$15,142	$481,133	$925,295	$204,795	$452,378	$405,340	$829,055	$628,863	$255,886	$4,864,559
32 TOTAL DEPRECIATION & RETURN	$357,864	$355,627	$353,391	$351,154	$239,240								$1,657,276
33 NET BENEFIT (COST) TO RATEPAYER	($130,984)	($254,631)	($14,594)	($336,012)	$241,893	$925,295	$204,795	$452,378	$405,340	$829,055	$628,863	$255,886	$3,207,284

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.

35 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - MAY USING AN ANNUAL RATE OF 7.7004% (EQUITY 5.9635% , DEBT 1.7369%). RATES ARE BASED ON THE MAY 2019 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).

36 THE RETURN REQUIREMENT FOR JANUARY - DECEMBER IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 24.522%

37 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
January 2020 to June 2020

	(1) Jurisdictional Rate Base Actual May 2019 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,897,597	31.57%	4.89%	1.5435%
Short Term Debt	211,895	3.52%	2.97%	0.1047%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	94,966	1.58%	2.38%	0.0376%
Common Equity	2,598,065	43.22%	10.25%	4.4297%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,125,550	18.72%	0.00%	0.0000%
Deferred ITC - Weighted Cost	83,633	1.39%	7.98%	0.1110%
Total	$ 6,011,707	100.00%		6.23%

ITC split between Debt and Equity:

Long Term Debt	$ 1,897,597	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,598,065	Equity - Common	54.00%
Total	$ 4,495,662	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.1110% * 46.00%	0.0511%
Equity = 0.1110% * 54.00%	0.0599%
Weighted Cost	0.1110%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4297%
Deferred ITC - Weighted Cost	0.0599%
	4.4896%
Times Tax Multiplier	1.32830
Total Equity Component	5.9635%

Total Debt Cost Rate:

Long Term Debt	1.5435%
Short Term Debt	0.1047%
Customer Deposits	0.0376%
Deferred ITC - Weighted Cost	0.0511%
Total Debt Component	1.7369%
	7.7004%

Notes:
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 4

LAKE HANCOCK STIPULATED ISSUE

FUEL SAVINGS

JANUARY 2020 - DECEMBER 2020

53

Lake Hancock Stipulated Issue Fuel Savings

In-service Date: 4/25/2019

		2019											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1.	Sun Select Generation (MWh)	-	-	-	377	4,276	1,925	2,232	2,467	3,300	2,535	2,198	1,544
2.	Sun Select Billed Generation (MWh)	-	-	-	-	-	-	1.3	41.0	94.3	125.6	124.8	120.6
3.	Second SoBRA Projects Total Generation (MWh)	12,166	24,089	44,162	46,113	44,182	38,654	39,118	34,250	48,155	39,076	32,077	25,507
4.	5 MW Portion of Second SoBRA Generation (MWh)	234	463	848	886	849	742	751	658	925	751	616	490
5.	Generation for Agreement (MWh) = 1 - 2 + 4	234	463	848	1,263	5,125	2,667	2,982	3,084	4,131	3,160	2,689	1,914
6.	Natural Gas Burned (mmBtu) Schedule A4	9,515,986	9,623,649	10,898,853	11,776,196	13,721,616	12,259,286	12,593,318	13,225,218	14,130,496	13,445,259	9,258,123	10,544,011
7.	Net Natural Gas Generation (MWh) Schedule A4	1,249,223	1,241,142	1,427,169	1,451,957	1,794,486	1,642,401	1,669,828	1,742,731	1,790,253	1,733,549	1,189,663	1,317,204
8.	Natural Gas Heat Rate (Btu/kWh) = 6 ÷ 7 x 1000 Schedule A4	7,618	7,754	7,637	8,111	7,647	7,464	7,542	7,589	7,893	7,756	7,782	8,005
9.	Actual Natural Gas Price ($/mmBtu) Schedule A5	4.70	3.86	3.79	3.60	3.50	3.62	3.37	3.18	3.34	3.36	3.69	3.43
10.	Fuel Savings ($) = 5 x 8 x 9 ÷ 1000	8,360	13,843	24,539	36,869	137,071	72,003	75,813	74,375	108,764	82,310	77,122	52,607
11.	Cummulative Fuel Savings ($)	8,360	22,203	46,743	83,612	220,683	292,685	368,498	442,874	551,638	633,948	711,071	763,678
12.	Total 2019 Shortfall to $1 Million Fuel Savings Agreement	(236,322)											

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2021 - DECEMBER 2021

AND

SCHEDULE E12

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI   EXHIBIT: 43
PARTY: TAMPA ELECTRIC COMPANY – DIRECT
DESCRIPTION: M. Ashley Sizemore MAS-3

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2021 THROUGH DECEMBER 2021
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MW)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MW)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)	(10) 12 CP & 1/13 AVG DEMAND FACTOR (%)
RS,RSVP	53.49%	9,684,803	2,067	1.08051	1.05263	10,194,472	2,233	49.67%	58.72%	58.02%
GS, CS	56.42%	902,049	182	1.08051	1.05261	949,504	197	4.63%	5.18%	5.14%
GSD Optional	3.42%	360,212	55	1.07583	1.04913	377,910	59	1.84%	1.55%	1.57%
GSD, SBF	71.57%	7,544,170	1,148	1.07583	1.04913	7,914,823	1,236	38.57%	32.50%	32.97%
IS,SBI	145.94%	927,861	73	1.02893	1.01716	943,787	75	4.60%	1.97%	2.17%
LS1	578.30%	134,246	3	1.08051	1.05263	141,311	3	0.69%	0.08%	0.13%
TOTAL		19,553,341	3,528			20,521,807	3,803	100.00%	100.00%	100.00%

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(1) AVG 12 CP load factor based on 2020 projected calendar data.
(2) Projected MWH sales for the period January 2021 thru December 2021.
(3) Based on 12 months average CP at meter.
(4) Based on 2020 projected demand losses.
(5) Based on 2020 projected energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Based on 12 months average percentage of sales at generation.
(9) Based on 12 months average percentage of demand at generation.
(10) Col (8) * 0.0769 + Col (9) * 0.9231

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2021 THROUGH DECEMBER 2021
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,473,600	1,473,600	0	0	0	0	0	0	0	0	0	0	2,947,200
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(UNIT POWER CAPACITY REVENUES)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,508)	(822,085)
4	TOTAL CAPACITY DOLLARS	$1,405,093	$1,405,093	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,508)	$2,125,115
5	SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6	JURISDICTIONAL CAPACITY DOLLARS	$1,405,093	$1,405,093	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,508)	$2,125,115
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2020 - DEC. 2020													(1,771,480)
8	TOTAL													$353,635
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$353,890

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EXHIBIT NO. MAS-3
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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2021 THROUGH DECEMBER 2021
PROJECTED

RATE CLASS	(1) PERCENTAGE OF SALES AT GENERATION (%)	(2) PERCENTAGE OF DEMAND AT GENERATION (%)	(3) ENERGY RELATED COSTS ($)	(4) DEMAND RELATED COSTS ($)	(5) TOTAL CAPACITY COSTS ($)	(6) PROJECTED SALES AT METER (MWH)	(7) EFFECTIVE AT SECONDARY LEVEL (MWH)	(8) BILLING KW LOAD FACTOR (%)	(9) PROJECTED BILLED KW AT METER (kw)	(10) CAPACITY RECOVERY FACTOR ($/kw)	(11) CAPACITY RECOVERY FACTOR ($/kwh)
RS	49.67%	58.72%	13,517	191,824	205,341	9,684,803	9,684,803				0.00002
GS, CS	4.63%	5.18%	1,260	16,922	18,182	902,049	902,049				0.00002
GSD, SBF											
Secondary						6,132,121	6,132,121			0.01	
Primary						1,405,148	1,391,097			0.01	
Transmission						6,901	6,763			0.01	
GSD, SBF - Standard	38.57%	32.50%	10,496	106,170	116,666	7,544,170	7,529,981	58.85%	17,528,483		
GSD - Optional	1.84%	1.55%	501	5,063	5,564						
Secondary						352,605	352,605				0.00002
Primary						7,607	7,531				0.00002
Transmission						0	0				0.00002
IS, SBI											
Primary						184,855	183,006			0.00	
Transmission						743,006	728,146			0.00	
Total IS, SBI	4.60%	1.97%	1,252	6,436	7,688	927,861	911,152	62.85%	1,986,004		
LS1	0.69%	0.08%	188	261	449	134,246	134,246				0.00000
TOTAL	100.00%	100.00%	27,214	326,676	353,890	19,553,341	19,522,367				0.00002

(1) Obtained from page 1.
(2) Obtained from page 1.
(3) Total capacity costs * 0.0769 * Col (1).
(4) Total capacity costs * 0.9231 * Col (2).
(5) Col (3) + Col (4).
(6) Projected kWh sales for the period January 2021 through December 2021.
(7) Projected kWh sales at secondary for the period January 2021 through December 2021.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2021 through December 2021.
(10) Total Col (5) / Total Col (9).
(11) {Col (5) / Total Col (7)} / 1000.

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REDACTED

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE
SEMINOLE ELECTRIC **	6/1/1992	-----------	LT
FLORIDA MUNICIPAL POWER AGENCY	12/1/2020	2/28/2021	ST
ORLANDO UTILITIES COMMISSION	12/1/2020	2/28/2021	ST
FLORIDA POWER & LIGHT	12/1/2020	2/28/2021	ST

QF = QUALIFYING FACILITY
LT = LONG TERM
ST = SHORT-TERM
**** THREE YEAR NOTICE REQUIRED FOR TERMINATION.**

CONTRACT	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
SEMINOLE ELECTRIC	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
FLORIDA MUNICIPAL POWER AGENCY	150.0	150.0	-	-	-	-	-	-	-	-	-	-
ORLANDO UTILITIES COMMISSION	100.0	100.0	-	-	-	-	-	-	-	-	-	-
FLORIDA POWER & LIGHT	160.0	160.0	-	-	-	-	-	-	-	-	-	-

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
FLORIDA MUNICIPAL POWER AGENCY	[redacted]												
ORLANDO UTILITIES COMMISSION													
FLORIDA POWER & LIGHT													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	1,405,093	1,405,093	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,508)	2,125,115
TOTAL CAPACITY	**$1,405,093**	**$1,405,093**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,508)**	**$2,125,115**

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 1, PAGE 4 OF 4

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2021 - DECEMBER 2021

SCHEDULES E1 THROUGH E10
SCHEDULE H1

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	575,218,013	20,177,369	2.85081
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Adjustment	0	0	0.00000
4b.	Adjustment	0	0	0.00000
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**575,218,013**	**20,177,369**	**2.85081**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	104,253	2,394	4.35476
7.	Energy Cost of Economy Purchases (E9)	10,935,277	297,946	3.67022
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	2,933,490	108,020	2.71569
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**13,973,020**	**408,360**	**3.42174**
11.	**TOTAL AVAILABLE MWH (LINE 5 + LINE 10)**		**20,585,729**	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	973,880	35,040	2.77934
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	0	0	0.00000
14.	Gains on Sales	73,807	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**1,047,687**	**35,040**	**2.98997**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		0	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**588,143,346**	**20,550,689**	**2.86192**
20.	Net Unbilled	NA [1][a]	NA [a]	NA
21.	Company Use	1,064,634 [1]	37,200	0.00545
22.	T & D Losses	27,714,830 [1]	968,400	0.14180
23.	System MWH Sales	588,143,346	19,545,089	3.00916
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	588,143,346	19,545,089	3.00916
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	588,143,346	19,545,089	3.00916
28.	Optimization Mechanism [2]	1,180,820	19,545,089	0.00604
29.	True-up [2]	25,479,055	19,545,089	0.13036
30.	Total Jurisdictional Fuel Cost (Excl. GPIF)	614,803,221	19,545,089	3.14556
31.	Revenue Tax Factor			1.00072
32.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	615,245,879	19,545,089	3.14782
33.	GPIF Adjusted for Taxes [2]	2,858,056	19,545,089	0.01462
34.	**Fuel Factor Adjusted for Taxes Including GPIF**	618,103,935	19,545,089	3.16244
35	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.162**

[a] Data not available at this time.
[1] Included For Informational Purposes Only
[2] Calculation Based on Jurisdictional MWH Sales

TAMPA ELECTRIC COMPANY
CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2020 - December 2020 (6 months actual, 6 months estimated)	($43,367,307)
2.	PROJECTED OVER/UNDER-RECOVERY TRUE-UP INCLUDED IN JUNE - DECEMBER 2020 RATES (Per Mid-Course correction Schedule E1-C, line 1B)	$0
3.	DIFFERENCE IN 2019 ESTIMATED TRUE-UP AMOUNT PROJECTED IN ORIGINAL 2020 RATES AND AMOUNT COLLECTED IN 2020 ($30,742,026 under-recovery less ($2,561,836) refunded each month January through May 2020)	($17,932,846)
4.	ACTUAL-ESTIMATED 2020 OVER/(UNDER) RECOVERY (Line 1 - Line 2 + Line 3)	($61,300,153)
5.	FINAL TRUE-UP (January 2019 - December 2019) (Per True-Up filed March 2, 2020)	35,821,098
6.	TOTAL OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2021 (Line 4 + Line 5) To be included in the 12-month projected period January 2021 through December 2021 (2021 Schedule E1, line 29)	($25,479,055)
7.	JURISDICTIONAL MWH SALES (Projected January 2021 through December 2021)	19,545,089
8.	TRUE-UP FACTOR - cents/kWh (Using Effective MWh Sales of 19,514,116)	**0.1306**

TAMPA ELECTRIC COMPANY **SCHEDULE E1-C**
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2021 through December 2021)	$2,858,056	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2021 through December 2021)	($25,479,055)	
	C. OPTIMIZATION MECHANISM GAIN / (LOSS) (January 2021 through December 2021)	$1,180,820	
2.	TOTAL SALES (January 2021 through December 2021)	19,545,089	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR (Using Effective MWh Sales of 19,514,116)	**0.0146**	Cents/kWh
	B. TRUE-UP FACTOR (Using Effective MWh Sales of 19,514,116)	**0.1306**	Cents/kWh
	C. OPTIMIZATION MECHANISM FACTOR (Using Effective MWh Sales of 19,514,116)	**0.0061**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	30.06	$23.79
OFF PEAK	69.94	$22.08
	100.00	1.0774

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$588,143,346		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	19,545,089		
2a	Effective MWH Sales (Jurisd)		19,514,116		
3	Cost Per KWH Sold	(line 1 / line 2)	3.0092		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		NA		
6	True-Up	(Sch E1 line 29)	$25,479,055		
7	Optimization Mechanism	(Sch E1 line 28)	$1,180,820		
8	TOTAL	(line 1 x line 4) + line 6 + line 7	$614,803,221		
9	Revenue Tax Factor		1.00072		
10	Recovery Factor	(line 8 x line 9) / line 2a / 10	3.1528		
11	GPIF Factor	(Sch E1-C line 3A)	0.0146		
12	Recovery Factor Including GPIF	(line 10 + line 11)	3.1674	3.3350	3.0953
13	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.167	3.335	3.095

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14	Hours: ON PEAK	25.51%
15	OFF PEAK	74.49%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Line Loss	Secondary
Distribution Secondary	17,197,572		17,197,572
Distribution Primary	1,597,611	0.99	1,581,635
Transmission	749,907	0.98	734,909
Total	19,545,089		19,514,116

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.167	3.335	3.095
Distribution Primary	3.135	3.302	3.064
Transmission	3.104	3.268	3.033
RS 1st Tier	2.856		
RS 2nd Tier	3.856		
Lighting	3.136		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

METERING VOLTAGE LEVEL	LEVELIZED FUEL RECOVERY FACTOR cents/kWh	FIRST TIER (Up to 1000 kWh) cents/kWh	SECOND TIER (OVER 1000 kWh) cents/kWh
STANDARD			
Distribution Secondary (RS only)		2.856	3.856
Distribution Secondary	3.167		
Distribution Primary	3.135		
Transmission	3.104		
Lighting Service (1)	3.136		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.335		
Distribution Secondary - Off-Peak	3.095		
Distribution Primary - On-Peak	3.302		
Distribution Primary - Off-Peak	3.064		
Transmission - On-Peak	3.268		
Transmission - Off-Peak	3.033		

(1) Lighting service is based on distribution secondary, 17% on-peak and 83% off-peak

SCHEDULE E2

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
						ESTIMATED							TOTAL
	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	PERIOD
1. Fuel Cost of System Net Generation	42,503,342	39,868,097	42,920,541	41,640,728	49,408,392	54,031,615	56,408,656	57,134,359	54,626,784	51,096,137	40,083,748	45,495,614	575,218,013
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold (1)	82,717	78,758	89,538	86,590	95,573	100,683	88,656	89,247	94,357	80,587	80,125	80,856	1,047,687
4. Fuel Cost of Purchased Power	28,164	76,089	0	0	0	0	0	0	0	0	0	0	104,253
5. Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Payments to Qualifying Facilities	217,090	252,980	197,130	229,010	232,390	247,890	251,500	249,360	248,330	290,630	275,890	241,290	2,933,490
7. Energy Cost of Economy Purchases	2,886,796	1,438,741	461,410	330,920	599,060	743,490	374,170	464,070	202,680	3,322,110	106,180	5,650	10,935,277
8. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
9. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
10. TOTAL FUEL & NET POWER TRANSACTIONS	**45,552,675**	**41,557,149**	**43,489,543**	**42,114,068**	**50,144,269**	**54,922,312**	**56,945,670**	**57,758,542**	**54,983,437**	**54,628,290**	**40,385,693**	**45,661,698**	**588,143,346**
11. Jurisdictional MWH Sold	1,471,672	1,355,362	1,336,932	1,416,998	1,572,691	1,830,995	1,913,414	1,902,089	1,992,078	1,802,624	1,511,740	1,438,493	19,545,089
12. Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
13. Jurisdictional Total Fuel & Net Power Transactions (Line 10 * Line 12)	45,552,675	41,557,149	43,489,543	42,114,068	50,144,269	54,922,312	56,945,670	57,758,542	54,983,437	54,628,290	40,385,693	45,661,698	588,143,346
14. Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
15. JURISD. TOTAL FUEL & NET PWR. TRANS. Adjusted for Line Losses (Line 13 * Line 14)	**45,552,675**	**41,557,149**	**43,489,543**	**42,114,068**	**50,144,269**	**54,922,312**	**56,945,670**	**57,758,542**	**54,983,437**	**54,628,290**	**40,385,693**	**45,661,698**	**588,143,346**
16. Cost Per kWh Sold (Cents/kWh)	3.0953	3.0661	3.2529	2.9721	3.1884	2.9996	2.9761	3.0366	2.7601	3.0305	2.6715	3.1743	3.0092
17. Optimization Mechanism (Cents/kWh) (2)	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061
18. True-up (Cents/kWh) (2)	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306
19. Total (Cents/kWh) (Line 16+17+18)	3.2320	3.2028	3.3896	3.1088	3.3251	3.1363	3.1128	3.1733	2.8968	3.1672	2.8082	3.3110	3.1459
20. Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
21. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.2343	3.2051	3.3920	3.1110	3.3275	3.1386	3.1150	3.1756	2.8989	3.1695	2.8102	3.3134	3.1482
22. GPIF Adjusted for Taxes (Cents/kWh) (2)	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146
23. TOTAL RECOVERY FACTOR (LINE 21+22)	**3.2489**	**3.2197**	**3.4066**	**3.1256**	**3.3421**	**3.1532**	**3.1296**	**3.1902**	**2.9135**	**3.1841**	**2.8248**	**3.3280**	**3.1628**
24. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**3.249**	**3.220**	**3.407**	**3.126**	**3.342**	**3.153**	**3.130**	**3.190**	**2.914**	**3.184**	**2.825**	**3.328**	**3.163**

(1) Includes Gains
(2) Based on Effective MWh Sales shown on Schedule E1-C

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 7 OF 42

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH JUNE 2021

SCHEDULE E3

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	487,933	0	470,965	340,852	445,648	419,916
3. COAL	4,387,675	4,136,102	2,316,287	3,167,903	5,971,387	5,734,099
4. NATURAL GAS	37,627,734	35,731,995	40,133,289	38,131,973	42,991,357	47,877,600
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**42,503,342**	**39,868,097**	**42,920,541**	**41,640,728**	**49,408,392**	**54,031,615**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	2,658	0	2,658	1,972	2,658	2,572
10. COAL	106,900	97,280	57,210	73,730	147,030	137,100
11. NATURAL GAS	1,164,793	1,074,920	1,245,613	1,320,839	1,480,223	1,653,809
12. SOLAR	97,450	107,360	134,250	163,800	179,270	154,170
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,371,801**	**1,279,560**	**1,439,731**	**1,560,341**	**1,809,181**	**1,947,651**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	4,986	0	4,986	3,698	4,986	4,824
17. COAL (TON)	61,050	55,390	30,780	40,910	77,080	72,580
18. NATURAL GAS (MCF)	8,403,735	8,272,150	9,654,975	9,848,783	11,190,315	12,398,004
19. SOLAR	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	29,229	0	29,229	21,686	29,229	28,286
23. COAL	1,373,610	1,246,200	692,540	920,490	1,734,280	1,632,960
24. NATURAL GAS	8,616,341	8,493,510	9,884,201	10,085,514	11,462,561	12,706,964
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**10,019,180**	**9,739,710**	**10,605,970**	**11,027,690**	**13,226,070**	**14,368,210**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.19	0.00	0.18	0.13	0.15	0.13
30. COAL	7.80	7.60	3.98	4.72	8.12	7.04
31. NATURAL GAS	84.91	84.01	86.52	84.65	81.82	84.91
32. SOLAR	7.10	8.39	9.32	10.50	9.91	7.92
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	97.86	0.00	94.46	92.17	89.38	87.05
37. COAL ($/TON)	71.87	74.67	75.25	77.44	77.47	79.00
38. NATURAL GAS ($/MCF)	4.48	4.32	4.16	3.87	3.84	3.86
39. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	16.69	0.00	16.11	15.72	15.25	14.85
43. COAL	3.19	3.32	3.34	3.44	3.44	3.51
44. NATURAL GAS	4.37	4.21	4.06	3.78	3.75	3.77
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**4.24**	**4.09**	**4.05**	**3.78**	**3.74**	**3.76**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	10,996	0	10,996	10,997	10,996	10,998
50. COAL	12,849	12,810	12,105	12,485	11,795	11,911
51. NATURAL GAS	7,397	7,902	7,935	7,636	7,744	7,683
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**7,304**	**7,612**	**7,367**	**7,067**	**7,311**	**7,377**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	18.36	0.00	17.72	17.28	16.77	16.33
57. COAL	4.10	4.25	4.05	4.30	4.06	4.18
58. NATURAL GAS	3.23	3.32	3.22	2.89	2.90	2.89
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.10**	**3.12**	**2.98**	**2.67**	**2.73**	**2.77**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

SCHEDULE E3

		Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	423,442	414,405	393,706	381,030	312,743	390,597	4,481,237
3.	COAL	5,559,374	5,769,559	5,461,415	3,123,824	0	1,825,597	47,453,222
4.	NATURAL GAS	50,425,840	50,950,395	48,771,663	47,591,283	39,771,005	43,279,420	523,283,554
5.	SOLAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**56,408,656**	**57,134,359**	**54,626,784**	**51,096,137**	**40,083,748**	**45,495,614**	**575,218,013**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	2,658	2,658	2,572	2,529	2,100	2,658	27,693
10.	COAL	127,660	134,920	126,580	71,810	0	39,460	1,119,680
11.	NATURAL GAS	1,753,893	1,780,653	1,690,579	1,538,631	1,343,880	1,396,893	17,444,726
12.	SOLAR	150,450	145,640	125,760	125,370	99,020	102,730	1,585,270
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**2,034,661**	**2,063,871**	**1,945,491**	**1,738,340**	**1,445,000**	**1,541,741**	**20,177,369**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	4,986	4,986	4,824	4,744	3,940	4,986	51,946
17.	COAL (TON)	69,620	72,400	68,500	39,200	0	22,900	610,410
18.	NATURAL GAS (MCF)	12,946,375	13,064,755	12,552,694	12,301,864	10,004,504	10,476,895	131,115,049
19.	SOLAR	0	0	0	0	0	0	0
20.	OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)								
21.	HEAVY OIL	0	0	0	0	0	0	0
22.	LIGHT OIL	29,229	29,229	28,286	27,814	23,100	29,229	304,543
23.	COAL	1,566,500	1,628,890	1,541,230	881,930	0	515,150	13,733,780
24.	NATURAL GAS	13,272,901	13,397,591	12,863,054	12,597,076	10,281,630	10,751,851	134,413,197
25.	SOLAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**14,868,630**	**15,055,710**	**14,432,570**	**13,506,820**	**10,304,730**	**11,296,230**	**148,451,520**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.13	0.13	0.13	0.15	0.15	0.17	0.14
30.	COAL	6.28	6.53	6.51	4.13	0.00	2.57	5.54
31.	NATURAL GAS	86.20	86.28	86.90	88.51	93.00	90.60	86.46
32.	SOLAR	7.39	7.06	6.46	7.21	6.85	6.66	7.86
33.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34.	**TOTAL (%)**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT								
35.	HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36.	LIGHT OIL ($/BBL)	84.93	83.11	81.61	80.32	79.38	78.34	86.27
37.	COAL ($/TON)	79.85	79.69	79.73	79.69	0.00	79.72	77.74
38.	NATURAL GAS ($/MCF)	3.89	3.90	3.89	3.87	3.98	4.13	3.99
39.	SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)								
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	14.49	14.18	13.92	13.70	13.54	13.36	14.71
43.	COAL	3.55	3.54	3.54	3.54	0.00	3.54	3.46
44.	NATURAL GAS	3.80	3.80	3.79	3.78	3.87	4.03	3.89
45.	SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	**TOTAL ($/MMBTU)**	**3.79**	**3.79**	**3.78**	**3.78**	**3.89**	**4.03**	**3.87**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	10,996	10,996	10,998	10,998	11,000	10,996	10,997
50.	COAL	12,271	12,073	12,176	12,281	0	13,055	12,266
51.	NATURAL GAS	7,568	7,524	7,609	8,187	7,651	7,697	7,705
52.	SOLAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**7,308**	**7,295**	**7,418**	**7,770**	**7,131**	**7,327**	**7,357**
GENERATED FUEL COST PER KWH (CENTS/KWH)								
55.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56.	LIGHT OIL	15.93	15.59	15.31	15.07	14.89	14.70	16.18
57.	COAL	4.35	4.28	4.31	4.35	0.00	4.63	4.24
58.	NATURAL GAS	2.88	2.86	2.88	3.09	2.96	3.10	3.00
59.	SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	**TOTAL (CENTS/KWH)**	**2.77**	**2.77**	**2.81**	**2.94**	**2.77**	**2.95**	**2.85**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	270	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	190	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,880	258.1	-	258.1	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	9,810	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,160	18.4	-	18.4	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	12,360	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,420	18.6	-	18.6	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,710	18.9	-	18.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,460	19.6	-	19.6	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,500	17.7	-	17.7	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,530	20.7	-	20.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,290	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	9,870	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**97,450**	**20.1**	**-**	**20.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**350**	**10,510**	**4.0**	**79.5**	**31.3**	**14,473**	**GAS**	**147,970**	**1,027,979**	**152,110.0**	**662,536**	**6.30**	**4.48**
19. B.B.#3 (GAS)	355	26,940	10.2	-	-	-	GAS	310,060	1,027,995	318,740.0	1,388,294	5.15	4.48
20. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**355**	**26,940**	**10.2**	**83.2**	**52.7**	**11,831**		**-**	**-**	**318,740.0**	**1,388,294**	**5.15**	**-**
22. B.B.#4 (GAS)	160	5,630	4.7	-	-	-	GAS	70,330	1,027,869	72,290.0	314,903	5.59	4.48
23. B.B.#4 (COAL)	432	106,900	33.3	-	-	-	COAL	61,050	22,499,754	1,373,610.0	4,387,675	4.10	71.87
24. BIG BEND #4 TOTAL	**432**	**112,530**	**35.0**	**89.8**	**38.0**	**12,849**		**-**	**-**	**1,445,900.0**	**4,702,578**	**4.18**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	22,130	1,028,016	22,750.0	99,087	-	4.48
26. B.B.C.T.#4 TOTAL	**61**	**130**	**0.3**	**98.3**	**53.3**	**13,462**	**GAS**	**1,710**	**1,023,392**	**1,750.0**	**7,657**	**5.89**	**4.48**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,198**	**150,110**	**16.8**	**85.3**	**39.4**	**12,781**	**-**	**-**	**-**	**1,918,500.0**	**6,860,151**	**4.57**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	13,280	9.3	-	85.4	8,974	GAS	115,920	1,028,037	119,170.0	519,032	3.91	4.48
32. POLK #1 TOTAL	**220**	**13,280**	**8.1**	**93.4**	**85.4**	**8,974**	**-**	**-**	**-**	**119,170.0**	**519,032**	**3.91**	**-**
33. POLK #2 ST DUCT FIRING	120	1,700	1.9	-	74.6	8,194	GAS	13,550	1,028,044	13,930.0	60,670	3.57	4.48
34. POLK #2 ST W/O DUCT FIRING	360	629,243	-	-	-	-		4,228,075	1,028,019	4,346,541.4	18,931,211	3.01	4.48
35. POLK #2 ST TOTAL	**480**	**630,943**	**176.7**	**-**	**179.1**	**6,911**	**GAS**	**-**	**-**	**4,360,471.4**	**18,991,881**	**3.01**	**-**
36. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
37. POLK #2 CT (OIL)	187	1,329	1.0	-	5.9	10,996	LGT OIL	2,493	5,862,134	14,614.3	243,966	18.36	97.86
38. POLK #2 TOTAL (4)	**180**	**1,329**	**1.0**	**-**	**5.9**	**10,996**	**-**	**-**	**-**	**14,614.3**	**243,966**	**18.36**	**-**
39. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
40. POLK #3 CT (OIL)	187	1,329	1.0	-	80.2	10,996	LGT OIL	2,493	5,862,134	14,614.3	243,967	18.36	97.86
41. POLK #3 TOTAL (4)	**180**	**1,329**	**1.0**	**-**	**80.2**	**10,996**	**-**	**-**	**-**	**14,614.3**	**243,967**	**18.36**	**-**

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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
44. POLK #2 CC TOTAL	**1,200**	**633,601**	**71.0**	**97.0**	**153.9**	**6,928**	**-**	**-**	**-**	**4,389,700.0**	**19,479,814**	**3.07**	**-**
45. POLK STATION TOTAL	**1,420**	**646,881**	**61.2**	**96.5**	**148.0**	**6,970**	**-**	**-**	**-**	**4,508,870.0**	**19,998,846**	**3.09**	**-**
46. BAYSIDE #1	792	310,320	52.7	97.3	55.7	7,357	GAS	2,220,870	1,027,998	2,283,050.0	9,943,948	3.20	4.48
47. BAYSIDE #2	1,047	166,480	21.4	97.4	34.5	7,819	GAS	1,266,250	1,027,996	1,301,700.0	5,669,637	3.41	4.48
48. BAYSIDE #3	61	140	0.3	98.6	57.4	12,214	GAS	1,670	1,023,952	1,710.0	7,477	5.34	4.48
49. BAYSIDE #4	61	140	0.3	98.6	57.4	12,643	GAS	1,720	1,029,070	1,770.0	7,701	5.50	4.48
50. BAYSIDE #5	61	140	0.3	98.6	57.4	12,571	GAS	1,710	1,029,240	1,760.0	7,657	5.47	4.48
51. BAYSIDE #6	61	140	0.3	98.6	57.4	13,000	GAS	1,770	1,028,249	1,820.0	7,925	5.66	4.48
52. BAYSIDE STATION TOTAL	**2,083**	**477,360**	**30.8**	**97.5**	**45.9**	**7,524**	**GAS**	**3,493,990**	**1,027,997**	**3,591,810.0**	**15,644,345**	**3.28**	**4.48**
53. SYSTEM TOTAL	**5,353**	**1,371,801**	**34.4**	**82.6**	**79.6**	**7,304**	**-**	**-**	**-**	**10,019,180.0**	**42,503,342**	**3.10**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **ST = STEAM TURBINE**

(1) **As burned fuel cost system total includes ignition**
(2) **Fuel burned (MM BTU) system total excludes ignition**
(3) **AC rating**
(4) **In Simple Cycle Mode**

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 11 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	260	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	190	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,040	301.6	-	301.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	11,330	24.1	-	24.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	11,750	23.6	-	23.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	13,120	26.3	-	26.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	9,350	22.9	-	22.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	8,560	23.2	-	23.2	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,820	23.2	-	23.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	7,500	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	12,170	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	13,010	26.1	-	26.1	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,260	28.0	-	28.0	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**107,360**	**24.5**	**-**	**24.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**350**	**4,140**	**1.8**	**79.5**	**38.2**	**13,415**	**GAS**	**54,020**	**1,028,138**	**55,540.0**	**233,342**	**5.64**	**4.32**
19. B.B.#3 (GAS)	355	14,300	6.0	-	-	-	GAS	163,050	1,028,028	167,620.0	704,303	4.93	4.32
20. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**355**	**14,300**	**6.0**	**62.2**	**54.4**	**11,722**		**-**	**-**	**167,620.0**	**704,303**	**4.93**	**-**
22. B.B.#4 (GAS)	160	5,120	4.8	-	-	-	GAS	63,800	1,028,056	65,590.0	275,588	5.38	4.32
23. B.B.#4 (COAL)	432	97,280	33.5	-	-	-	COAL	55,390	22,498,646	1,246,200.0	4,136,102	4.25	74.67
24. BIG BEND #4 TOTAL	**432**	**102,400**	**35.3**	**89.8**	**38.3**	**12,810**		**-**	**-**	**1,311,790.0**	**4,411,690**	**4.31**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	10,020	1,027,944	10,300.0	43,282	-	4.32
26. B.B.C.T.#4 TOTAL	**61**	**640**	**1.6**	**98.3**	**52.5**	**12,781**	**GAS**	**7,950**	**1,028,931**	**8,180.0**	**34,340**	**5.37**	**4.32**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,198**	**121,480**	**15.1**	**79.0**	**39.7**	**12,703**	**-**	**-**	**-**	**1,543,130.0**	**5,426,957**	**4.47**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	85,450	66.2	-	85.9	8,870	GAS	737,320	1,028,007	757,970.0	3,184,893	3.73	4.32
32. POLK #1 TOTAL	**220**	**85,450**	**57.8**	**93.4**	**85.9**	**8,870**	**-**	**-**	**-**	**757,970.0**	**3,184,893**	**3.73**	**-**
33. POLK #2 ST DUCT FIRING	120	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. POLK #2 ST W/O DUCT FIRING	360	0	-	-	-	-		0	0	0.0	0	0.00	0.00
35. POLK #2 ST TOTAL	**480**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
36. POLK #2 CT (GAS)	180	37,830	31.3	-	66.9	11,520	GAS	423,940	1,028,023	435,820.0	1,831,232	4.84	4.32
37. POLK #2 CT (OIL)	187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
38. POLK #2 TOTAL (4)	**180**	**37,830**	**31.3**	**-**	**66.9**	**11,520**	**-**	**-**	**-**	**435,820.0**	**1,831,232**	**4.84**	**-**
39. POLK #3 CT (GAS)	180	23,620	19.5	-	71.3	11,282	GAS	259,230	1,028,006	266,490.0	1,119,758	4.74	4.32
40. POLK #3 CT (OIL)	187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
41. POLK #3 TOTAL (4)	**180**	**23,620**	**19.5**	**-**	**68.2**	**11,282**	**-**	**-**	**-**	**266,490.0**	**1,119,758**	**4.74**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL [4]	**180**	**16,600**	**13.7**	**-**	**73.2**	**11,175**	**GAS**	**180,450**	**1,027,986**	**185,500.0**	**779,463**	**4.70**	**4.32**
43. POLK #5 CT (GAS) TOTAL [4]	**180**	**14,580**	**12.1**	**-**	**73.6**	**11,169**	**GAS**	**158,410**	**1,027,965**	**162,840.0**	**684,261**	**4.69**	**4.32**
44. POLK #2 CC TOTAL	**1,200**	**92,630**	**11.5**	**0.0**	**69.3**	**11,342**	**-**	**-**	**-**	**1,050,650.0**	**4,414,714**	**4.77**	**-**
45. POLK STATION TOTAL	**1,420**	**178,080**	**18.7**	**14.5**	**76.1**	**10,156**	**-**	**-**	**-**	**1,808,620.0**	**7,599,607**	**4.27**	**-**
46. BAYSIDE #1	792	344,120	64.7	97.3	66.4	7,263	GAS	2,431,210	1,027,998	2,499,280.0	10,501,742	3.05	4.32
47. BAYSIDE #2	1,047	526,190	74.8	97.4	76.8	7,334	GAS	3,754,040	1,027,999	3,859,150.0	16,215,777	3.08	4.32
48. BAYSIDE #3	61	690	1.7	98.6	56.6	12,507	GAS	8,400	1,027,381	8,630.0	36,284	5.26	4.32
49. BAYSIDE #4	61	220	0.5	98.6	45.1	13,864	GAS	2,960	1,030,405	3,050.0	12,786	5.81	4.32
50. BAYSIDE #5	61	690	1.7	98.6	53.9	12,667	GAS	8,490	1,029,446	8,740.0	36,673	5.31	4.32
51. BAYSIDE #6	61	730	1.8	98.6	57.0	12,479	GAS	8,860	1,028,217	9,110.0	38,271	5.24	4.32
52. BAYSIDE STATION TOTAL	**2,083**	**872,640**	**62.3**	**97.5**	**72.3**	**7,320**	**GAS**	**6,213,960**	**1,028,001**	**6,387,960.0**	**26,841,533**	**3.08**	**4.32**
53. SYSTEM TOTAL	**5,353**	**1,279,560**	**35.6**	**59.5**	**72.7**	**7,612**	**-**	**-**	**-**	**9,739,710.0**	**39,868,097**	**3.12**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **ST = STEAM TURBINE**

[1] **As burned fuel cost system total includes ignition**
[2] **Fuel burned (MM BTU) system total excludes ignition**
[3] **AC rating**

[4] **In Simple Cycle Mode**

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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	330	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	250	1.7	-	1.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,070	365.2	-	365.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,310	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	13,800	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,360	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,100	24.6	-	24.6	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,160	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,310	29.9	-	29.9	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,810	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,550	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,460	31.6	-	31.6	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	12,740	28.7	-	28.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**134,250**	**27.7**	**-**	**27.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**350**	**24,620**	**9.5**	**79.5**	**48.8**	**12,375**	**GAS**	**296,360**	**1,028,040**	**304,670.0**	**1,231,894**	**5.00**	**4.16**
19. B.B.#3 (GAS)	355	41,630	15.8	-	-	-	GAS	464,470	1,027,989	477,470.0	1,930,684	4.64	4.16
20. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**400**	**41,630**	**14.0**	**83.2**	**52.8**	**11,469**		**-**	**-**	**477,470.0**	**1,930,684**	**4.64**	**-**
22. B.B.#4 (GAS)	160	3,010	2.5	-	-	-	GAS	35,460	1,027,919	36,450.0	147,398	4.90	4.16
23. B.B.#4 (COAL)	432	57,210	17.8	-	-	-	COAL	30,780	22,499,675	692,540.0	2,316,287	4.05	75.25
24. BIG BEND #4 TOTAL	**432**	**60,220**	**18.8**	**84.0**	**46.0**	**12,105**		**-**	**-**	**728,990.0**	**2,463,685**	**4.09**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	40,080	1,027,695	41,190.0	166,602	-	4.16
26. B.B.C.T.#4 TOTAL	**61**	**3,680**	**8.1**	**98.3**	**79.4**	**11,639**	**GAS**	**41,670**	**1,027,838**	**42,830.0**	**173,212**	**4.71**	**4.16**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,243**	**130,150**	**14.1**	**83.2**	**49.2**	**11,940**	**-**	**-**	**-**	**1,553,960.0**	**5,966,077**	**4.58**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	86,620	60.7	-	88.3	8,788	GAS	740,490	1,028,008	761,230.0	3,078,030	3.55	4.16
32. POLK #1 TOTAL	**220**	**86,620**	**53.0**	**93.4**	**88.3**	**8,788**	**-**	**-**	**-**	**761,230.0**	**3,078,030**	**3.55**	**-**
33. POLK #2 ST DUCT FIRING	120	10,320	11.6	-	82.7	8,171	GAS	82,030	1,027,917	84,320.0	340,978	3.30	4.16
34. POLK #2 ST W/O DUCT FIRING	360	265,933	-	-	-	-		1,780,235	1,028,050	1,830,171.4	7,399,987	2.78	4.16
35. POLK #2 ST TOTAL	**480**	**276,253**	**77.5**	**-**	**132.3**	**6,930**	**GAS**	**-**	**-**	**1,914,491.4**	**7,740,965**	**2.80**	**-**
36. POLK #2 CT (GAS)	180	32,760	24.5	-	76.5	11,028	GAS	351,430	1,028,028	361,280.0	1,460,805	4.46	4.16
37. POLK #2 CT (OIL)	187	1,329	1.0	-	5.8	10,996	LGT OIL	2,493	5,862,134	14,614.3	235,482	17.72	94.46
38. POLK #2 TOTAL (4)	**180**	**34,089**	**25.5**	**-**	**51.8**	**11,027**	**-**	**-**	**-**	**375,894.3**	**1,696,287**	**4.98**	**-**
39. POLK #3 CT (GAS)	180	21,650	16.2	-	78.1	10,998	GAS	231,630	1,027,976	238,110.0	962,827	4.45	4.16
40. POLK #3 CT (OIL)	187	1,329	1.0	-	80.2	10,996	LGT OIL	2,493	5,862,134	14,614.3	235,483	17.72	94.46
41. POLK #3 TOTAL (4)	**180**	**22,979**	**17.2**	**-**	**78.2**	**10,998**	**-**	**-**	**-**	**252,724.3**	**1,198,310**	**5.21**	**-**

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 14 OF 42

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2021

(A) PLANT/UNIT		(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL	(4)	**180**	**22,020**	**16.5**	**-**	**79.4**	**10,930**	**GAS**	**234,120**	**1,027,977**	**240,670.0**	**973,178**	**4.42**	**4.16**
43. POLK #5 CT (GAS) TOTAL	(4)	**180**	**12,440**	**9.3**	**-**	**84.3**	**10,765**	**GAS**	**130,270**	**1,028,019**	**133,920.0**	**541,499**	**4.35**	**4.16**
44. POLK #2 CC TOTAL		**1,200**	**367,781**	**41.2**	**43.8**	**90.5**	**7,933**	**-**	**-**	**-**	**2,917,700.0**	**12,150,239**	**3.30**	**-**
45. POLK STATION TOTAL		**1,420**	**454,401**	**43.1**	**51.5**	**89.8**	**8,096**	**-**	**-**	**-**	**3,678,930.0**	**15,228,269**	**3.35**	**-**
46. BAYSIDE #1		792	196,880	33.5	53.4	64.2	7,281	GAS	1,394,520	1,028,002	1,433,570.0	5,796,667	2.94	4.16
47. BAYSIDE #2		1,047	508,400	65.4	97.4	68.2	7,392	GAS	3,655,630	1,027,998	3,757,980.0	15,195,529	2.99	4.16
48. BAYSIDE #3		61	2,290	5.1	79.5	81.6	11,563	GAS	25,760	1,027,950	26,480.0	107,078	4.68	4.16
49. BAYSIDE #4		61	4,160	9.2	89.1	85.2	11,397	GAS	46,110	1,028,193	47,410.0	191,668	4.61	4.16
50. BAYSIDE #5		61	4,390	9.7	98.6	76.6	11,713	GAS	50,010	1,028,194	51,420.0	207,879	4.74	4.16
51. BAYSIDE #6		61	4,810	10.6	98.6	77.3	11,688	GAS	54,700	1,027,788	56,220.0	227,374	4.73	4.16
52. BAYSIDE STATION TOTAL		**2,083**	**720,930**	**46.6**	**80.0**	**67.3**	**7,453**	**GAS**	**5,226,730**	**1,028,000**	**5,373,080.0**	**21,726,195**	**3.01**	**4.16**
53. SYSTEM TOTAL		**5,398**	**1,439,731**	**35.9**	**63.6**	**83.8**	**7,367**	**-**	**-**	**-**	**10,605,970.0**	**42,920,541**	**2.98**	**-**

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE
CT = COMBUSTION TURBINE
ST = STEAM TURBINE

(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) AC rating
(4) In Simple Cycle Mode

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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	320	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	300	2.2	-	2.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,630	428.7	-	428.7	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	17,360	34.4	-	34.4	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	18,090	33.9	-	33.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	19,590	36.6	-	36.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	14,580	33.3	-	33.3	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	13,310	33.7	-	33.7	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	9,230	34.3	-	34.3	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	11,590	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	18,770	34.9	-	34.9	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	19,680	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	16,350	38.0	-	38.0	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**163,800**	**34.9**	**-**	**34.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**13,080**	**5.3**	**45.1**	**38.9**	**13,578**	**GAS**	**172,760**	**1,028,016**	**177,600.0**	**668,882**	**5.11**	**3.87**
19. B.B.#3 (GAS)	345	50,680	20.4	-	-	-	GAS	582,600	1,027,995	598,910.0	2,255,678	4.45	3.87
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**50,680**	**20.4**	**83.2**	**56.3**	**11,817**		**-**	**-**	**598,910.0**	**2,255,678**	**4.45**	**-**
22. B.B.#4 (GAS)	155	3,880	3.5	-	-	-	GAS	47,120	1,028,014	48,440.0	182,437	4.70	3.87
23. B.B.#4 (COAL)	422	73,730	24.3	-	-	-	COAL	40,910	22,500,367	920,490.0	3,167,903	4.30	77.44
24. BIG BEND #4 TOTAL	**422**	**77,610**	**25.5**	**53.9**	**43.8**	**12,485**		**-**	**-**	**968,930.0**	**3,350,340**	**4.32**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	37,990	1,027,639	39,040.0	147,088	-	3.87
26. B.B.C.T.#4 TOTAL	**56**	**1,270**	**3.1**	**78.6**	**63.0**	**13,039**	**GAS**	**16,110**	**1,027,933**	**16,560.0**	**62,374**	**4.91**	**3.87**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,163**	**142,640**	**17.0**	**61.2**	**47.1**	**12,353**	**-**	**-**	**-**	**1,762,000.0**	**6,484,362**	**4.55**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	56,260	40.7	-	89.1	8,870	GAS	485,420	1,027,996	499,010.0	1,879,422	3.34	3.87
32. POLK #1 TOTAL	**220**	**56,260**	**35.5**	**93.4**	**89.1**	**8,870**	**-**	**-**	**-**	**499,010.0**	**1,879,422**	**3.34**	**-**
33. POLK #2 ST DUCT FIRING	120	16,580	19.2	-	59.6	8,273	GAS	133,420	1,028,032	137,160.0	516,568	3.12	3.87
34. POLK #2 ST W/O DUCT FIRING	341	495,129	-	-	-	-		3,320,823	1,028,021	3,413,874.3	12,857,379	2.60	3.87
35. POLK #2 ST TOTAL	**461**	**511,709**	**154.2**	**-**	**118.3**	**6,940**	**GAS**	**-**	**-**	**3,551,034.3**	**13,373,947**	**2.61**	**-**
36. POLK #2 CT (GAS)	150	270	0.3	-	90.0	11,333	GAS	2,980	1,026,846	3,060.0	11,538	4.27	3.87
37. POLK #2 CT (OIL)	159	986	0.9	-	5.0	10,997	LGT OIL	1,849	5,864,197	10,842.9	170,426	17.28	92.17
38. POLK #2 TOTAL (4)	**150**	**1,256**	**1.2**	**-**	**6.3**	**11,069**	**-**	**-**	**-**	**13,902.9**	**181,964**	**14.49**	**-**
39. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
40. POLK #3 CT (OIL)	159	986	0.9	-	94.4	10,997	LGT OIL	1,849	5,864,197	10,842.9	170,426	17.28	92.17
41. POLK #3 TOTAL (4)	**150**	**986**	**0.9**	**-**	**94.4**	**10,997**	**-**	**-**	**-**	**10,842.9**	**170,426**	**17.28**	**-**

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EXHIBIT NO. MAS-3
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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
44. POLK #2 CC TOTAL	**1,061**	**513,951**	**67.3**	**97.0**	**105.1**	**6,957**	**-**	**-**	**-**	**3,575,780.1**	**13,726,337**	**2.67**	**-**
45. POLK STATION TOTAL	**1,281**	**570,211**	**61.8**	**96.4**	**101.3**	**7,146**	**-**	**-**	**-**	**4,074,790.1**	**15,605,759**	**2.74**	**-**
46. BAYSIDE #1	720	306,890	59.2	97.3	60.9	7,453	GAS	2,224,950	1,027,992	2,287,230.0	8,614,438	2.81	3.87
47. BAYSIDE #2	954	367,430	53.5	97.4	55.7	7,579	GAS	2,708,750	1,027,998	2,784,590.0	10,487,589	2.85	3.87
48. BAYSIDE #3	56	2,730	6.8	98.6	66.8	12,784	GAS	33,940	1,028,285	34,900.0	131,407	4.81	3.87
49. BAYSIDE #4	56	2,030	5.0	88.7	64.7	12,936	GAS	25,550	1,027,789	26,260.0	98,923	4.87	3.87
50. BAYSIDE #5	56	2,230	5.5	78.9	76.6	12,184	GAS	26,440	1,027,610	27,170.0	102,369	4.59	3.87
51. BAYSIDE #6	56	2,380	5.9	78.9	64.4	12,920	GAS	29,930	1,027,397	30,750.0	115,881	4.87	3.87
52. BAYSIDE STATION TOTAL	**1,898**	**683,690**	**50.0**	**96.1**	**58.0**	**7,592**	**GAS**	**5,049,560**	**1,027,991**	**5,190,900.0**	**19,550,607**	**2.86**	**3.87**
53. SYSTEM TOTAL	**4,994**	**1,560,341**	**43.4**	**75.5**	**84.7**	**7,067**	**-**	**-**	**-**	**11,027,690.1**	**41,640,728**	**2.67**	**-**

LEGEND:
B.B. = BIG BEND — **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE — **ST = STEAM TURBINE**

[1] **As burned fuel cost system total includes ignition**
[2] **Fuel burned (MM BTU) system total excludes ignition**
[3] **AC rating**
[4] **In Simple Cycle Mode**

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	340	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	320	2.2	-	2.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	5,000	448.0	-	448.0	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	19,500	37.4	-	37.4	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	20,300	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	20,410	36.9	-	36.9	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	16,320	36.1	-	36.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	14,880	36.5	-	36.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	10,050	36.1	-	36.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	12,960	35.3	-	35.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	20,250	36.4	-	36.4	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	20,490	37.1	-	37.1	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	18,450	41.5	-	41.5	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**179,270**	**36.9**	**-**	**36.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**35,260**	**13.9**	**77.0**	**50.6**	**12,455**	**GAS**	**427,190**	**1,028,020**	**439,160.0**	**1,641,194**	**4.65**	**3.84**
19. B.B.#3 (GAS)	345	58,500	22.8	-	-	-	GAS	658,410	1,027,992	676,840.0	2,529,503	4.32	3.84
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**395**	**58,500**	**19.9**	**83.2**	**53.3**	**11,570**		**-**	**-**	**676,840.0**	**2,529,503**	**4.32**	**-**
22. B.B.#4 (GAS)	155	7,740	6.7	-	-	-	GAS	88,790	1,028,044	91,280.0	341,117	4.41	3.84
23. B.B.#4 (COAL)	422	147,030	46.8	-	-	-	COAL	77,080	22,499,741	1,734,280.0	5,971,387	4.06	77.47
24. BIG BEND #4 TOTAL	**422**	**154,770**	**49.3**	**89.8**	**53.5**	**11,795**		**-**	**-**	**1,825,560.0**	**6,312,504**	**4.08**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	40,080	1,027,944	41,200.0	153,981	-	3.84
26. B.B.C.T.#4 TOTAL	**56**	**3,960**	**9.5**	**98.3**	**88.4**	**11,646**	**GAS**	**44,870**	**1,027,858**	**46,120.0**	**172,383**	**4.35**	**3.84**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,213**	**252,490**	**28.0**	**84.4**	**53.3**	**11,833**	**-**	**-**	**-**	**2,987,680.0**	**10,809,565**	**4.28**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	46,790	32.8	-	92.0	8,827	GAS	401,760	1,028,002	413,010.0	1,543,496	3.30	3.84
32. POLK #1 TOTAL	**220**	**46,790**	**28.6**	**51.2**	**92.0**	**8,827**	**-**	**-**	**-**	**413,010.0**	**1,543,496**	**3.30**	**-**
33. POLK #2 ST DUCT FIRING	120	32,620	36.5	-	79.7	8,276	GAS	262,610	1,028,026	269,970.0	1,008,905	3.09	3.84
34. POLK #2 ST W/O DUCT FIRING	341	589,513	-	-	-	-		3,953,635	1,028,021	4,064,421.4	15,189,218	2.58	3.84
35. POLK #2 ST TOTAL	**461**	**622,133**	**181.4**	**-**	**125.8**	**6,967**	**GAS**	**-**	**-**	**4,334,391.4**	**16,198,123**	**2.60**	**-**
36. POLK #2 CT (GAS)	150	1,730	1.6	-	96.1	10,786	GAS	18,150	1,028,099	18,660.0	69,729	4.03	3.84
37. POLK #2 CT (OIL)	159	1,329	1.1	-	6.8	10,996	LGT OIL	2,493	5,862,134	14,614.3	222,824	16.77	89.38
38. POLK #2 TOTAL (4)	**150**	**3,059**	**2.7**	**-**	**14.2**	**10,878**	**-**	**-**	**-**	**33,274.3**	**292,553**	**9.56**	**-**
39. POLK #3 CT (GAS)	150	1,740	1.6	-	96.7	10,782	GAS	18,250	1,027,945	18,760.0	70,114	4.03	3.84
40. POLK #3 CT (OIL)	159	1,329	1.1	-	94.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	222,824	16.77	89.38
41. POLK #3 TOTAL (4)	**150**	**3,069**	**2.8**	**-**	**95.7**	**10,875**	**-**	**-**	**-**	**33,374.3**	**292,938**	**9.55**	**-**

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 18 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL [4]	**150**	**1,440**	**1.3**	**-**	**96.0**	**10,806**	**GAS**	**15,140**	**1,027,741**	**15,560.0**	**58,165**	**4.04**	**3.84**
44. POLK #2 CC TOTAL	**1,061**	**629,701**	**79.8**	**97.0**	**112.8**	**7,014**	**-**	**-**	**-**	**4,416,600.0**	**16,841,779**	**2.67**	**-**
45. POLK STATION TOTAL	**1,281**	**676,491**	**71.0**	**89.1**	**109.1**	**7,139**	**-**	**-**	**-**	**4,829,610.0**	**18,385,275**	**2.72**	**-**
46. BAYSIDE #1	720	317,050	59.2	97.3	61.7	7,444	GAS	2,295,850	1,028,007	2,360,150.0	8,820,280	2.78	3.84
47. BAYSIDE #2	954	350,300	49.4	97.4	51.0	7,607	GAS	2,592,180	1,028,003	2,664,770.0	9,958,731	2.84	3.84
48. BAYSIDE #3	56	7,690	18.5	98.6	96.7	11,446	GAS	85,630	1,027,911	88,020.0	328,976	4.28	3.84
49. BAYSIDE #4	56	6,370	15.3	98.6	97.2	11,419	GAS	70,750	1,028,127	72,740.0	271,810	4.27	3.84
50. BAYSIDE #5	56	10,620	25.5	98.6	96.3	11,414	GAS	117,910	1,028,072	121,220.0	452,991	4.27	3.84
51. BAYSIDE #6	56	8,900	21.4	79.5	96.3	11,447	GAS	99,110	1,027,949	101,880.0	380,764	4.28	3.84
52. BAYSIDE STATION TOTAL	**1,898**	**700,930**	**49.6**	**97.0**	**56.7**	**7,717**	**GAS**	**5,261,430**	**1,028,006**	**5,408,780.0**	**20,213,552**	**2.88**	**3.84**
53. SYSTEM TOTAL	**5,044**	**1,809,181**	**48.2**	**79.4**	**86.9**	**7,311**	**-**	**-**	**-**	**13,226,070.0**	**49,408,392**	**2.73**	**-**

LEGEND:
B.B. = BIG BEND — **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE — **ST = STEAM TURBINE**

[1] As burned fuel cost system total includes ignition
[2] Fuel burned (MM BTU) system total excludes ignition
[3] AC rating
[4] In Simple Cycle Mode

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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2021

(A) PLANT/UNIT		(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR		1.6	290	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR		19.3	290	2.1	-	2.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR		1.5	4,430	410.2	-	410.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR		70.1	16,850	33.4	-	33.4	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR		74.2	17,490	32.7	-	32.7	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR		74.3	17,510	32.7	-	32.7	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR		60.8	14,070	32.1	-	32.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR		54.8	12,850	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR		37.4	8,720	32.4	-	32.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR		49.4	11,160	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR		74.7	16,630	30.9	-	30.9	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR		74.3	17,580	32.9	-	32.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR		59.8	16,300	37.9	-	37.9	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR		-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR		-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL	(3)	**652.2**	**154,170**	**32.8**	**-**	**32.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL		**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL		**340**	**24,930**	**10.2**	**79.5**	**49.9**	**12,500**	**GAS**	**303,150**	**1,027,973**	**311,630.0**	**1,170,680**	**4.70**	**3.86**
19. B.B.#3 (GAS)		345	70,120	28.2	-	-	-	GAS	791,310	1,027,992	813,460.0	3,055,817	4.36	3.86
20. B.B.#3 (COAL)		395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL		**345**	**70,120**	**28.2**	**83.2**	**60.3**	**11,601**		**-**	**-**	**813,460.0**	**3,055,817**	**4.36**	**-**
22. B.B.#4 (GAS)		155	7,220	6.5	-	-	-	GAS	83,610	1,027,867	85,940.0	322,878	4.47	3.86
23. B.B.#4 (COAL)		422	137,100	45.1	-	-	-	COAL	72,580	22,498,760	1,632,960.0	5,734,099	4.18	79.00
24. BIG BEND #4 TOTAL		**422**	**144,320**	**47.5**	**89.8**	**51.5**	**11,910**		**-**	**-**	**1,718,900.0**	**6,056,977**	**4.20**	**-**
25. B.B. IGNITION		-	-	-	-	-	-	GAS	37,160	1,027,987	38,200.0	143,501	-	3.86
26. B.B.C.T.#4 TOTAL		**56**	**4,080**	**10.1**	**98.3**	**85.7**	**11,708**	**GAS**	**46,480**	**1,027,754**	**47,770.0**	**179,493**	**4.40**	**3.86**
27. B.B.C.T.#5 TOTAL		**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL		**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL		**1,163**	**243,450**	**29.1**	**85.2**	**54.0**	**11,878**	**-**	**-**	**-**	**2,891,760.0**	**10,606,468**	**4.36**	**-**
30. POLK #1 GASIFIER		220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)		192	81,120	58.7	-	92.5	8,813	GAS	695,460	1,028,010	714,940.0	2,685,671	3.31	3.86
32. POLK #1 TOTAL		**220**	**81,120**	**51.2**	**93.4**	**92.5**	**8,813**	**-**	**-**	**-**	**714,940.0**	**2,685,671**	**3.31**	**-**
33. POLK #2 ST DUCT FIRING		120	37,820	43.8	-	91.1	8,274	GAS	304,400	1,028,022	312,930.0	1,175,507	3.11	3.86
34. POLK #2 ST W/O DUCT FIRING		341	639,929	-	-	-	-		4,294,634	1,028,019	4,414,964.3	16,584,667	2.59	3.86
35. POLK #2 ST TOTAL		**461**	**677,749**	**204.2**	**-**	**139.4**	**6,976**	**GAS**	**-**	**-**	**4,727,894.3**	**17,760,174**	**2.62**	**-**
36. POLK #2 CT (GAS)		150	1,630	1.5	-	98.8	10,755	GAS	17,050	1,028,152	17,530.0	65,842	4.04	3.86
37. POLK #2 CT (OIL)		159	1,286	1.1	-	6.5	10,998	LGT OIL	2,412	5,863,557	14,142.9	209,958	16.33	87.05
38. POLK #2 TOTAL	(4)	**150**	**2,916**	**2.7**	**-**	**13.6**	**10,862**	**-**	**-**	**-**	**31,672.9**	**275,800**	**9.46**	**-**
39. POLK #3 CT (GAS)		150	1,630	1.5	-	98.8	10,779	GAS	17,090	1,028,087	17,570.0	65,997	4.05	3.86
40. POLK #3 CT (OIL)		159	1,286	1.1	-	94.4	10,998	LGT OIL	2,412	5,863,557	14,142.9	209,958	16.33	87.05
41. POLK #3 TOTAL	(4)	**150**	**2,916**	**2.7**	**-**	**96.8**	**10,875**	**-**	**-**	**-**	**31,712.9**	**275,955**	**9.46**	**-**

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 20 OF 42

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL (4)	**150**	**1,630**	**1.5**	**-**	**98.8**	**10,755**	**GAS**	**17,050**	**1,028,152**	**17,530.0**	**65,842**	**4.04**	**3.86**
43. POLK #5 CT (GAS) TOTAL (4)	**150**	**1,500**	**1.4**	**-**	**100.0**	**10,673**	**GAS**	**15,580**	**1,027,599**	**16,010.0**	**60,166**	**4.01**	**3.86**
44. POLK #2 CC TOTAL	**1,061**	**686,711**	**89.9**	**97.0**	**124.1**	**7,026**	**-**	**-**	**-**	**4,824,820.1**	**18,437,937**	**2.68**	**-**
45. POLK STATION TOTAL	**1,281**	**767,831**	**83.2**	**96.4**	**115.6**	**7,215**	**-**	**-**	**-**	**5,539,760.1**	**21,123,608**	**2.75**	**-**
46. BAYSIDE #1	720	309,650	59.7	97.3	62.8	7,434	GAS	2,239,190	1,027,997	2,301,880.0	8,647,121	2.79	3.86
47. BAYSIDE #2	954	446,860	65.1	97.4	67.0	7,473	GAS	3,248,430	1,027,998	3,339,380.0	12,544,523	2.81	3.86
48. BAYSIDE #3	56	5,720	14.2	98.6	92.9	11,523	GAS	64,120	1,027,916	65,910.0	247,613	4.33	3.86
49. BAYSIDE #4	56	5,150	12.8	98.6	92.9	11,505	GAS	57,640	1,027,932	59,250.0	222,589	4.32	3.86
50. BAYSIDE #5	56	8,230	20.4	98.6	93.6	11,467	GAS	91,810	1,027,884	94,370.0	354,544	4.31	3.86
51. BAYSIDE #6	56	6,590	16.3	98.6	92.7	11,517	GAS	73,840	1,027,898	75,900.0	285,149	4.33	3.86
52. BAYSIDE STATION TOTAL	**1,898**	**782,200**	**57.2**	**97.5**	**65.9**	**7,590**	**GAS**	**5,775,030**	**1,027,993**	**5,936,690.0**	**22,301,539**	**2.85**	**3.86**
53. SYSTEM TOTAL	**4,994**	**1,947,651**	**54.2**	**81.6**	**95.0**	**7,377**	**-**	**-**	**-**	**14,368,210.1**	**54,031,615**	**2.77**	**-**

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE
CT = COMBUSTION TURBINE
ST = STEAM TURBINE

(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) AC rating
(4) In Simple Cycle Mode

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 21 OF 42

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	290	2.0	-	2.0	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,280	383.5	-	383.5	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,340	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,950	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,310	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,640	30.2	-	30.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,450	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,490	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,810	29.4	-	29.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,390	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,360	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	15,850	35.6	-	35.6	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**150,450**	**31.0**	**-**	**31.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**29,110**	**11.5**	**79.5**	**48.1**	**12,647**	**GAS**	**358,120**	**1,027,979**	**368,140.0**	**1,394,869**	**4.79**	**3.89**
19. B.B.#3 (GAS)	345	59,490	23.2	-	-	-	GAS	676,860	1,027,997	695,810.0	2,636,354	4.43	3.89
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**59,490**	**23.2**	**83.2**	**58.5**	**11,696**		**-**	**-**	**695,810.0**	**2,636,354**	**4.43**	**-**
22. B.B.#4 (GAS)	155	6,710	5.8	-	-	-	GAS	80,200	1,028,055	82,450.0	312,377	4.66	3.89
23. B.B.#4 (COAL)	422	127,660	40.7	-	-	-	COAL	69,620	22,500,718	1,566,500.0	5,559,374	4.35	79.85
24. BIG BEND #4 TOTAL	**422**	**134,370**	**42.8**	**89.8**	**46.4**	**12,272**		**-**	**-**	**1,648,950.0**	**5,871,751**	**4.37**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	35,070	1,027,944	36,050.0	136,597	-	3.89
26. B.B.C.T.#4 TOTAL	**56**	**3,140**	**7.5**	**98.3**	**83.7**	**11,815**	**GAS**	**36,090**	**1,027,986**	**37,100.0**	**140,570**	**4.48**	**3.89**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,163**	**226,110**	**26.1**	**85.2**	**49.6**	**12,162**	**-**	**-**	**-**	**2,750,000.0**	**10,180,142**	**4.50**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	53,670	37.6	-	92.0	8,840	GAS	461,500	1,027,996	474,420.0	1,797,532	3.35	3.89
32. POLK #1 TOTAL	**220**	**53,670**	**32.8**	**93.4**	**92.0**	**8,840**	**-**	**-**	**-**	**474,420.0**	**1,797,532**	**3.35**	**-**
33. POLK #2 ST DUCT FIRING	120	30,060	33.7	-	91.8	8,276	GAS	242,000	1,027,975	248,770.0	942,585	3.14	3.89
34. POLK #2 ST W/O DUCT FIRING	341	660,143	-	-	-	-		4,430,135	1,028,019	4,554,261.4	17,255,276	2.61	3.89
35. POLK #2 ST TOTAL	**461**	**690,203**	**201.2**	**-**	**149.0**	**6,959**	**GAS**	**-**	**-**	**4,803,031.4**	**18,197,861**	**2.64**	**-**
36. POLK #2 CT (GAS)	150	750	0.7	-	100.0	10,933	GAS	7,980	1,027,569	8,200.0	31,082	4.14	3.89
37. POLK #2 CT (OIL)	159	1,329	1.1	-	6.6	10,996	LGT OIL	2,493	5,862,134	14,614.3	211,721	15.93	84.93
38. POLK #2 TOTAL (4)	**150**	**2,079**	**1.9**	**-**	**10.0**	**10,974**	**-**	**-**	**-**	**22,814.3**	**242,803**	**11.68**	**-**
39. POLK #3 CT (GAS)	150	750	0.7	-	100.0	10,693	GAS	7,800	1,028,205	8,020.0	30,381	4.05	3.90
40. POLK #3 CT (OIL)	159	1,329	1.1	-	94.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	211,721	15.93	84.93
41. POLK #3 TOTAL (4)	**150**	**2,079**	**1.9**	**-**	**96.3**	**10,887**	**-**	**-**	**-**	**22,634.3**	**242,102**	**11.65**	**-**

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 22 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL (4)	**150**	**450**	**0.4**	**-**	**100.0**	**10,889**	**GAS**	**4,770**	**1,027,254**	**4,900.0**	**18,579**	**4.13**	**3.89**
43. POLK #5 CT (GAS) TOTAL (4)	**150**	**450**	**0.4**	**-**	**100.0**	**10,711**	**GAS**	**4,690**	**1,027,719**	**4,820.0**	**18,267**	**4.06**	**3.89**
44. POLK #2 CC TOTAL	**1,061**	**695,261**	**88.1**	**97.0**	**132.3**	**6,988**	**-**	**-**	**-**	**4,858,200.0**	**18,719,612**	**2.69**	**-**
45. POLK STATION TOTAL	**1,281**	**748,931**	**78.6**	**96.4**	**123.9**	**7,120**	**-**	**-**	**-**	**5,332,620.0**	**20,517,144**	**2.74**	**-**
46. BAYSIDE #1	720	429,780	80.2	97.3	82.9	7,307	GAS	3,054,720	1,028,003	3,140,260.0	11,898,066	2.77	3.89
47. BAYSIDE #2	954	463,520	65.3	97.4	67.1	7,466	GAS	3,366,230	1,027,999	3,460,480.0	13,111,391	2.83	3.89
48. BAYSIDE #3	56	3,760	9.0	98.6	88.3	11,705	GAS	42,810	1,028,031	44,010.0	166,744	4.43	3.89
49. BAYSIDE #4	56	3,240	7.8	98.6	91.8	11,608	GAS	36,590	1,027,876	37,610.0	142,517	4.40	3.89
50. BAYSIDE #5	56	4,470	10.7	98.6	84.9	11,707	GAS	50,900	1,028,094	52,330.0	198,254	4.44	3.89
51. BAYSIDE #6	56	4,400	10.6	98.6	87.3	11,664	GAS	49,910	1,028,251	51,320.0	194,398	4.42	3.89
52. BAYSIDE STATION TOTAL	**1,898**	**909,170**	**64.4**	**97.5**	**74.1**	**7,464**	**GAS**	**6,601,160**	**1,028,003**	**6,786,010.0**	**25,711,370**	**2.83**	**3.89**
53. SYSTEM TOTAL	**4,994**	**2,034,661**	**54.8**	**81.6**	**99.0**	**7,308**	**-**	**-**	**-**	**14,868,630.0**	**56,408,656**	**2.77**	**-**

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE
CT = COMBUSTION TURBINE
ST = STEAM TURBINE

(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) AC rating
(4) In Simple Cycle Mode

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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	270	1.9	-	1.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,200	376.3	-	376.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	15,770	30.2	-	30.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,350	29.6	-	29.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	16,730	30.3	-	30.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,170	29.1	-	29.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,040	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,360	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,430	28.4	-	28.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	15,880	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	16,780	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	15,370	34.5	-	34.5	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**145,640**	**30.0**	**-**	**30.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**24,310**	**9.6**	**79.5**	**50.0**	**12,492**	**GAS**	**295,410**	**1,028,029**	**303,690.0**	**1,152,050**	**4.74**	**3.90**
19. B.B.#3 (GAS)	345	53,240	20.7	-	-	-	GAS	598,140	1,027,987	614,880.0	2,332,647	4.38	3.90
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**53,240**	**20.7**	**83.2**	**61.5**	**11,549**		**-**	**-**	**614,880.0**	**2,332,647**	**4.38**	**-**
22. B.B.#4 (GAS)	155	7,100	6.2	-	-	-	GAS	83,390	1,028,061	85,730.0	325,207	4.58	3.90
23. B.B.#4 (COAL)	422	134,920	43.0	-	-	-	COAL	72,400	22,498,481	1,628,890.0	5,769,559	4.28	79.69
24. BIG BEND #4 TOTAL	**422**	**142,020**	**45.2**	**89.8**	**49.1**	**12,073**		**-**	**-**	**1,714,620.0**	**6,094,766**	**4.29**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	32,150	1,027,994	33,050.0	125,380	-	3.90
26. B.B.C.T.#4 TOTAL	**56**	**4,230**	**10.2**	**98.3**	**87.8**	**11,636**	**GAS**	**47,870**	**1,028,201**	**49,220.0**	**186,685**	**4.41**	**3.90**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,163**	**223,800**	**25.9**	**85.2**	**52.1**	**11,986**	**-**	**-**	**-**	**2,682,410.0**	**9,891,529**	**4.42**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	51,990	36.4	-	92.1	8,831	GAS	446,620	1,028,010	459,130.0	1,741,745	3.35	3.90
32. POLK #1 TOTAL	**220**	**51,990**	**31.8**	**93.4**	**92.1**	**8,831**	**-**	**-**	**-**	**459,130.0**	**1,741,745**	**3.35**	**-**
33. POLK #2 ST DUCT FIRING	120	33,210	37.2	-	92.3	8,274	GAS	267,300	1,027,984	274,780.0	1,042,426	3.14	3.90
34. POLK #2 ST W/O DUCT FIRING	341	662,953	-	-	-	-		4,449,515	1,028,020	4,574,191.4	17,352,377	2.62	3.90
35. POLK #2 ST TOTAL	**461**	**696,163**	**203.0**	**-**	**146.3**	**6,965**	**GAS**	**-**	**-**	**4,848,971.4**	**18,394,803**	**2.64**	**-**
36. POLK #2 CT (GAS)	150	1,620	1.5	-	90.0	11,025	GAS	17,370	1,028,210	17,860.0	67,740	4.18	3.90
37. POLK #2 CT (OIL)	159	1,329	1.1	-	6.6	10,996	LGT OIL	2,493	5,862,134	14,614.3	207,203	15.59	83.11
38. POLK #2 TOTAL (4)	**150**	**2,949**	**2.6**	**-**	**13.4**	**11,012**	**-**	**-**	**-**	**32,474.3**	**274,943**	**9.32**	**-**
39. POLK #3 CT (GAS)	150	300	0.3	-	100.0	11,000	GAS	3,210	1,028,037	3,300.0	12,518	4.17	3.90
40. POLK #3 CT (OIL)	159	1,329	1.1	-	94.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	207,202	15.59	83.11
41. POLK #3 TOTAL (4)	**150**	**1,629**	**1.5**	**-**	**95.4**	**10,997**	**-**	**-**	**-**	**17,914.3**	**219,720**	**13.49**	**-**

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 24 OF 42

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL (4)	**150**	**300**	**0.3**	**-**	**100.0**	**10,733**	**GAS**	**3,130**	**1,028,754**	**3,220.0**	**12,206**	**4.07**	**3.90**
43. POLK #5 CT (GAS) TOTAL (4)	**150**	**150**	**0.1**	**-**	**100.0**	**11,333**	**GAS**	**1,660**	**1,024,096**	**1,700.0**	**6,474**	**4.32**	**3.90**
44. POLK #2 CC TOTAL	**1,061**	**701,191**	**88.8**	**97.0**	**130.1**	**6,994**	**-**	**-**	**-**	**4,904,280.0**	**18,908,146**	**2.70**	**-**
45. POLK STATION TOTAL	**1,281**	**753,181**	**79.0**	**96.4**	**122.6**	**7,121**	**-**	**-**	**-**	**5,363,410.0**	**20,649,891**	**2.74**	**-**
46. BAYSIDE #1	720	444,350	83.0	97.3	85.2	7,295	GAS	3,153,270	1,028,000	3,241,560.0	12,297,234	2.77	3.90
47. BAYSIDE #2	954	478,130	67.4	97.4	71.8	7,427	GAS	3,454,270	1,028,000	3,550,990.0	13,471,085	2.82	3.90
48. BAYSIDE #3	56	4,330	10.4	98.6	92.0	11,605	GAS	48,890	1,027,818	50,250.0	190,663	4.40	3.90
49. BAYSIDE #4	56	3,120	7.5	98.6	94.4	11,567	GAS	35,110	1,027,912	36,090.0	136,923	4.39	3.90
50. BAYSIDE #5	56	6,320	15.2	98.6	88.9	11,582	GAS	71,230	1,027,657	73,200.0	277,785	4.40	3.90
51. BAYSIDE #6	56	5,000	12.0	98.6	92.0	11,560	GAS	56,220	1,028,104	57,800.0	219,249	4.38	3.90
52. BAYSIDE STATION TOTAL	**1,898**	**941,250**	**66.7**	**97.5**	**77.9**	**7,447**	**GAS**	**6,818,990**	**1,027,995**	**7,009,890.0**	**26,592,939**	**2.83**	**3.90**
53. SYSTEM TOTAL	**4,994**	**2,063,871**	**55.5**	**81.6**	**102.7**	**7,295**	**-**	**-**	**-**	**15,055,710.0**	**57,134,359**	**2.77**	**-**

LEGEND:
B.B. = BIG BEND — **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE — **ST = STEAM TURBINE**

(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) AC rating
(4) In Simple Cycle Mode

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 25 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	260	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	230	1.7	-	1.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,480	322.2	-	322.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,710	27.2	-	27.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,200	26.6	-	26.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,400	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,450	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,470	26.5	-	26.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,760	25.1	-	25.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	9,070	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	13,730	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,420	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	13,580	31.5	-	31.5	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**125,760**	**26.8**	**-**	**26.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**33,570**	**13.7**	**79.5**	**49.9**	**12,498**	**GAS**	**408,130**	**1,028,006**	**419,560.0**	**1,585,730**	**4.72**	**3.89**
19. B.B.#3 (GAS)	345	56,220	22.6	-	-	-	GAS	636,290	1,027,990	654,100.0	2,472,212	4.40	3.89
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**56,220**	**22.6**	**83.2**	**59.7**	**11,635**		**-**	**-**	**654,100.0**	**2,472,212**	**4.40**	**-**
22. B.B.#4 (GAS)	155	6,670	6.0	-	-	-	GAS	78,910	1,028,007	81,120.0	306,593	4.60	3.89
23. B.B.#4 (COAL)	422	126,580	41.7	-	-	-	COAL	68,500	22,499,708	1,541,230.0	5,461,415	4.31	79.73
24. BIG BEND #4 TOTAL	**422**	**133,250**	**43.9**	**89.8**	**47.6**	**12,175**		**-**	**-**	**1,622,350.0**	**5,768,008**	**4.33**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	40,070	1,027,951	41,190.0	155,686	-	3.89
26. B.B.C.T.#4 TOTAL	**56**	**3,420**	**8.5**	**98.3**	**81.4**	**11,918**	**GAS**	**39,650**	**1,027,995**	**40,760.0**	**154,054**	**4.50**	**3.89**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,163**	**226,460**	**27.0**	**85.2**	**50.8**	**12,085**	**-**	**-**	**-**	**2,736,770.0**	**10,135,690**	**4.48**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	67,360	48.7	-	91.8	8,810	GAS	577,250	1,028,012	593,420.0	2,242,821	3.33	3.89
32. POLK #1 TOTAL	**220**	**67,360**	**42.5**	**93.4**	**91.8**	**8,810**	**-**	**-**	**-**	**593,420.0**	**2,242,821**	**3.33**	**-**
33. POLK #2 ST DUCT FIRING	120	27,110	31.4	-	77.1	8,274	GAS	218,210	1,028,001	224,320.0	847,823	3.13	3.89
34. POLK #2 ST W/O DUCT FIRING	341	557,129	-	-	-	-		3,736,534	1,028,023	3,841,244.3	14,517,758	2.61	3.89
35. POLK #2 ST TOTAL	**461**	**584,239**	**176.0**	**-**	**126.5**	**6,959**	**GAS**	**-**	**-**	**4,065,564.3**	**15,365,581**	**2.63**	**-**
36. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
37. POLK #2 CT (OIL)	159	1,286	1.1	-	6.3	10,998	LGT OIL	2,412	5,863,557	14,142.9	196,853	15.31	81.61
38. POLK #2 TOTAL (4)	**150**	**1,286**	**1.2**	**-**	**6.3**	**10,998**	**-**	**-**	**-**	**14,142.9**	**196,853**	**15.31**	**-**
39. POLK #3 CT (GAS)	150	1,420	1.3	-	86.1	11,183	GAS	15,450	1,027,832	15,880.0	60,029	4.23	3.89
40. POLK #3 CT (OIL)	159	1,286	1.1	-	94.4	10,998	LGT OIL	2,412	5,863,557	14,142.9	196,853	15.31	81.61
41. POLK #3 TOTAL (4)	**150**	**2,706**	**2.5**	**-**	**89.8**	**11,095**	**-**	**-**	**-**	**30,022.9**	**256,882**	**9.49**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
44. POLK #2 CC TOTAL	**1,061**	**588,231**	**77.0**	**97.0**	**112.4**	**6,987**	**-**	**-**	**-**	**4,109,730.1**	**15,819,316**	**2.69**	**-**
45. POLK STATION TOTAL	**1,281**	**655,591**	**71.1**	**96.4**	**107.3**	**7,174**	**-**	**-**	**-**	**4,703,150.1**	**18,062,137**	**2.76**	**-**
46. BAYSIDE #1	720	430,040	83.0	97.3	85.2	7,295	GAS	3,051,570	1,028,002	3,137,020.0	11,856,431	2.76	3.89
47. BAYSIDE #2	954	486,520	70.8	97.4	72.8	7,419	GAS	3,511,300	1,027,995	3,609,600.0	13,642,644	2.80	3.89
48. BAYSIDE #3	56	4,320	10.7	98.6	87.7	11,725	GAS	49,280	1,027,800	50,650.0	191,470	4.43	3.89
49. BAYSIDE #4	56	3,950	9.8	98.6	89.3	11,737	GAS	45,100	1,027,938	46,360.0	175,229	4.44	3.89
50. BAYSIDE #5	56	6,910	17.1	98.6	90.7	11,564	GAS	77,730	1,028,046	79,910.0	302,009	4.37	3.89
51. BAYSIDE #6	56	5,940	14.7	98.6	89.9	11,635	GAS	67,220	1,028,117	69,110.0	261,174	4.40	3.89
52. BAYSIDE STATION TOTAL	**1,898**	**937,680**	**68.6**	**97.5**	**78.3**	**7,457**	**GAS**	**6,802,200**	**1,027,998**	**6,992,650.0**	**26,428,957**	**2.82**	**3.89**
53. SYSTEM TOTAL	**4,994**	**1,945,491**	**54.1**	**81.6**	**96.0**	**7,418**	**-**	**-**	**-**	**14,432,570.1**	**54,626,784**	**2.81**	**-**

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE
CT = COMBUSTION TURBINE
ST = STEAM TURBINE

(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) AC rating
(4) In Simple Cycle Mode

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 27 OF 42

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	220	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,600	322.6	-	322.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,550	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,050	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,040	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,300	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,340	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	7,140	25.7	-	25.7	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,970	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	14,260	25.7	-	25.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,090	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	13,520	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**125,370**	**25.8**	**-**	**25.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**52,810**	**20.9**	**79.5**	**52.1**	**12,354**	**GAS**	**634,640**	**1,028,000**	**652,410.0**	**2,455,183**	**4.65**	**3.87**
19. B.B.#3 (GAS)	345	52,530	20.5	-	-	-	GAS	580,580	1,028,006	596,840.0	2,246,045	4.28	3.87
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**52,530**	**20.5**	**59.0**	**66.2**	**11,362**		**-**	**-**	**596,840.0**	**2,246,045**	**4.28**	**-**
22. B.B.#4 (GAS)	155	3,780	3.3	-	-	-	GAS	45,150	1,028,128	46,420.0	174,668	4.62	3.87
23. B.B.#4 (COAL)	422	71,810	22.9	-	-	-	COAL	39,200	22,498,214	881,930.0	3,123,824	4.35	79.69
24. BIG BEND #4 TOTAL	**422**	**75,590**	**24.1**	**89.8**	**46.3**	**12,281**		**-**	**-**	**928,350.0**	**3,298,492**	**4.36**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	48,010	1,027,703	49,340.0	185,733	-	3.87
26. B.B.C.T.#4 TOTAL	**56**	**8,700**	**20.9**	**98.3**	**81.8**	**11,840**	**GAS**	**100,200**	**1,028,044**	**103,010.0**	**387,636**	**4.46**	**3.87**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,163**	**189,630**	**21.9**	**78.1**	**53.5**	**12,027**	**-**	**-**	**-**	**2,280,610.0**	**8,573,090**	**4.52**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	102,590	71.8	-	92.3	8,743	GAS	872,540	1,028,010	896,980.0	3,375,529	3.29	3.87
32. POLK #1 TOTAL	**220**	**102,590**	**62.7**	**93.4**	**92.3**	**8,743**	**-**	**-**	**-**	**896,980.0**	**3,375,529**	**3.29**	**-**
33. POLK #2 ST DUCT FIRING	120	15,630	17.5	-	65.1	8,276	GAS	125,830	1,027,974	129,350.0	486,789	3.11	3.87
34. POLK #2 ST W/O DUCT FIRING	341	279,661	-	-	-	-		1,870,654	1,028,045	1,923,115.7	7,236,856	2.59	3.87
35. POLK #2 ST TOTAL	**461**	**295,291**	**86.1**	**-**	**106.4**	**6,951**	**GAS**	**-**	**-**	**2,052,465.7**	**7,723,645**	**2.62**	**-**
36. POLK #2 CT (GAS)	150	43,590	39.1	-	86.7	11,111	GAS	471,130	1,027,997	484,320.0	1,822,625	4.18	3.87
37. POLK #2 CT (OIL)	159	1,200	1.0	-	5.8	11,000	LGT OIL	2,251	5,864,060	13,200.0	180,796	15.07	80.32
38. POLK #2 TOTAL (4)	**150**	**44,790**	**40.1**	**-**	**63.2**	**11,108**	**-**	**-**	**-**	**497,520.0**	**2,003,421**	**4.47**	**-**
39. POLK #3 CT (GAS)	150	43,550	39.0	-	86.7	11,112	GAS	470,770	1,027,975	483,940.0	1,821,232	4.18	3.87
40. POLK #3 CT (OIL)	159	1,329	1.1	-	94.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	200,234	15.07	80.32
41. POLK #3 TOTAL (4)	**150**	**44,879**	**40.2**	**-**	**86.9**	**11,109**	**-**	**-**	**-**	**498,554.3**	**2,021,466**	**4.50**	**-**

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 28 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL [4]	**150**	**35,700**	**32.0**	**-**	**88.8**	**11,040**	**GAS**	**383,410**	**1,027,986**	**394,140.0**	**1,483,269**	**4.15**	**3.87**
44. POLK #2 CC TOTAL	**1,061**	**420,660**	**53.3**	**53.2**	**87.6**	**8,184**	**-**	**-**	**-**	**3,442,680.0**	**13,231,801**	**3.15**	**-**
45. POLK STATION TOTAL	**1,281**	**523,250**	**54.9**	**60.1**	**88.8**	**8,294**	**-**	**-**	**-**	**4,339,660.0**	**16,607,330**	**3.17**	**-**
46. BAYSIDE #1	720	327,680	61.2	97.3	63.7	7,426	GAS	2,367,220	1,028,003	2,433,510.0	9,157,883	2.79	3.87
47. BAYSIDE #2	954	523,080	73.7	97.4	75.7	7,408	GAS	3,769,330	1,028,002	3,874,880.0	14,582,121	2.79	3.87
48. BAYSIDE #3	56	12,430	29.8	98.6	84.7	11,705	GAS	141,530	1,027,980	145,490.0	547,526	4.40	3.87
49. BAYSIDE #4	56	11,200	26.9	98.6	84.4	11,727	GAS	127,760	1,028,021	131,340.0	494,255	4.41	3.87
50. BAYSIDE #5	56	13,190	31.7	98.6	84.4	11,724	GAS	150,430	1,027,986	154,640.0	581,957	4.41	3.87
51. BAYSIDE #6	56	12,510	30.0	98.6	84.9	11,726	GAS	142,680	1,028,105	146,690.0	551,975	4.41	3.87
52. BAYSIDE STATION TOTAL	**1,898**	**900,090**	**63.7**	**97.5**	**71.2**	**7,651**	**GAS**	**6,698,950**	**1,028,004**	**6,886,550.0**	**25,915,717**	**2.88**	**3.87**
53. SYSTEM TOTAL	**4,994**	**1,738,340**	**46.8**	**70.7**	**84.0**	**7,770**	**-**	**-**	**-**	**13,506,820.0**	**51,096,137**	**2.94**	**-**

LEGEND:
B.B. = BIG BEND — **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE — **ST = STEAM TURBINE**

[1] **As burned fuel cost system total includes ignition**
[2] **Fuel burned (MM BTU) system total excludes ignition**
[3] **AC rating**
[4] **In Simple Cycle Mode**

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 29 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	270	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	180	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,970	274.6	-	274.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	10,130	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,500	19.6	-	19.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	12,030	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,420	19.2	-	19.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,720	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,040	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,700	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,780	21.9	-	21.9	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,070	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	10,210	23.7	-	23.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**99,020**	**21.1**	**-**	**21.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
19. B.B.#3 (GAS)	345	13,890	5.6	-	-	-	GAS	161,170	1,027,983	165,680.0	640,701	4.61	3.98
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**13,890**	**5.6**	**80.4**	**54.4**	**11,928**		**-**	**-**	**165,680.0**	**640,701**	**4.61**	**-**
22. B.B.#4 (GAS)	155	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
23. B.B.#4 (COAL)	422	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
24. BIG BEND #4 TOTAL	**422**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	2,920	1,027,397	3,000.0	11,608	-	3.98
26. B.B.C.T.#4 TOTAL	**56**	**380**	**0.9**	**98.3**	**39.9**	**15,553**	**GAS**	**5,750**	**1,027,826**	**5,910.0**	**22,858**	**6.02**	**3.98**
27. B.B.C.T.#5 TOTAL	**330**	**73,810**	**31.0**	**98.0**	**64.5**	**10,371**	**GAS**	**744,630**	**1,027,974**	**765,460.0**	**2,960,135**	**4.01**	**3.98**
28. B.B.C.T.#6 TOTAL	**330**	**54,680**	**23.0**	**98.0**	**69.0**	**10,131**	**GAS**	**538,900**	**1,028,001**	**553,990.0**	**2,142,294**	**3.92**	**3.98**
29. BIG BEND STATION TOTAL	**1,823**	**142,760**	**10.9**	**53.7**	**64.8**	**10,444**	**-**	**-**	**-**	**1,491,040.0**	**5,777,596**	**4.05**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	57,630	41.6	-	88.8	8,887	GAS	498,200	1,028,001	512,150.0	1,980,499	3.44	3.98
32. POLK #1 TOTAL	**220**	**57,630**	**36.3**	**87.2**	**88.8**	**8,887**	**-**	**-**	**-**	**512,150.0**	**1,980,499**	**3.44**	**-**
33. POLK #2 ST DUCT FIRING	120	24,650	28.5	-	74.2	8,273	GAS	198,370	1,027,978	203,920.0	788,582	3.20	3.98
34. POLK #2 ST W/O DUCT FIRING	341	594,930	-	-	-	-		3,992,494	1,028,017	4,104,350.0	15,871,402	2.67	3.98
35. POLK #2 ST TOTAL	**461**	**619,580**	**186.4**	**-**	**136.3**	**6,954**	**GAS**	**-**	**-**	**4,308,270.0**	**16,659,984**	**2.69**	**-**
36. POLK #2 CT (GAS)	150	750	0.7	-	100.0	10,800	GAS	7,880	1,027,919	8,100.0	31,326	4.18	3.98
37. POLK #2 CT (OIL)	159	1,114	1.0	-	5.4	11,003	LGT OIL	2,091	5,861,836	12,257.1	165,976	14.90	79.38
38. POLK #2 TOTAL (4)	**150**	**1,864**	**1.7**	**-**	**8.7**	**10,921**	**-**	**-**	**-**	**20,357.1**	**197,302**	**10.58**	**-**
39. POLK #3 CT (GAS)	150	450	0.4	-	100.0	10,889	GAS	4,770	1,027,254	4,900.0	18,962	4.21	3.98
40. POLK #3 CT (OIL)	159	986	0.9	-	94.4	10,997	LGT OIL	1,849	5,864,197	10,842.9	146,767	14.89	79.38
41. POLK #3 TOTAL (4)	**150**	**1,436**	**1.3**	**-**	**96.1**	**10,963**	**-**	**-**	**-**	**15,742.9**	**165,729**	**11.54**	**-**

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 30 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
44. POLK #2 CC TOTAL	**1,061**	**622,880**	**81.4**	**97.0**	**120.7**	**6,975**	**-**	**-**	**-**	**4,344,370.0**	**17,023,015**	**2.73**	**-**
45. POLK STATION TOTAL	**1,281**	**680,510**	**73.7**	**95.3**	**113.3**	**7,137**	**-**	**-**	**-**	**4,856,520.0**	**19,003,514**	**2.79**	**-**
46. BAYSIDE #1	720	315,180	60.7	97.3	62.4	7,438	GAS	2,280,380	1,027,987	2,344,200.0	9,065,218	2.88	3.98
47. BAYSIDE #2	954	198,180	28.8	52.0	55.5	7,575	GAS	1,460,280	1,027,995	1,501,160.0	5,805,065	2.93	3.98
48. BAYSIDE #3	56	2,050	5.1	98.6	79.6	12,059	GAS	24,060	1,027,431	24,720.0	95,646	4.67	3.98
49. BAYSIDE #4	56	1,620	4.0	98.6	78.2	12,093	GAS	19,050	1,028,346	19,590.0	75,730	4.67	3.98
50. BAYSIDE #5	56	3,210	8.0	98.6	85.6	11,838	GAS	36,960	1,028,139	38,000.0	146,927	4.58	3.98
51. BAYSIDE #6	56	2,470	6.1	98.6	83.2	11,943	GAS	28,690	1,028,233	29,500.0	114,052	4.62	3.98
52. BAYSIDE STATION TOTAL	**1,898**	**522,710**	**38.2**	**74.7**	**59.9**	**7,570**	**GAS**	**3,849,420**	**1,027,991**	**3,957,170.0**	**15,302,638**	**2.93**	**3.98**
53. SYSTEM TOTAL	**5,654**	**1,445,000**	**35.4**	**64.0**	**98.7**	**7,131**	**-**	**-**	**-**	**10,304,730.0**	**40,083,748**	**2.77**	**-**

LEGEND:
B.B. = BIG BEND — CT = COMBUSTION TURBINE
CC = COMBINED CYCLE — ST = STEAM TURBINE

[1] As burned fuel cost system total includes ignition
[2] Fuel burned (MM BTU) system total excludes ignition
[3] AC rating
[4] In Simple Cycle Mode

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DOCKET NO. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 31 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	260	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	160	1.1	-	1.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,700	241.9	-	241.9	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	8,500	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	8,800	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	10,420	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	7,070	15.6	-	15.6	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	6,480	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,050	18.1	-	18.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	5,620	15.3	-	15.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	10,490	18.9	-	18.9	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	10,460	18.9	-	18.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,580	19.3	-	19.3	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	74.5	9,070	16.4	-	16.4	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.5	9,070	16.4	-	16.4	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**801.2**	**102,730**	**17.2**	-	**17.2**	-	**SOLAR**	-	-	-	-	-	-
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**350**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
19. B.B.#3 (GAS)	355	123,910	46.9	-	-	-	GAS	1,419,150	1,028,003	1,458,890.0	5,862,424	4.73	4.13
20. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**355**	**123,910**	**46.9**	**83.2**	**53.8**	**11,774**		-	-	**1,458,890.0**	**5,862,424**	**4.73**	-
22. B.B.#4 (GAS)	160	2,080	1.7	-	-	-	GAS	26,380	1,027,672	27,110.0	108,974	5.24	4.13
23. B.B.#4 (COAL)	432	39,460	12.3	-	-	-	COAL	22,900	22,495,633	515,150.0	1,825,597	4.63	79.72
24. BIG BEND #4 TOTAL	**432**	**41,540**	**12.9**	**46.3**	**36.1**	**13,054**		-	-	**542,260.0**	**1,934,571**	**4.66**	-
25. B.B. IGNITION	-	-	-	-	-	-	GAS	17,950	1,027,855	18,450.0	74,150	-	4.13
26. B.B.C.T.#4 TOTAL	**61**	**0**	**0.0**	**98.3**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
27. B.B.C.T.#5 TOTAL	**350**	**14,540**	**5.6**	**98.0**	**62.0**	**10,534**	**GAS**	**148,980**	**1,028,057**	**153,160.0**	**615,427**	**4.23**	**4.13**
28. B.B.C.T.#6 TOTAL	**350**	**6,730**	**2.6**	**98.0**	**68.7**	**10,223**	**GAS**	**66,930**	**1,027,940**	**68,800.0**	**276,484**	**4.11**	**4.13**
29. BIG BEND STATION TOTAL	**1,898**	**186,720**	**13.2**	**65.4**	**49.3**	**11,906**	-	-	-	**2,223,110.0**	**8,763,056**	**4.69**	-
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	10,620	7.4	-	86.4	8,986	GAS	92,840	1,027,897	95,430.0	383,516	3.61	4.13
32. POLK #1 TOTAL	**220**	**10,620**	**6.5**	**57.3**	**86.4**	**8,986**	-	-	-	**95,430.0**	**383,516**	**3.61**	-
33. POLK #2 ST DUCT FIRING	120	4,550	5.1	-	72.9	8,178	GAS	36,200	1,027,901	37,210.0	149,540	3.29	4.13
34. POLK #2 ST W/O DUCT FIRING	360	684,803	-	-	-	-		4,605,135	1,028,018	4,734,161.4	19,023,535	2.78	4.13
35. POLK #2 ST TOTAL	**480**	**689,353**	**193.0**	-	**183.2**	**6,922**	**GAS**	-	-	**4,771,371.4**	**19,173,075**	**2.78**	-
36. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
37. POLK #2 CT (OIL)	187	1,329	1.0	-	5.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	195,299	14.70	78.34
38. POLK #2 TOTAL (4)	**180**	**1,329**	**1.0**	-	**5.4**	**10,996**	-	-	-	**14,614.3**	**195,299**	**14.70**	-
39. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
40. POLK #3 CT (OIL)	187	1,329	1.0	-	80.2	10,996	LGT OIL	2,493	5,862,134	14,614.3	195,298	14.70	78.34
41. POLK #3 TOTAL (4)	**180**	**1,329**	**1.0**	-	**80.2**	**10,996**	-	-	-	**14,614.3**	**195,298**	**14.70**	-

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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2021

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
44. POLK #2 CC TOTAL	**1,200**	**692,011**	**77.5**	**97.0**	**157.0**	**6,937**	**-**	**-**	**-**	**4,800,600.0**	**19,563,672**	**2.83**	**-**
45. POLK STATION TOTAL	**1,420**	**702,631**	**66.5**	**90.8**	**152.4**	**6,968**	**-**	**-**	**-**	**4,896,030.0**	**19,947,188**	**2.84**	**-**
46. BAYSIDE #1	792	292,400	49.6	97.3	51.6	7,390	GAS	2,101,920	1,028,008	2,160,790.0	8,682,904	2.97	4.13
47. BAYSIDE #2	1,047	257,040	33.0	97.4	34.1	7,833	GAS	1,958,690	1,027,993	2,013,520.0	8,091,231	3.15	4.13
48. BAYSIDE #3	61	70	0.2	98.6	57.4	13,857	GAS	950	1,021,053	970.0	3,924	5.61	4.13
49. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
50. BAYSIDE #5	61	60	0.1	98.6	98.4	11,333	GAS	660	1,030,303	680.0	2,726	4.54	4.13
51. BAYSIDE #6	61	90	0.2	98.6	73.8	12,556	GAS	1,110	1,018,018	1,130.0	4,585	5.09	4.13
52. BAYSIDE STATION TOTAL	**2,083**	**549,660**	**35.5**	**94.6**	**41.6**	**7,599**	**GAS**	**4,063,330**	**1,027,997**	**4,177,090.0**	**16,785,370**	**3.05**	**4.13**
53. SYSTEM TOTAL	**6,202**	**1,541,741**	**33.4**	**72.6**	**76.7**	**7,327**	**-**	**-**	**-**	**11,296,230.0**	**45,495,614**	**2.95**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **ST = STEAM TURBINE**

[1] As burned fuel cost system total includes ignition
[2] Fuel burned (MM BTU) system total excludes ignition
[3] AC rating
[4] In Simple Cycle Mode

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SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH JUNE 2021

		Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
	HEAVY OIL						
1.	PURCHASES:						
2.	UNITS (BBL)	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0
5.	BURNED:						
6.	UNITS (BBL)	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0
9.	ENDING INVENTORY:						
10.	UNITS (BBL)	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0
	LIGHT OIL						
14.	PURCHASES:						
15.	UNITS (BBL)	4,985	0	4,985	3,699	4,985	4,824
16.	UNIT COST ($/BBL)	63.73	0.00	65.07	65.16	65.55	66.03
17.	AMOUNT ($)	317,672	0	324,370	241,017	326,762	318,537
18.	BURNED:						
19.	UNITS (BBL)	4,986	0	4,986	3,698	4,986	4,824
20.	UNIT COST ($/BBL)	97.86	0.00	94.46	92.17	89.38	87.05
21.	AMOUNT ($)	487,933	0	470,965	340,852	445,648	419,916
22.	ENDING INVENTORY:						
23.	UNITS (BBL)	43,068	43,068	43,068	43,068	43,068	43,068
24.	UNIT COST ($/BBL)	97.88	97.88	94.47	92.16	89.40	87.04
25.	AMOUNT ($)	4,215,395	4,215,395	4,068,801	3,968,966	3,850,080	3,748,701
26.	DAYS SUPPLY: NORMAL	302,643	302,645	277,711	277,711	277,317	278,900
27.	DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
	COAL						
28.	PURCHASES:						
29.	UNITS (TONS)	30,000	30,000	30,000	30,000	30,000	42,857
30.	UNIT COST ($/TON)	71.94	71.94	71.94	71.94	71.94	71.94
31.	AMOUNT ($)	2,158,194	2,158,194	2,158,194	2,158,194	2,158,194	3,083,135
32.	BURNED:						
33.	UNITS (TONS)	61,050	55,390	30,780	40,910	77,080	72,580
34.	UNIT COST ($/TON)	71.87	74.67	75.25	77.44	77.47	79.00
35.	AMOUNT ($)	4,387,675	4,136,102	2,316,287	3,167,903	5,971,387	5,734,099
36.	ENDING INVENTORY:						
37.	UNITS (TONS)	176,794	151,404	150,624	139,714	92,634	62,911
38.	UNIT COST ($/TON)	67.84	69.04	69.74	70.23	70.42	69.41
39.	AMOUNT ($)	11,993,245	10,452,488	10,503,957	9,811,913	6,523,509	4,366,696
40.	DAYS SUPPLY:	108	106	93	67	39	27
	NATURAL GAS						
41.	PURCHASES:						
42.	UNITS (MCF)	8,403,735	8,272,150	9,654,975	9,848,783	11,287,592	12,398,004
43.	UNIT COST ($/MCF)	4.49	4.32	4.15	3.86	3.83	3.86
44.	AMOUNT ($)	37,705,734	35,716,395	40,093,689	38,044,373	43,248,757	47,888,000
45.	BURNED:						
46.	UNITS (MCF)	8,403,735	8,272,150	9,654,975	9,848,783	11,190,315	12,398,004
47.	UNIT COST ($/MCF)	4.48	4.32	4.16	3.87	3.84	3.86
48.	AMOUNT ($)	37,627,734	35,731,995	40,133,289	38,131,973	42,991,357	47,877,600
49.	ENDING INVENTORY:						
50.	UNITS (MCF)	291,829	291,829	291,829	291,829	389,105	389,105
51.	UNIT COST ($/MCF)	3.32	3.27	3.14	2.84	2.79	2.81
52.	AMOUNT ($)	970,200	954,600	915,000	827,400	1,084,800	1,095,200
53.	DAYS SUPPLY:	1	1	1	1	1	1
	NUCLEAR						
54.	BURNED:						
55.	UNITS (MMBTU)	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0
	OTHER						
58.	PURCHASES:						
59.	UNITS (MMBTU)	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0
62.	BURNED:						
63.	UNITS (MMBTU)	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0
66.	ENDING INVENTORY:						
67.	UNITS (MMBTU)	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-IGNITION AND ANALYSIS (2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENT (3) GAS-IGNITION

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

		Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	0	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0	0
5.	BURNED:							
6.	UNITS (BBL)	0	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0	0
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	0	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	4,985	4,985	4,824	4,744	3,940	4,985	51,941
16.	UNIT COST ($/BBL)	66.80	67.47	68.05	68.62	69.10	69.48	66.81
17.	AMOUNT ($)	332,982	336,331	328,259	325,520	272,238	346,378	3,470,066
18.	BURNED:							
19.	UNITS (BBL)	4,986	4,986	4,824	4,744	3,940	4,986	51,946
20.	UNIT COST ($/BBL)	84.93	83.11	81.61	80.32	79.38	78.34	86.27
21.	AMOUNT ($)	423,442	414,405	393,706	381,030	312,743	390,597	4,481,237
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	43,068	43,068	43,068	43,068	43,068	43,068	43,068
24.	UNIT COST ($/BBL)	84.94	83.13	81.61	80.32	79.38	78.35	78.35
25.	AMOUNT ($)	3,658,241	3,580,166	3,514,720	3,459,210	3,418,704	3,374,485	3,374,485
26.	DAYS SUPPLY: NORMAL	278,900	278,900	278,900	278,900	288,787	290,936	-
27.	DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	70,000	70,000	55,000	40,000	40,000	40,000	507,857
30.	UNIT COST ($/TON)	71.94	71.94	71.94	71.94	71.94	71.94	71.94
31.	AMOUNT ($)	5,035,787	5,035,787	3,956,690	2,877,593	2,877,593	2,877,593	36,535,148
32.	BURNED:							
33.	UNITS (TONS)	69,620	72,400	68,500	39,200	0	22,900	610,410
34.	UNIT COST ($/TON)	79.85	79.69	79.73	79.69	0.00	79.72	77.74
35.	AMOUNT ($)	5,559,374	5,769,559	5,461,415	3,123,824	0	1,825,597	47,453,222
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	63,291	60,891	47,391	48,191	88,191	105,291	105,291
38.	UNIT COST ($/TON)	68.21	66.94	64.10	63.47	67.31	67.85	67.85
39.	AMOUNT ($)	4,317,107	4,076,260	3,037,907	3,058,564	5,936,157	7,144,064	7,144,064
40.	DAYS SUPPLY:	28	31	40	71	98	70	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	12,946,375	13,064,755	12,552,694	12,301,864	9,907,227	10,476,895	131,115,049
43.	UNIT COST ($/MCF)	3.90	3.90	3.89	3.87	3.99	4.13	3.99
44.	AMOUNT ($)	50,439,440	50,952,795	48,767,663	47,599,283	39,507,205	43,317,820	523,281,154
45.	BURNED:							
46.	UNITS (MCF)	12,946,375	13,064,755	12,552,694	12,301,864	10,004,504	10,476,895	131,115,049
47.	UNIT COST ($/MCF)	3.89	3.90	3.89	3.87	3.98	4.13	3.99
48.	AMOUNT ($)	50,425,840	50,950,395	48,771,663	47,591,283	39,771,005	43,279,420	523,283,554
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	389,105	389,105	389,105	389,105	291,829	291,829	291,829
51.	UNIT COST ($/MCF)	2.85	2.86	2.85	2.87	2.92	3.05	3.05
52.	AMOUNT ($)	1,108,800	1,111,200	1,107,200	1,115,200	851,400	889,800	889,800
53.	DAYS SUPPLY:	1	1	1	1	1	1	-
	NUCLEAR							
54.	BURNED:							
55.	UNITS (MMBTU)	0	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58.	PURCHASES:							
59.	UNITS (MMBTU)	0	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0	0
62.	BURNED:							
63.	UNITS (MMBTU)	0	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0	0
66.	ENDING INVENTORY:							
67.	UNITS (MMBTU)	0	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-IGNITION AND ANALYSIS (2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENT (3) GAS-IGNITION

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TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH JUNE 2021

SCHEDULE E6

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) TOTAL COST $	(10) GAINS ON SALES
Jan-21	SEMINOLE	JURISD. SCH. - D	2,980.0	0.0	2,980.0	2.580	2.776	76,890.00	82,717.00	5,827.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,980.0**	**0.0**	**2,980.0**	**2.580**	**2.776**	**76,890.00**	**82,717.00**	**5,827.00**
Feb-21	SEMINOLE	JURISD. SCH. - D	2,690.0	0.0	2,690.0	2.722	2.928	73,210.00	78,758.00	5,548.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,690.0**	**0.0**	**2,690.0**	**2.722**	**2.928**	**73,210.00**	**78,758.00**	**5,548.00**
Mar-21	SEMINOLE	JURISD. SCH. - D	2,870.0	0.0	2,870.0	2.900	3.120	83,230.00	89,538.00	6,308.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,870.0**	**0.0**	**2,870.0**	**2.900**	**3.120**	**83,230.00**	**89,538.00**	**6,308.00**
Apr-21	SEMINOLE	JURISD. SCH. - D	3,010.0	0.0	3,010.0	2.674	2.877	80,490.00	86,590.00	6,100.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**3,010.0**	**0.0**	**3,010.0**	**2.674**	**2.877**	**80,490.00**	**86,590.00**	**6,100.00**
May-21	SEMINOLE	JURISD. SCH. - D	2,920.0	0.0	2,920.0	3.042	3.273	88,840.00	95,573.00	6,733.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,920.0**	**0.0**	**2,920.0**	**3.042**	**3.273**	**88,840.00**	**95,573.00**	**6,733.00**
Jun-21	SEMINOLE	JURISD. SCH. - D	2,920.0	0.0	2,920.0	3.205	3.448	93,590.00	100,683.00	7,093.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,920.0**	**0.0**	**2,920.0**	**3.205**	**3.448**	**93,590.00**	**100,683.00**	**7,093.00**

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TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

SCHEDULE E6

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) TOTAL COST $	(10) GAINS ON SALES
Jul-21	SEMINOLE	JURISD. SCH. - D	2,960.0	0.0	2,960.0	2.784	2.995	82,410.00	88,656.00	6,246.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,960.0**	**0.0**	**2,960.0**	**2.784**	**2.995**	**82,410.00**	**88,656.00**	**6,246.00**
Aug-21	SEMINOLE	JURISD. SCH. - D	3,000.0	0.0	3,000.0	2.765	2.975	82,960.00	89,247.00	6,287.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**3,000.0**	**0.0**	**3,000.0**	**2.765**	**2.975**	**82,960.00**	**89,247.00**	**6,287.00**
Sep-21	SEMINOLE	JURISD. SCH. - D	2,870.0	0.0	2,870.0	3.056	3.288	87,710.00	94,357.00	6,647.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,870.0**	**0.0**	**2,870.0**	**3.056**	**3.288**	**87,710.00**	**94,357.00**	**6,647.00**
Oct-21	SEMINOLE	JURISD. SCH. - D	2,960.0	0.0	2,960.0	2.531	2.723	74,910.00	80,587.00	5,677.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,960.0**	**0.0**	**2,960.0**	**2.531**	**2.723**	**74,910.00**	**80,587.00**	**5,677.00**
Nov-21	SEMINOLE	JURISD. SCH. - D	2,830.0	0.0	2,830.0	2.632	2.831	74,480.00	80,125.00	5,645.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,830.0**	**0.0**	**2,830.0**	**2.632**	**2.831**	**74,480.00**	**80,125.00**	**5,645.00**
Dec-21	SEMINOLE	JURISD. SCH. - D	3,030.0	0.0	3,030.0	2.481	2.669	75,160.00	80,856.00	5,696.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**3,030.0**	**0.0**	**3,030.0**	**2.481**	**2.669**	**75,160.00**	**80,856.00**	**5,696.00**
TOTAL										
Jan-21	SEMINOLE	JURISD. SCH. - D	35,040.0	0.0	35,040.0	2.779	2.990	973,880.00	1,047,687.00	73,807.00
THRU	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
Dec-21	**TOTAL**		**35,040.0**	**0.0**	**35,040.0**	**2.779**	**2.990**	**973,880.00**	**1,047,687.00**	**73,807.00**

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TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		
		TYPE	TOTAL	FOR	FOR	MWH	(A)	(B)	TOTAL $
	PURCHASED	&	MWH	OTHER	INTERRUP-	FOR	FUEL	TOTAL	FOR FUEL
MONTH	FROM	SCHEDULE	PURCHASED	UTILITIES	TIBLE	FIRM	COST	COST	ADJUSTMENT
Jan-21	VARIOUS	FIRM	640.0	0.0	0.0	640.0	4.401	4.401	28,164.33
	TOTAL		640.0	0.0	0.0	640.0	4.401	4.401	28,164.33
Feb-21	VARIOUS	FIRM	1,754.0	0.0	0.0	1,754.0	4.338	4.338	76,088.66
	TOTAL		1,754.0	0.0	0.0	1,754.0	4.338	4.338	76,088.66
Mar-21	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Apr-21	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
May-21	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Jun-21	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Jul-21	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Aug-21	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Sep-21	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Oct-21	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Nov-21	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Dec-21	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL Jan-21	VARIOUS	FIRM	2,394.0	0.0	0.0	2,394.0	4.355	4.355	104,252.99
THRU Dec-21	TOTAL		2,394.0	0.0	0.0	2,394.0	4.355	4.355	104,252.99

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		TOTAL $
		TYPE	TOTAL	FOR	FOR	MWH	(A)	(B)	FOR FUEL
	PURCHASED	&	MWH	OTHER	INTERRUP-	FOR	FUEL	TOTAL	ADJUST-
MONTH	FROM	SCHEDULE	PURCHASED	UTILITIES	TIBLE	FIRM	COST	COST	MENT
Jan-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,000.0	0.0	0.0	9,000.0	2.412	2.412	217,090.00
	TOTAL		9,000.0	0.0	0.0	9,000.0	2.412	2.412	217,090.00
Feb-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,000.0	0.0	0.0	9,000.0	2.811	2.811	252,980.00
	TOTAL		9,000.0	0.0	0.0	9,000.0	2.811	2.811	252,980.00
Mar-21	VARIOUS	CO-GEN.							
		AS AVAIL.	8,750.0	0.0	0.0	8,750.0	2.253	2.253	197,130.00
	TOTAL		8,750.0	0.0	0.0	8,750.0	2.253	2.253	197,130.00
Apr-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,360.0	0.0	0.0	9,360.0	2.447	2.447	229,010.00
	TOTAL		9,360.0	0.0	0.0	9,360.0	2.447	2.447	229,010.00
May-21	VARIOUS	CO-GEN.							
		AS AVAIL.	8,790.0	0.0	0.0	8,790.0	2.644	2.644	232,390.00
	TOTAL		8,790.0	0.0	0.0	8,790.0	2.644	2.644	232,390.00
Jun-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,070.0	0.0	0.0	9,070.0	2.733	2.733	247,890.00
	TOTAL		9,070.0	0.0	0.0	9,070.0	2.733	2.733	247,890.00
Jul-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,030.0	0.0	0.0	9,030.0	2.785	2.785	251,500.00
	TOTAL		9,030.0	0.0	0.0	9,030.0	2.785	2.785	251,500.00
Aug-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,120.0	0.0	0.0	9,120.0	2.734	2.734	249,360.00
	TOTAL		9,120.0	0.0	0.0	9,120.0	2.734	2.734	249,360.00
Sep-21	VARIOUS	CO-GEN.							
		AS AVAIL.	8,930.0	0.0	0.0	8,930.0	2.781	2.781	248,330.00
	TOTAL		8,930.0	0.0	0.0	8,930.0	2.781	2.781	248,330.00
Oct-21	VARIOUS	CO-GEN.							
		AS AVAIL.	8,970.0	0.0	0.0	8,970.0	3.240	3.240	290,630.00
	TOTAL		8,970.0	0.0	0.0	8,970.0	3.240	3.240	290,630.00
Nov-21	VARIOUS	CO-GEN.							
		AS AVAIL.	8,800.0	0.0	0.0	8,800.0	3.135	3.135	275,890.00
	TOTAL		8,800.0	0.0	0.0	8,800.0	3.135	3.135	275,890.00
Dec-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,200.0	0.0	0.0	9,200.0	2.623	2.623	241,290.00
	TOTAL		9,200.0	0.0	0.0	9,200.0	2.623	2.623	241,290.00
TOTAL	VARIOUS	CO-GEN.							
Jan-21		AS AVAIL.	108,020.0	0.0	0.0	108,020.0	2.716	2.716	2,933,490.00
THRU	TOTAL		108,020.0	0.0	0.0	108,020.0	2.716	2.716	2,933,490.00
Dec-21									

SCHEDULE E9

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
								COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) DOLLARS	FUEL SAVINGS (9B)-(8)
Jan-21	VARIOUS	SCH. - J	120,110.0	0.0	120,110.0	2.403	2,886,795.67	2.508	3,012,382.12	125,586.45
Feb-21	VARIOUS	SCH. - J	50,876.0	0.0	50,876.0	2.828	1,438,741.34	4.642	2,361,637.79	922,896.45
Mar-21	VARIOUS	SCH. - J	9,540.0	0.0	9,540.0	4.837	461,410.00	37.875	3,613,280.00	3,151,870.00
Apr-21	VARIOUS	SCH. - J	7,170.0	0.0	7,170.0	4.615	330,920.00	45.283	3,246,770.00	2,915,850.00
May-21	VARIOUS	SCH. - J	13,130.0	0.0	13,130.0	4.563	599,060.00	40.387	5,302,850.00	4,703,790.00
Jun-21	VARIOUS	SCH. - J	13,930.0	0.0	13,930.0	5.337	743,490.00	32.269	4,495,050.00	3,751,560.00
Jul-21	VARIOUS	SCH. - J	6,370.0	0.0	6,370.0	5.874	374,170.00	45.679	2,909,770.00	2,535,600.00
Aug-21	VARIOUS	SCH. - J	8,310.0	0.0	8,310.0	5.584	464,070.00	41.753	3,469,680.00	3,005,610.00
Sep-21	VARIOUS	SCH. - J	4,070.0	0.0	4,070.0	4.980	202,680.00	80.836	3,290,020.00	3,087,340.00
Oct-21	VARIOUS	SCH. - J	61,880.0	0.0	61,880.0	5.369	3,322,110.00	13.261	8,206,010.00	4,883,900.00
Nov-21	VARIOUS	SCH. - J	2,380.0	0.0	2,380.0	4.461	106,180.00	90.602	2,156,330.00	2,050,150.00
Dec-21	VARIOUS	SCH. - J	180.0	0.0	180.0	3.139	5,650.00	156.089	280,960.00	275,310.00
TOTAL	VARIOUS	SCH. - J	**297,946.0**	**0.0**	**297,946.0**	**3.670**	**10,935,277.01**	**14.212**	**42,344,739.91**	**31,409,462.90**

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SCHEDULE E10

TAMPA ELECTRIC COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH

	Current	Current	Projected	Difference	
	Jun 2020 - Aug 2020	Sep 2020 - Dec 2020	Jan 2021 - Dec 2021	$	%
Base Rate Revenue	67.76	67.76	67.30	(0.46)	-0.7%
Fuel Recovery Revenue	22.85	22.85	28.56	5.71	25.0%
Fuel Credit Recovery Revenue	(18.40)	0.00	0.00	0.00	0.0%
Conservation Revenue	2.32	2.32	1.66	(0.66)	-28.4%
Capacity Revenue	(0.12)	(0.12)	0.02	0.14	-116.7%
Environmental Revenue	2.44	2.44	2.69	0.25	10.2%
Storm Protection Plan Revenue	0.00	0.00	2.39	2.39	0.0%
Florida Gross Receipts Tax Revenue	1.97	2.44	2.63	0.19	7.8%
TOTAL REVENUE	**$78.82**	**$97.69**	**$105.25**	**$7.56**	**7.7%**

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REVISED: 09/14/2020

SCHEDULE H1

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
PERIOD: JANUARY THROUGH DECEMBER

	ACTUAL 2018	ACTUAL 2019	ACT/EST 2020	EST 2021	DIFFERENCE (%) 2019-2018	2020-2019	2021-2020
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL [1]	51,583	183,150	3,367,451	4,481,237	255.1%	1738.6%	33.1%
3 COAL	125,828,296	45,241,314	31,036,456	47,453,222	-64.0%	-31.4%	52.9%
4 NATURAL GAS	505,830,903	480,359,200	390,212,873	523,283,554	-5.0%	-18.8%	34.1%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**631,710,782**	**525,783,664**	**424,616,780**	**575,218,013**	**-16.8%**	**-19.2%**	**35.5%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL [1]	173	582	15,631	27,693	236.4%	2585.7%	77.2%
10 COAL	3,533,451	1,194,254	739,232	1,119,680	-66.2%	-38.1%	51.5%
11 NATURAL GAS	16,096,514	17,513,363	16,729,044	17,444,726	8.8%	-4.5%	4.3%
12 NUCLEAR	118,322	756,215	1,239,637	1,585,270	539.1%	63.9%	27.9%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	**19,748,460**	**19,464,414**	**18,723,544**	**20,177,369**	**-1.4%**	**-3.8%**	**7.8%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) [1]	405	1,436	29,665	51,946	254.6%	1965.8%	75.1%
17 COAL (TON)	1,626,026	570,012	396,204	610,410	-64.9%	-30.5%	54.1%
18 NATURAL GAS (MCF)	121,581,188	137,873,625	124,758,371	131,115,049	13.4%	-9.5%	5.1%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
22 LIGHT OIL [1]	1,349	8,362	173,875	304,543	519.9%	1979.3%	75.2%
23 COAL	38,881,879	13,177,799	8,959,418	13,733,780	-66.1%	-32.0%	53.3%
24 NATURAL GAS	124,229,756	140,983,651	127,781,699	134,413,197	13.5%	-9.4%	5.2%
25 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26 OTHER	0	0	0	0	0.0%	0.0%	0.0%
27 TOTAL (MMBTU)	**163,112,984**	**154,169,812**	**136,914,992**	**148,451,520**	**-5.5%**	**-11.2%**	**8.4%**
GENERATION MIX (% MWH)							
28 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
29 LIGHT OIL [1]	0.00	0.00	0.08	0.14	0.0%	0.0%	75.0%
30 COAL	17.89	6.13	3.95	5.54	-65.7%	-35.6%	40.3%
31 NATURAL GAS	81.51	89.98	89.35	86.46	10.4%	-0.7%	-3.2%
32 NUCLEAR	0.60	3.89	6.62	7.86	548.3%	70.2%	18.7%
33 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
34 TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**0.0%**	**0.0%**	**0.0%**
FUEL COST PER UNIT							
35 HEAVY OIL ($/BBL) [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
36 LIGHT OIL ($/BBL) [1]	127.37	127.54	113.52	86.27	0.1%	-11.0%	-24.0%
37 COAL ($/TON)	77.38	79.37	78.33	77.74	2.6%	-1.3%	-0.8%
38 NATURAL GAS ($/MCF)	4.16	3.48	3.13	3.99	-16.3%	-10.1%	27.5%
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)							
41 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
42 LIGHT OIL [1]	38.24	21.90	19.37	14.71	-42.7%	-11.6%	-24.1%
43 COAL	3.24	3.43	3.46	3.46	5.9%	0.9%	0.0%
44 NATURAL GAS	4.07	3.41	3.05	3.89	-16.2%	-10.6%	27.5%
45 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL ($/MMBTU)	**3.87**	**3.41**	**3.10**	**3.87**	**-11.9%**	**-9.1%**	**24.8%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL [1]	7,798	14,368	11,124	10,997	84.3%	-22.6%	-1.1%
50 COAL	11,004	11,034	12,120	12,266	0.3%	9.8%	1.2%
51 NATURAL GAS	7,718	8,050	7,638	7,705	4.3%	-5.1%	0.9%
52 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53 OTHER	0	0	0	0	0.0%	0.0%	0.0%
54 TOTAL (BTU/KWH)	**8,260**	**7,921**	**7,312**	**7,357**	**-4.1%**	**-7.7%**	**0.6%**
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
56 LIGHT OIL [1]	29.82	31.47	21.54	16.18	5.5%	-31.6%	-24.9%
57 COAL	3.56	3.79	4.20	4.24	6.5%	10.8%	1.0%
58 NATURAL GAS	3.14	2.74	2.33	3.00	-12.7%	-15.0%	28.8%
59 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61 TOTAL (cents/KWH)	**3.20**	**2.70**	**2.27**	**2.85**	**-15.6%**	**-15.9%**	**25.6%**

[1] DISTILLATE (BBLS, MWH & $) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 3

LEVELIZED AND TIERED FUEL RATE

JANUARY 2021 - DECEMBER 2021

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period January 2021 through December 2021

	Annual Units MWH	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues $	Tiered Fuel Rates Cents/kWh	Annual Fuel Revenues $
Residential Excluding TOU:					
TIER I (Up to 1,000) kWh	6,599,989	3.167	209,021,646	2.856	188,495,681
TIER II (Over 1,000) kWh	2,979,095	3.167	94,347,942	3.856	114,873,907
Total	9,579,084		303,369,588		303,369,588

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GENERATING PERFORMANCE INCENTIVE FACTOR

INDEX

EXHIBIT TO THE TESTIMONY OF

JEREMY B. CAIN

DOCKET NO. 20200001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2019 – DECEMBER 2019

TRUE-UP

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2019 - DECEMBER 2019
TRUE-UP
TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ACTUAL
JANUARY 2019 - DECEMBER 2019

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	10,838.7	5,419.3
+9	9,754.8	4,877.4
+8	8,671.0	4,335.5
+7	7,587.1	3,793.5
+6	6,503.2	3,251.6
+5	5,419.3	2,709.7
+4	4,335.5	2,167.7
+3	3,251.6	1,625.8
+2	2,167.7	1,083.9
+1	1,083.9	541.9
0	0.0	0.0
-1	(1,256.1)	(541.9)
-2	(2,512.1)	(1,083.9)
-3	(3,768.2)	(1,625.8)
-4	(5,024.3)	(2,167.7)
-5	(6,280.3)	(2,709.7)
-6	(7,536.4)	(3,251.6)
-7	(8,792.4)	(3,793.5)
-8	(10,048.5)	(4,335.5)
-9	(11,304.6)	(4,877.4)
-10	(12,560.6)	(5,419.3)

GPI POINTS 5.274

REWARD DOLLARS $2,858,056

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS - ACTUAL
JANUARY 2019 - DECEMBER 2019

Line 1	Beginning of period balance of common equity: End of month common equity:		$	2,867,405,914	
Line 2	Month of January	2019	$	2,882,004,481	
Line 3	Month of February	2019	$	2,909,743,602	
Line 4	Month of March	2019	$	2,924,640,926	
Line 5	Month of April	2019	$	2,946,588,417	
Line 6	Month of May	2019	$	3,011,756,553	
Line 7	Month of June	2019	$	3,047,198,358	
Line 8	Month of July	2019	$	3,085,572,885	
Line 9	Month of August	2019	$	3,033,558,076	
Line 10	Month of September	2019	$	3,069,893,560	
Line 11	Month of October	2019	$	3,104,286,978	
Line 12	Month of November	2019	$	3,155,976,279	
Line 13	Month of December	2019	$	3,164,685,873	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	3,015,639,377	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			75.30%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	10,012,482	
Line 18	Jurisdictional Sales			19,783,566	MWH
Line 19	Total Sales			19,783,566	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			100.00%	
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)		$	10,012,482	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-Point level from Sheet No. 3.515)		$	5,419,348	
Line 23	**Maximum Allowed GPIF Reward (At 10 GPIF-Point Level; the lesser of line 21 and line 22)**		**$**	**5,419,348**	

TAMPA ELECTRIC COMPANY
CALCULATION OF SYSTEM GPIF POINTS - ACTUAL
JANUARY 2019 - DECEMBER 2019

PLANT / UNIT	12 MONTH ADJ. ACTUAL PERFORMANCE		WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
POLK 1	77.0%	EAF	5.07%	-10.000	-0.507
POLK 2	90.6%	EAF	1.90%	-1.742	-0.033
BAYSIDE 1	89.1%	EAF	1.11%	-10.000	-0.111
BAYSIDE 2	89.0%	EAF	3.12%	10.000	0.312
POLK 1	8,880	ANOHR	10.57%	10.000	1.057
POLK 2	6,469	ANOHR	36.89%	10.000	3.689
BAYSIDE 1	7,344	ANOHR	14.00%	0.000	0.000
BAYSIDE 2	7,438	ANOHR	27.35%	3.170	0.867
			100.00%		5.274

GPIF REWARD **$ 2,858,056**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF MAX. (%)	RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	EAF ADJUSTED ACTUAL (%)	EST. FUEL SAVINGS/ LOSS ($000)
POLK 1	5.07%	83.3	85.4	79.1	549.8	(342.2)	77.0%	(342.2)
POLK 2	1.90%	90.9	91.7	89.2	205.7	(1,759.2)	90.6%	(306.4)
BAYSIDE 1	1.11%	91.0	91.7	89.5	120.0	(60.0)	89.1%	(60.0)
BAYSIDE 2	3.12%	87.4	88.8	84.7	337.7	(773.7)	89.0%	337.7
GPIF SYSTEM	**11.19%**				**1,213.2**	**(2,935.1)**		

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR (Btu/kwh)	TARGET NOF (%)	ANOHR TARGET RANGE MIN.	ANOHR TARGET RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	ACTUAL ADJUSTED ANOHR	EST. FUEL SAVINGS/ LOSS ($000)
POLK 1	10.57%	10,124	86.4	9,187	11,061	1,145.8	(1,145.8)	8,880	1,145.8
POLK 2	36.89%	6,904	81.0	6,731	7,077	3,998.7	(3,998.7)	6,469	3,998.7
BAYSIDE 1	14.00%	7,400	80.6	7,284	7,516	1,517.1	(1,517.1)	7,344	0.0
BAYSIDE 2	27.35%	7,561	60.5	7,334	7,789	2,964.0	(2,964.0)	7,438	939.6
GPIF SYSTEM	**88.81%**					**9,625.5**	**(9,625.5)**		

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EXHIBIT NO._____ JBC-1)
TAMPA ELECTRIC COMPANY
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TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2019 - DECEMBER 2019

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF ADJUSTED ACTUAL (%)
POLK 1	78.9	-1.9	77.0
POLK 2	92.6	-2.0	90.6
BAYSIDE 1	85.1	4.0	89.1
BAYSIDE 2	85.5	3.5	89.0

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
POLK 1	8,960	-80	8,880
POLK 2	6,997	-528	6,469
BAYSIDE 1	7,402	-58	7,344
BAYSIDE 2	7,408	30	7,438

(1) Documentation of adjustments to Actual EAF on pages 7 - 10

(2) Documentation of adjustments to Actual ANOHR on pages 11 - 14

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
POLK UNIT NO. 1
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 5.07%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	83.3	78.9	77.0
POH	720.0	419.0	720.0
FOH + EFOH	599.1	620.3	597.9
MOH + EMOH	143.3	729.0	702.7
POF	8.2	4.8	8.2
EFOF	6.8	7.1	6.8
EMOF	1.6	8.3	8.0
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times \left(FOH + EFOH + MOH + EMOH\right) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 720}{8760 - 419} \times (620.3 + 729) = 1{,}300.6$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 8.2 - \frac{1300.6}{8{,}760.0} \times 100 = 77.0$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
POLK UNIT NO. 2
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 1.90%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	90.9	92.6	90.6
POH	576.0	391.4	576.0
FOH + EFOH	108.5	179.1	175.1
MOH + EMOH	113.5	76.0	74.3
POF	6.6	4.5	6.6
EFOF	1.2	2.0	2.0
EMOF	1.3	0.9	0.8
	-1.742	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 576}{8760 - 391.4} \times (179.1 + 76) = 249.5$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{249.5}{8,760.0} \times 100 = 90.6$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BAYSIDE UNIT NO. 1
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 1.11%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	91.0	85.1	89.1
POH	624.0	973.6	624.0
FOH + EFOH	83.9	259.4	271.0
MOH + EMOH	82.8	62.5	65.3
POF	7.1	11.1	7.1
EFOF	1.0	3.0	3.1
EMOF	0.9	0.7	0.7
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 624}{8760 - 973.6} \times (259.4 + 62.5) = 336.4$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 7.1 - \frac{336.4}{8{,}760.0} \times 100 = 89.1$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BAYSIDE UNIT NO. 2
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 3.12%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	87.4	85.5	89.0
POH	671.0	998.0	671.0
FOH + EFOH	204.3	132.1	137.7
MOH + EMOH	224.5	144.8	150.9
POF	7.7	11.4	7.7
EFOF	2.3	1.5	1.6
EMOF	2.6	1.7	1.7
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times \left(FOH + EFOH + MOH + EMOH\right) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 671}{8760 - 998} \times (132.1 + 144.8) = 288.6$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 7.7 - \frac{288.6}{8,760.0} \times 100 = 89.0$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 1
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 10.57%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,124	8,960
NET GENERATION (GWH)	458.2	622.5
OPERATING BTU (10^9)	3,747.9	5,577.4
NET OUTPUT FACTOR	86.4	59.0

10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-2.93) + 10377.49 = ANOHR

59 * (-2.93) + 10377.49 = 10,204

8,960 - 10,204 = -1244

10,124 + -1244 = 8,880 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 2
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 36.89%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	6,904	6,997
NET GENERATION (GWH)	7,509.5	6,399.5
OPERATING BTU (10^9)	51,036.1	44,776.0
NET OUTPUT FACTOR	81.0	71.2

10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-53.86) + 11266.21 = ANOHR

71.2 * (-53.86) + 11266.21 = 7,431

6,997 - 7,431 = -434

6,904 + -434 = 6,469 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 1
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 14.00%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	7,400	7,402
NET GENERATION (GWH)	4,520.1	3,192.8
OPERATING BTU (10^9)	32,958.7	23,632.0
NET OUTPUT FACTOR	80.6	60.2

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-2.85) + 7629.82 = ANOHR

60.2 * (-2.85) + 7629.82 = 7,458

7,402 - 7,458 = -56

7,400 + -56 = 7,344 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 2
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 27.35%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	7,561	7,408
NET GENERATION (GWH)	4,441.0	4,648.5
OPERATING BTU (10^9)	33,370.3	34,437.1
NET OUTPUT FACTOR	60.5	64.9

3.170 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-6.67) + 7964.98 = ANOHR

64.9 * (-6.67) + 7964.98 = 7,532

7,408 - 7,532 = -124

7,561 + -124 = 7,438 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

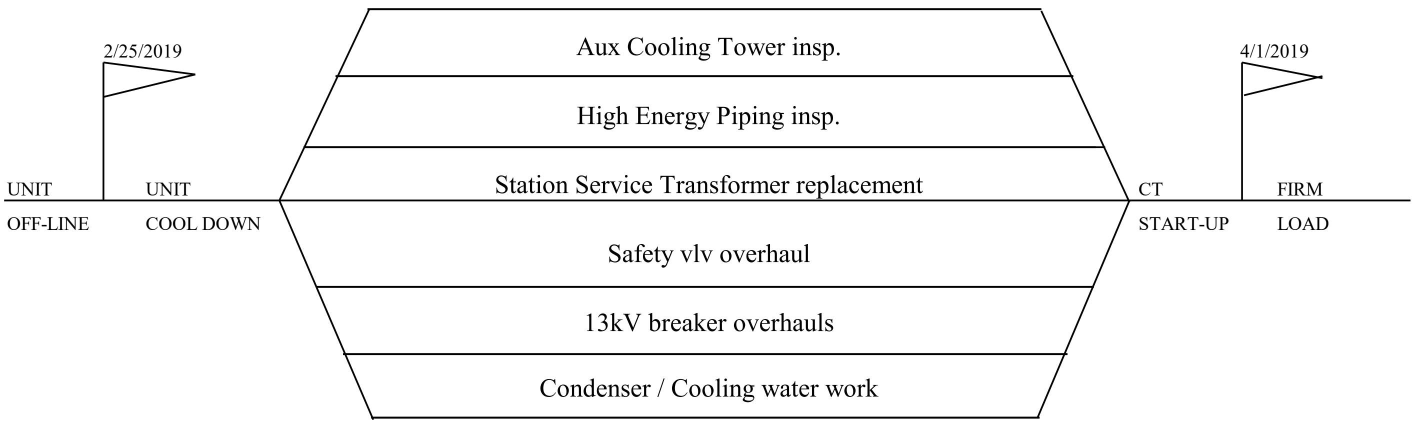
ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ACTUAL)
GPIF UNITS
JANUARY 2019 - DECEMBER 2019

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	POLK 1	Oct 09	-	Oct 26	Fuel System Cleanup
	POLK 2	Apr 09	-	Apr 22	LP Steam Vlv repairs, Hotwell inspection
		Nov 19	-	Nov 25	Fuel System Cleanup
+	BAYSIDE 1	Feb 25	-	Apr 01	Station Service Transformer replacement, Aux Cooling Tower insp., High Energy Piping insp., Safety vlv overhaul, 13kV breaker overhauls, Condenser / Cooling water work
		Oct 27	-	Nov 09	Fuel System Cleanup
	BAYSIDE 2	Jan 12	-	Feb 01	Fuel System Cleanup
		Dec 02		Dec 16	Fuel System Cleanup

\+ **CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2019 - DECEMBER 2019



TAMPA ELECTRIC COMPANY
BAYSIDE 1
PLANNED OUTAGE 2019
ACTUAL CPM

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TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2019 - DECEMBER 2019

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	549.8	85.4	+10	1,145.8	9,187
+9	494.8	85.2	+9	1,031.2	9,274
+8	439.8	85.0	+8	916.6	9,360
+7	384.9	84.8	+7	802.1	9,446
+6	329.9	84.6	+6	687.5	9,532
+5	274.9	84.4	+5	572.9	9,618
+4	219.9	84.1	+4	458.3	9,704
+3	164.9	83.9	+3	343.7	9,791
+2	110.0	83.7	+2	229.2	9,877
+1	55.0	83.5	+1	114.6	9,963
					10,049
0	0.0	83.3	0	0.0	10,124
					10,199
-1	(34.2)	82.9	-1	(114.6)	10,285
-2	(68.4)	82.5	-2	(229.2)	10,372
-3	(102.7)	82.0	-3	(343.7)	10,458
-4	(136.9)	81.6	-4	(458.3)	10,544
-5	(171.1)	81.2	-5	(572.9)	10,630
-6	(205.3)	80.8	-6	(687.5)	10,716
-7	(239.6)	80.4	-7	(802.1)	10,802
-8	(273.8)	79.9	-8	(916.6)	10,889
-9	(308.0)	79.5	-9	(1,031.2)	10,975
-10	(342.2)	79.1	-10	(1,145.8)	11,061

AHR POINTS 10.000

Adjusted ANOHR 8,880

EAF POINTS -10.000

Adjusted EAF 77.0

Weighting Factor = 5.07%

Weighting Factor = 10.57%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2019 - DECEMBER 2019

POLK 2

AHR POINTS 10.000

Adjusted ANOHR 6,469

EAF POINTS -1.742

Adjusted EAF 90.6

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	205.7	91.7	+10	3,998.7	6,731
+9	185.2	91.6	+9	3,598.8	6,741
+8	164.6	91.6	+8	3,198.9	6,750
+7	144.0	91.5	+7	2,799.1	6,760
+6	123.4	91.4	+6	2,399.2	6,770
+5	102.9	91.3	+5	1,999.3	6,780
+4	82.3	91.2	+4	1,599.5	6,790
+3	61.7	91.1	+3	1,199.6	6,799
+2	41.1	91.1	+2	799.7	6,809
+1	20.6	91.0	+1	399.9	6,819
					6,829
0	0.0	90.9	0	0.0	6,904
					6,979
-1	(175.9)	90.7	-1	(399.9)	6,988
-2	(351.8)	90.6	-2	(799.7)	6,998
-3	(527.8)	90.4	-3	(1,199.6)	7,008
-4	(703.7)	90.2	-4	(1,599.5)	7,018
-5	(879.6)	90.1	-5	(1,999.3)	7,028
-6	(1,055.5)	89.9	-6	(2,399.2)	7,037
-7	(1,231.5)	89.7	-7	(2,799.1)	7,047
-8	(1,407.4)	89.6	-8	(3,198.9)	7,057
-9	(1,583.3)	89.4	-9	(3,598.8)	7,067
-10	(1,759.2)	89.2	-10	(3,998.7)	7,077

Weighting Factor = 1.90%

Weighting Factor = 36.89%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2019 - DECEMBER 2019

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	120.0	91.7	+10	1,517.1	7,284
+9	108.0	91.6	+9	1,365.4	7,288
+8	96.0	91.6	+8	1,213.7	7,292
+7	84.0	91.5	+7	1,061.9	7,296
+6	72.0	91.4	+6	910.2	7,300
+5	60.0	91.3	+5	758.5	7,305
+4	48.0	91.3	+4	606.8	7,309
+3	36.0	91.2	+3	455.1	7,313
+2	24.0	91.1	+2	303.4	7,317
+1	12.0	91.0	+1	151.7	7,321
					7,325
0	0.0	91.0	0	0.0	7,400
					7,475
-1	(6.0)	90.8	-1	(151.7)	7,479
-2	(12.0)	90.7	-2	(303.4)	7,483
-3	(18.0)	90.5	-3	(455.1)	7,487
-4	(24.0)	90.4	-4	(606.8)	7,491
-5	(30.0)	90.2	-5	(758.5)	7,495
-6	(36.0)	90.1	-6	(910.2)	7,500
-7	(42.0)	89.9	-7	(1,061.9)	7,504
-8	(48.0)	89.8	-8	(1,213.7)	7,508
-9	(54.0)	89.6	-9	(1,365.4)	7,512
-10	(60.0)	89.5	-10	(1,517.1)	7,516

AHR POINTS 0.000

Adjusted ANOHR 7,344

EAF POINTS -10.000

Adjusted EAF 89.1

Weighting Factor = 1.11%

Weighting Factor = 14.00%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2019 - DECEMBER 2019

BAYSIDE 2

EAF POINTS 10.000 | **Adjusted EAF 89.0** | **AHR POINTS 3.170** | **Adjusted ANOHR 7,438**

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	337.7	88.8	+10	2,964.0	7,334
+9	303.9	88.7	+9	2,667.6	7,349
+8	270.1	88.5	+8	2,371.2	7,364
+7	236.4	88.4	+7	2,074.8	7,379
+6	202.6	88.3	+6	1,778.4	7,395
+5	168.8	88.1	+5	1,482.0	7,410
+4	135.1	88.0	+4	1,185.6	7,425
+3	101.3	87.9	+3	889.2	7,441
+2	67.5	87.7	+2	592.8	7,456
+1	33.8	87.6	+1	296.4	7,471
					7,486
0	0.0	87.4	0	0.0	7,561
					7,636
-1	(77.4)	87.2	-1	(296.4)	7,652
-2	(154.7)	86.9	-2	(592.8)	7,667
-3	(232.1)	86.6	-3	(889.2)	7,682
-4	(309.5)	86.4	-4	(1,185.6)	7,698
-5	(386.8)	86.1	-5	(1,482.0)	7,713
-6	(464.2)	85.8	-6	(1,778.4)	7,728
-7	(541.6)	85.5	-7	(2,074.8)	7,743
-8	(618.9)	85.3	-8	(2,371.2)	7,759
-9	(696.3)	85.0	-9	(2,667.6)	7,774
-10	(773.7)	84.7	-10	(2,964.0)	7,789

Weighting Factor = 3.12%

Weighting Factor = 27.35%

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 19 - DEC 19 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 19 - DEC 19 POF	EUOF	EUOR
POLK 1	5.1%	45.3%	8.2	8.5	9.2	4.8	15.4	16.2
POLK 2	1.9%	17.0%	6.6	2.5	2.7	4.5	2.9	3.0
BAYSIDE 1	1.1%	9.9%	7.1	1.9	2.0	11.1	3.7	4.1
BAYSIDE 2	3.1%	27.8%	7.7	4.9	5.3	11.4	3.2	3.6
GPIF SYSTEM	**11.2%**	**100.0%**	**7.7**	**5.8**	**6.3**	**7.2**	**8.7**	**9.2**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%				**86.5**			**84.1**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
7.7	**15.6**	**16.7**	**76.7**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 19 - DEC 19	ADJUSTED ACTUAL HEAT RATE JAN 19 - DEC 19
POLK 1	10.57%	11.9%	10,124	8,880
POLK 2	36.89%	41.5%	6,904	6,469
BAYSIDE 1	14.00%	15.8%	7,400	7,344
BAYSIDE 2	27.35%	30.8%	7,561	7,438
GPIF SYSTEM	**88.8%**	**100.0%**		
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			**7,568**	**7,192**

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION
JANUARY 2019 - DECEMBER 2019

Points are calculated according to the formula:

$$GPIP = \sum_{i=1}^{n} \left[a_i \left(EAP_i \right) + e_i \left(AHRP_i \right) \right]$$

Where:

$GPIP$ = Generating performance incentive points

a_i = Percentage of total system fuel cost reduction attributed to maximum reasonably attainable equivalent availability of unit i during the period

e_i = Percentage of total system fuel cost reduction attributed to minimum reasonably attainable average heat rate of unit i during the period

EAP_i = Equivalent availability points awarded/deducted for unit i

$AHRP_i$ = Average heat rate points awarded/deducted for unit i

Weighting factors and point values are listed on page 4.

GPIP =	5.07%	*	(PK 1 EAP)	+	1.90%	*	(PK 2 EAP)	+	1.11%	* (BAY 1 EAP)
+	3.12%	*	(BAY 2 EAP)	+	10.57%	*	(PK 1 AHRP)	+	36.89%	* (PK 2 AHRP)
+	14.00%	*	(BAY 1 AHRP)	+	27.35%	*	(BAY 2 AHRP)			

GPIP =	5.07%	*	-10.000	+	1.90%	*	-1.742	+	1.11%	*	-10.000
+	3.12%	*	10.000	+	10.57%	*	10.000	+	36.89%	*	10.000
+	14.00%	*	0.000	+	27.35%	*	3.170				

GPIP =	-0.507	+	-0.033	+	-0.111
+	0.312	+	1.057	+	3.689
+	0.000	+	0.867		

GPIP = <u>5.274</u> POINTS

REWARD/PENALTY dollar amounts of the Generating Performance Incentive Factor (GPIF) are determined directly from the table for the corresponding Generating Performance Points (GPIP) on page 2.

GPIF REWARD = $2,858,056

EXHIBIT TO THE TESTIMONY OF

JEREMY B. CAIN

DOCKET NO. 20200001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2019 - DECEMBER 2019

TRUE-UP

DOCUMENT NO. 2

ACTUAL UNIT PERFORMANCE DATA

TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1		JAN 19	FEB 19	MAR 19	APR 19	MAY 19	JUN 19	JUL 19	AUG 19	SEP 19	OCT 19	NOV 19	DEC 19	2019
1. Equivalent Availability Factor (%)	EAF	61.1	18.0	81.8	100.0	68.9	98.5	98.8	100.0	100.0	43.7	86.9	82.9	78.9
2. Period Hours	PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
3. Service Hours	SH	192.7	53.0	458.1	692.0	509.0	667.2	319.9	409.9	465.6	133.8	358.1	173.9	4,433.2
4. Reserve Shutdown Hours	RSH	322.9	0.0	179.0	28.0	3.4	42.0	415.5	334.1	254.4	191.2	279.3	443.1	2,492.9
5. Unavailable Hours	UH	213.9	539.6	106.9	0.0	231.6	10.8	8.6	0.0	0.0	419.0	82.6	127.0	1,740.0
6. Planned Outage Hours	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	419.0	0.0	0.0	419.0
7. Forced Outage Hours	FOH	19.6	539.6	0.0	0.0	41.5	8.7	0.0	0.0	0.0	0.0	0.0	0.0	609.4
8. Maintenance Outage Hours	MOH	208.8	0.0	106.9	0.0	190.1	2.1	8.6	0.0	0.0	0.0	82.6	127.0	726.1
9a. Partial Planned Outage Hours	PPOH	744.0	493.0	30.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,267.9
9b. Load Reduction Partial Planned (MW)	LRPP	20.0	5.0	65.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3
10a. Partial Forced Outage Hours	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	372.2	0.0	372.2
10b. Load Reduction Partial Forced (MW)	LRPF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	7.0
11a. Partial Maintenance Outage Hours	PMOH	0.0	0.0	46.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.7
11b. Load Reduction Partial Maintenance (MW)	LRPM	0.0	0.0	15.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.0
12. Net Summer Continuous Rating (MW)	NSC	235	235	235	235	235	235	235	235	235	235	235	235	235
13. Operating British Thermal Units (GBTU)	OPR BTU	247.0	62.5	551.9	884.0	657.3	872.8	386.1	475.2	515.6	181.6	493.7	249.7	5,577.4
14. Net Generation (MWH)	NETGEN	23,968.3	4,295.0	61,112.0	103,624.0	75,289.0	101,034.8	40,693.3	51,490.0	55,151.1	19,059.4	59,836.1	26,913.0	622,466.0
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	10,304.7	14,559.0	9,032.0	8,531.0	8,731.0	8,639.0	9,789.0	9,229.0	9,348.0	9,529.0	8,251.0	9,279.0	8,960.2
16. Net Output Factor (%)	NOF	50.8	32.9	55.1	64.5	62.9	64.4	54.1	53.5	50.4	60.6	71.1	63.9	59.0

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EXHIBIT NO. _____ (JBC-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20200001-EI
DOCUMENT NO. 2
PAGE 1 OF 4

ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 2		JAN 19	FEB 19	MAR 19	APR 19	MAY 19	JUN 19	JUL 19	AUG 19	SEP 19	OCT 19	NOV 19	DEC 19	2019
1. Equivalent Availability Factor (%)	EAF	98.7	95.3	99.5	64.2	99.4	80.4	97.0	99.5	99.3	99.9	71.7	93.0	92.6
2. Period Hours	PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
3. Service Hours	SH	742.3	643.0	741.8	396.0	744.0	643.1	730.9	740.3	715.1	743.4	569.2	713.4	8,122.5
4. Reserve Shutdown Hours	RSH	0.0	0.0	0.0	66.5	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	67.5
5. Unavailable Hours	UH	1.7	29.0	2.2	257.5	0.0	76.9	12.1	3.7	4.9	0.6	150.8	30.6	570.0
6. Planned Outage Hours	POH	0.0	0.0	0.0	245.0	0.0	0.0	0.0	0.0	0.0	0.0	120.7	25.7	391.4
7. Forced Outage Hours	FOH	1.7	29.0	2.2	10.1	0.0	76.9	2.5	0.1	0.3	0.6	16.6	0.2	140.2
8. Maintenance Outage Hours	MOH	0.0	0.0	0.0	2.4	0.0	0.0	9.6	3.6	4.7	0.0	13.5	4.7	38.5
9a. Partial Planned Outage Hours	PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9b. Load Reduction Partial Planned (MW)	LRPP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10a. Partial Forced Outage Hours	PFOH	5.0	8.4	5.8	0.0	18.3	237.6	7.6	0.0	0.0	1.7	51.0	0.4	335.8
10b. Load Reduction Partial Forced (MW)	LRPF	34.0	298.6	97.0	0.0	138.0	125.2	124.9	0.0	0.0	124.5	125.0	123.4	128.3
11a. Partial Maintenance Outage Hours	PMOH	32.3	0.0	0.0	0.0	0.0	0.0	29.7	0.0	0.0	0.0	135.7	81.1	278.8
11b. Load Reduction Partial Maintenance (MW)	LRPM	300.0	0.0	0.0	0.0	0.0	0.0	125.0	0.0	0.0	0.0	132.5	125.0	148.9
12. Net Summer Continuous Rating (MW)	NSC	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061
13. Operating British Thermal Units (GBTU)	OPR BTU	4,703.9	2,665.0	3,704.2	1,627.1	3,689.5	3,213.4	4,270.8	4,669.9	4,373.8	4,680.8	2,949.5	4,228.1	44,776.0
14. Net Generation (MWH)	NETGEN	682,239.1	377,898.0	527,688.0	213,900.0	517,263.0	449,778.0	592,883.0	673,696.0	658,273.7	676,742.0	417,852.0	611,288.0	6,399,500.8
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	6,894.7	7,052.0	7,020.0	7,607.0	7,134.0	7,144.0	7,204.0	6,932.0	6,912.0	6,917.0	7,050.0	6,917.0	6,996.8
16. Net Output Factor (%)	NOF	76.6	49.0	59.1	50.6	65.5	58.9	75.1	85.3	86.3	85.7	66.0	68.5	71.2

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ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 1		JAN 19	FEB 19	MAR 19	APR 19	MAY 19	JUN 19	JUL 19	AUG 19	SEP 19	OCT 19	NOV 19	DEC 19	2019
1. Equivalent Availability Factor (%)	EAF	99.9	87.8	23.1	87.9	93.9	95.4	86.7	96.8	97.5	78.1	67.5	98.6	85.1
2. Period Hours	PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
3. Service Hours	SH	744.0	597.1	0.0	586.9	714.1	700.1	672.5	728.2	708.2	602.7	467.8	736.3	7,257.9
4. Reserve Shutdown Hours	RSH	0.0	0.0	171.9	46.5	0.0	0.0	0.0	0.0	0.0	0.0	23.6	0.0	242.0
5. Unavailable Hours	UH	0.0	74.9	572.1	86.6	29.9	19.9	71.5	15.8	11.8	141.3	228.6	7.7	1,260.1
6. Planned Outage Hours	POH	0.0	74.9	572.1	8.5	0.0	0.0	0.0	0.0	0.0	114.4	203.7	0.0	973.6
7. Forced Outage Hours	FOH	0.0	0.0	0.0	78.1	0.0	19.9	68.5	10.8	10.2	24.7	14.0	7.7	233.9
8. Maintenance Outage Hours	MOH	0.0	0.0	0.0	0.0	29.9	0.0	3.0	5.0	1.6	2.2	10.8	0.0	52.5
9a. Partial Planned Outage Hours	PPOH	0.0	48.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48.5
9b. Load Reduction Partial Planned (MW)	LRPP	0.0	117.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.4
10a. Partial Forced Outage Hours	PFOH	2.1	0.0	0.0	0.9	0.0	39.7	81.7	16.1	12.8	36.9	16.8	10.0	217.0
10b. Load Reduction Partial Forced (MW)	LRPF	263.8	0.0	0.0	77.4	0.0	94.2	79.0	79.0	145.3	72.3	79.0	71.0	86.0
11a. Partial Maintenance Outage Hours	PMOH	0.0	0.0	0.0	0.0	44.6	7.7	0.0	7.4	2.4	20.3	0.0	0.0	82.5
11b. Load Reduction Partial Maintenance (MW)	LRPM	0.0	0.0	0.0	0.0	79.0	75.0	0.0	79.0	79.0	118.1	0.0	0.0	88.3
12. Net Summer Continuous Rating (MW)	NSC	701	701	701	701	701	701	701	701	701	701	701	701	701
13. Operating British Thermal Units (GBTU)	OPR BTU	2,153.7	1,975.7	0.0	2,092.3	2,623.6	2,709.4	2,338.2	2,555.4	2,098.8	1,848.1	1,146.7	2,090.2	23,632.0
14. Net Generation (MWH)	NETGEN	281,105.8	268,363.3	-489.0	285,493.0	357,594.0	371,287.2	316,400.6	340,370.5	282,565.0	249,882.7	153,636.9	286,572.2	3,192,782.2
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	7,661.4	7,362.0	0.0	7,329.0	7,337.0	7,297.0	7,390.0	7,508.0	7,428.0	7,396.0	7,464.0	7,294.0	7,401.7
16. Net Output Factor (%)	NOF	47.7	56.8	0.0	69.4	68.6	73.6	64.1	65.3	56.0	55.1	46.8	48.6	60.2

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EXHIBIT NO. ______ (JBC-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20200001-EI
DOCUMENT NO. 2
PAGE 3 OF 4

ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2		JAN 19	FEB 19	MAR 19	APR 19	MAY 19	JUN 19	JUL 19	AUG 19	SEP 19	OCT 19	NOV 19	DEC 19	2019
1. Equivalent Availability Factor (%)	EAF	33.7	80.8	99.5	94.1	99.6	99.3	100.0	92.1	97.4	100.0	71.8	46.1	85.5
2. Period Hours	PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
3. Service Hours	SH	241.8	594.0	740.6	691.2	742.1	717.2	743.0	685.1	707.6	744.0	597.6	155.5	7,359.7
4. Reserve Shutdown Hours	RSH	24.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	212.4	237.4
5. Unavailable Hours	UH	478.2	78.0	3.4	28.8	1.9	2.8	0.0	58.9	12.4	0.0	122.4	376.1	1,162.9
6. Planned Outage Hours	POH	445.0	58.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.4	372.6	998.0
7. Forced Outage Hours	FOH	33.2	0.0	3.4	28.8	0.5	2.8	0.0	0.0	0.0	0.0	0.0	3.5	72.2
8. Maintenance Outage Hours	MOH	0.0	20.0	0.0	0.0	1.4	0.0	0.0	58.9	12.4	0.0	0.0	0.0	92.9
9a. Partial Planned Outage Hours	PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9b. Load Reduction Partial Planned (MW)	LRPP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10a. Partial Forced Outage Hours	PFOH	0.7	383.8	0.2	53.4	1.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	445.1
10b. Load Reduction Partial Forced (MW)	LRPF	261.8	138.4	78.8	77.0	77.5	0.0	0.0	0.0	0.0	0.0	0.0	79.0	130.3
11a. Partial Maintenance Outage Hours	PMOH	59.9	0.0	0.0	0.0	2.7	8.3	0.0	0.0	24.2	0.0	164.2	41.9	301.2
11b. Load Reduction Partial Maintenance (MW)	LRPM	261.8	0.0	0.0	0.0	77.1	85.0	0.0	0.0	77.0	0.0	149.2	174.2	166.9
12. Net Summer Continuous Rating (MW)	NSC	929	929	929	929	929	929	929	929	929	929	929	929	929
13. Operating British Thermal Units (GBTU)	OPR BTU	661.3	2,265.6	4,330.1	3,601.5	4,030.2	3,898.4	3,798.3	3,042.7	2,946.1	3,292.3	2,204.7	365.9	34,437.1
14. Net Generation (MWH)	NETGEN	80,708.2	305,544.7	572,174.0	492,205.4	551,479.2	538,434.7	520,587.5	405,685.4	397,926.0	448,016.3	297,089.0	38,648.7	4,648,499.1
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	8,193.5	7,415.0	7,568.0	7,317.0	7,308.0	7,240.0	7,296.0	7,500.0	7,404.0	7,349.0	7,421.0	9,469.0	7,408.2
16. Net Output Factor (%)	NOF	31.9	49.1	86.9	73.6	77.5	80.5	75.3	63.7	59.5	64.8	44.4	23.7	64.9

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EXHIBIT NO. _____ (JBC-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20200001-EI
DOCUMENT NO. 2
PAGE 4 OF 4

EXHIBIT TO THE TESTIMONY

OF

JEREMY B. CAIN

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2021 – DECEMBER 2021

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 45
PARTY: TAMPA ELECTRIC COMPANY – DIRECT
DESCRIPTION: Jeremy B. Cain JC-1

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2021 - DECEMBER 2021
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2021 - DECEMBER 2021

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	14,003.9	7,002.0
+9	12,603.5	6,301.8
+8	11,203.1	5,601.6
+7	9,802.7	4,901.4
+6	8,402.4	4,201.2
+5	7,002.0	3,501.0
+4	5,601.6	2,800.8
+3	4,201.2	2,100.6
+2	2,800.8	1,400.4
+1	1,400.4	700.2
0	0.0	0.0
-1	(1,450.1)	(700.2)
-2	(2,900.2)	(1,400.4)
-3	(4,350.3)	(2,100.6)
-4	(5,800.4)	(2,800.8)
-5	(7,250.5)	(3,501.0)
-6	(8,700.6)	(4,201.2)
-7	(10,150.7)	(4,901.4)
-8	(11,600.7)	(5,601.6)
-9	(13,050.8)	(6,301.8)
-10	(14,500.9)	(7,002.0)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2021 - DECEMBER 2021

Line 1	Beginning of period balance of common equity: End of month common equity:		$	3,546,437,770	
Line 2	Month of January	2021	$	3,457,175,770	
Line 3	Month of February	2021	$	3,486,705,814	
Line 4	Month of March	2021	$	3,516,488,092	
Line 5	Month of April	2021	$	3,576,474,440	
Line 6	Month of May	2021	$	3,607,023,492	
Line 7	Month of June	2021	$	3,637,833,484	
Line 8	Month of July	2021	$	3,547,561,253	
Line 9	Month of August	2021	$	3,577,863,339	
Line 10	Month of September	2021	$	3,608,424,255	
Line 11	Month of October	2021	$	3,668,655,442	
Line 12	Month of November	2021	$	3,699,991,873	
Line 13	Month of December	2021	$	3,731,595,971	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	3,589,402,384	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			74.76%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	12,003,035	
Line 18	Jurisdictional Sales			19,545,089	MWH
Line 19	Total Sales			19,545,089	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			100.00%	
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)		$	12,003,035	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)		$	7,001,961	
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)		$	7,001,961	

Note: Line 22 and 23 are as approved by Commission order PSC-13-0665-FOF-EI dated 12/18/13 effective 1/1/14.

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TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2021 - DECEMBER 2021

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 4	1.29%	54.0	60.7	40.4	181.0	(860.3)
POLK 1	4.82%	77.7	82.1	72.4	675.5	(1,134.0)
POLK 2	1.53%	80.6	82.1	77.7	213.7	(1,325.4)
BAYSIDE 1	16.01%	93.9	94.5	92.6	2,242.6	(74.8)
BAYSIDE 2	7.45%	90.9	92.2	88.5	1,043.8	(1,459.2)
GPIF SYSTEM	**31.11%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR Btu/kwh	TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 4	13.68%	11,576	43.0	10,961	12,191	1,916.4	(1,916.4)
POLK 1	8.34%	9,684	82.1	9,020	10,348	1,167.3	(1,167.3)
POLK 2	23.74%	6,940	81.0	6,755	7,125	3,324.1	(3,324.1)
BAYSIDE 1	10.83%	7,352	79.6	7,244	7,460	1,516.3	(1,516.3)
BAYSIDE 2	12.31%	7,439	63.3	7,317	7,560	1,723.2	(1,723.2)
GPIF SYSTEM	**68.89%**						

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 21 - DEC 21 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 19 - DEC 19 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 18 - DEC 18 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 17 - DEC 17 POF	EUOF	EUOR
BIG BEND 4	1.29%	4.2%	16.2	29.9	35.6	16.5	28.0	39.8	19.1	20.6	26.6	0.0	30.7	31.2
POLK 1	4.82%	15.5%	7.7	14.6	15.8	6.7	14.9	22.8	28.1	10.7	16.3	4.4	9.6	10.4
POLK 2	1.53%	4.9%	16.2	3.2	3.8	4.5	3.7	3.8	2.0	3.3	3.2	1.8	6.9	7.8
BAYSIDE 1	16.01%	51.5%	3.8	2.3	2.4	11.1	6.7	7.4	5.3	1.6	1.7	11.6	2.0	2.4
BAYSIDE 2	7.45%	24.0%	3.8	5.2	5.4	12.8	4.0	4.5	19.6	2.5	3.1	9.4	5.1	5.7
GPIF SYSTEM	**31.11%**	**100.0%**	**5.5**	**6.1**	**6.6**	**10.7**	**8.0**	**10.3**	**12.7**	**4.1**	**5.4**	**9.0**	**5.4**	**5.9**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**88.4**			**81.2**			**83.2**			**85.7**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
10.8	**5.8**	**7.2**	**83.4**

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AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 21 - DEC 21	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 19 - DEC 19	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 18 - DEC 18	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 17 - DEC 17
BIG BEND 4	13.68%	19.9%	11,576	11,434	11,564	11,502
POLK 1	8.34%	12.1%	9,684	8,864	10,359	10,065
POLK 2	23.74%	34.5%	6,940	6,919	6,922	6,920
BAYSIDE 1	10.83%	15.7%	7,352	7,324	7,354	7,300
BAYSIDE 2	12.31%	17.9%	7,439	7,437	7,309	7,868
GPIF SYSTEM	**68.89%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**8,347**	**8,207**	**8,397**	**8,440**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2021 - DECEMBER 2021
PRODUCTION COSTING SIMULATION
FUEL COST ($000)

UNIT PERFORMANCE INDICATOR	AT TARGET (1)	AT MAXIMUM IMPROVEMENT (2)	SAVINGS (3)	WEIGHTING FACTOR (% OF SAVINGS)
EQUIVALENT AVAILABILITY				
EA_3 BIG BEND 4	459,381.86	459,200.83	181.0	1.29%
EA_1 POLK 1	459,381.86	458,706.38	675.5	4.82%
EA_2 POLK 2	459,381.86	459,168.18	213.7	1.53%
EA_3 BAYSIDE 1	459,381.86	457,139.22	2,242.6	16.01%
EA_4 BAYSIDE 2	459,381.86	458,338.03	1,043.8	7.45%
AVERAGE HEAT RATE				
AHR_3 BIG BEND 4	459,381.86	457,465.48	1,916.4	13.68%
AHR_1 POLK 1	459,381.86	458,214.59	1,167.3	8.34%
AHR_2 POLK 2	459,381.86	456,057.72	3,324.1	23.74%
AHR_3 BAYSIDE 1	459,381.86	457,865.60	1,516.3	10.83%
AHR_4 BAYSIDE 2	459,381.86	457,658.65	1,723.2	12.31%
TOTAL SAVINGS			**14,003.92**	**100.00%**

(1) Fuel Adjustment Base Case - All unit performance indicators at target.
(2) All other units performance indicators at target.
(3) Expressed in replacement energy cost.

GPIF TARGET AND RANGE SUMMARY

JANUARY 2021 - DECEMBER 2021

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	181.0	60.7	+10	1,916.4	10,961
+9	162.9	64.7	+9	1,724.7	9,857
+8	144.8	68.6	+8	1,533.1	8,754
+7	126.7	72.5	+7	1,341.5	7,650
+6	108.6	76.4	+6	1,149.8	6,546
+5	90.5	80.4	+5	958.2	5,443
+4	72.4	84.3	+4	766.6	4,339
+3	54.3	88.2	+3	574.9	3,236
+2	36.2	92.1	+2	383.3	2,132
+1	18.1	96.1	+1	191.6	1,029
					(75)
0	0.0	100.0	0	0.0	0
					75
-1	(86.0)	94.0	-1	(191.6)	1,287
-2	(172.1)	88.1	-2	(383.3)	2,498
-3	(258.1)	82.1	-3	(574.9)	3,710
-4	(344.1)	76.2	-4	(766.6)	4,921
-5	(430.1)	70.2	-5	(958.2)	6,133
-6	(516.2)	64.2	-6	(1,149.8)	7,344
-7	(602.2)	58.3	-7	(1,341.5)	8,556
-8	(688.2)	52.3	-8	(1,533.1)	9,768
-9	(774.2)	46.4	-9	(1,724.7)	10,979
-10	(860.3)	40.4	-10	(1,916.4)	12,191

Weighting Factor = 1.29%

Weighting Factor = 13.68%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2021 - DECEMBER 2021

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	675.5	82.1	+10	1,167.3	9,020
+9	607.9	81.6	+9	1,050.5	9,079
+8	540.4	81.2	+8	933.8	9,138
+7	472.8	80.8	+7	817.1	9,197
+6	405.3	80.3	+6	700.4	9,256
+5	337.7	79.9	+5	583.6	9,315
+4	270.2	79.5	+4	466.9	9,374
+3	202.6	79.0	+3	350.2	9,433
+2	135.1	78.6	+2	233.5	9,491
+1	67.5	78.2	+1	116.7	9,550
					9,609
0	0.0	77.7	0	0.0	9,684
					9,759
-1	(113.4)	77.2	-1	(116.7)	9,818
-2	(226.8)	76.7	-2	(233.5)	9,877
-3	(340.2)	76.1	-3	(350.2)	9,936
-4	(453.6)	75.6	-4	(466.9)	9,995
-5	(567.0)	75.0	-5	(583.6)	10,054
-6	(680.4)	74.5	-6	(700.4)	10,112
-7	(793.8)	74.0	-7	(817.1)	10,171
-8	(907.2)	73.4	-8	(933.8)	10,230
-9	(1,020.6)	72.9	-9	(1,050.5)	10,289
-10	(1,134.0)	72.4	-10	(1,167.3)	10,348
	Weighting Factor =	4.82%		Weighting Factor =	8.34%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2021 - DECEMBER 2021

POLK 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	213.7	82.1	+10	3,324.1	6,755
+9	192.3	81.9	+9	2,991.7	6,766
+8	170.9	81.8	+8	2,659.3	6,777
+7	149.6	81.6	+7	2,326.9	6,788
+6	128.2	81.5	+6	1,994.5	6,799
+5	106.8	81.3	+5	1,662.1	6,810
+4	85.5	81.2	+4	1,329.7	6,821
+3	64.1	81.1	+3	997.2	6,832
+2	42.7	80.9	+2	664.8	6,843
+1	21.4	80.8	+1	332.4	6,854
					6,865
0	0.0	80.6	0	0.0	6,940
					7,015
-1	(132.5)	80.3	-1	(332.4)	7,026
-2	(265.1)	80.0	-2	(664.8)	7,037
-3	(397.6)	79.7	-3	(997.2)	7,048
-4	(530.2)	79.5	-4	(1,329.7)	7,059
-5	(662.7)	79.2	-5	(1,662.1)	7,070
-6	(795.2)	78.9	-6	(1,994.5)	7,081
-7	(927.8)	78.6	-7	(2,326.9)	7,092
-8	(1,060.3)	78.3	-8	(2,659.3)	7,103
-9	(1,192.9)	78.0	-9	(2,991.7)	7,114
-10	(1,325.4)	77.7	-10	(3,324.1)	7,125
	Weighting Factor =	1.53%		Weighting Factor =	23.74%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2021 - DECEMBER 2021

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	2,242.6	94.5	+10	1,516.3	7,244
+9	2,018.4	94.5	+9	1,364.6	7,247
+8	1,794.1	94.4	+8	1,213.0	7,251
+7	1,569.8	94.3	+7	1,061.4	7,254
+6	1,345.6	94.3	+6	909.8	7,257
+5	1,121.3	94.2	+5	758.1	7,261
+4	897.1	94.1	+4	606.5	7,264
+3	672.8	94.1	+3	454.9	7,267
+2	448.5	94.0	+2	303.3	7,271
+1	224.3	93.9	+1	151.6	7,274
					7,277
0	0.0	93.9	0	0.0	7,352
					7,427
-1	(7.5)	93.7	-1	(151.6)	7,431
-2	(15.0)	93.6	-2	(303.3)	7,434
-3	(22.4)	93.5	-3	(454.9)	7,437
-4	(29.9)	93.4	-4	(606.5)	7,441
-5	(37.4)	93.2	-5	(758.1)	7,444
-6	(44.9)	93.1	-6	(909.8)	7,447
-7	(52.4)	93.0	-7	(1,061.4)	7,451
-8	(59.8)	92.8	-8	(1,213.0)	7,454
-9	(67.3)	92.7	-9	(1,364.6)	7,457
-10	(74.8)	92.6	-10	(1,516.3)	7,460

Weighting Factor = 16.01% Weighting Factor = 10.83%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2021 - DECEMBER 2021

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,043.8	92.2	+10	1,723.2	7,317
+9	939.4	92.1	+9	1,550.9	7,322
+8	835.1	91.9	+8	1,378.6	7,326
+7	730.7	91.8	+7	1,206.2	7,331
+6	626.3	91.7	+6	1,033.9	7,336
+5	521.9	91.6	+5	861.6	7,340
+4	417.5	91.4	+4	689.3	7,345
+3	313.1	91.3	+3	517.0	7,350
+2	208.8	91.2	+2	344.6	7,354
+1	104.4	91.1	+1	172.3	7,359
					7,364
0	0.0	90.9	0	0.0	7,439
					7,514
-1	(145.9)	90.7	-1	(172.3)	7,518
-2	(291.8)	90.5	-2	(344.6)	7,523
-3	(437.8)	90.2	-3	(517.0)	7,528
-4	(583.7)	90.0	-4	(689.3)	7,532
-5	(729.6)	89.7	-5	(861.6)	7,537
-6	(875.5)	89.5	-6	(1,033.9)	7,541
-7	(1,021.4)	89.2	-7	(1,206.2)	7,546
-8	(1,167.4)	89.0	-8	(1,378.6)	7,551
-9	(1,313.3)	88.7	-9	(1,550.9)	7,555
-10	(1,459.2)	88.5	-10	(1,723.2)	7,560
	Weighting Factor =	7.45%		Weighting Factor =	12.31%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2021 - DECEMBER 2021

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021
1. EAF (%)	64.4	57.5	41.5	64.4	64.4	64.4	64.4	64.4	64.4	64.4	8.6	24.9	54.0
2. POF	0.0	10.7	35.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.7	61.3	16.2
3. EUOF	35.6	31.8	23.0	35.6	35.6	35.6	35.6	35.6	35.6	35.6	4.8	13.8	29.9
4. EUOR	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	615	556	147	377	615	595	615	615	595	260	0	238	5,228
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	129	116	597	343	129	125	129	129	125	484	720	506	3,532
9. POH	0	72	264	0	0	0	0	0	0	0	624	456	1,416
10. EFOH	158	127	102	153	158	153	158	158	153	158	20	61	1,557
11. EMOH	107	87	69	104	107	104	107	107	104	107	14	42	1,060
12. OPER BTU (GBTU)	1,184	1,075	354	742	1,365	1,319	1,343	1,379	1,291	566	0	436	11,061
13. NET GEN (MWH)	101,280	92,020	30,950	63,690	118,600	114,520	116,420	119,950	111,870	49,110	0	37,160	955,570
14. ANOHR (Btu/kwh)	11,689	11,684	11,442	11,644	11,512	11,514	11,532	11,500	11,539	11,534	12,575	11,735	11,576
15. NOF (%)	38.1	38.3	48.7	40.0	45.7	45.6	44.9	46.2	44.6	44.8	0.0	36.1	43.0
16. NPC (MW)	432	432	432	422	422	422	422	422	422	422	422	432	425

17. ANOHR EQUATION ANOHR = NOF(-23.261) + 12,575

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ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2021 - DECEMBER 2021

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021
1. EAF (%)	84.2	84.2	84.2	84.2	46.2	84.2	84.2	84.2	84.2	84.2	78.6	51.6	77.7
2. POF	0.0	0.0	0.0	0.0	45.2	0.0	0.0	0.0	0.0	0.0	6.7	38.7	7.7
3. EUOF	15.8	15.8	15.8	15.8	8.7	15.8	15.8	15.8	15.8	15.8	14.7	9.7	14.6
4. EUOR	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	112	306	360	214	192	320	345	289	309	484	214	16	3,161
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	632	366	384	506	552	400	399	455	411	260	506	728	5,599
9. POH	0	0	0	0	336	0	0	0	0	0	48	288	672
10. EFOH	39	35	39	38	21	38	39	39	38	39	35	24	422
11. EMOH	79	71	79	76	43	76	79	79	76	79	71	48	856
12. OPER BTU (GBTU)	181	495	612	359	339	557	600	510	540	870	352	26	5,443
13. NET GEN (MWH)	18,560	50,920	63,050	37,040	35,110	57,590	62,100	52,750	55,880	90,050	36,350	2,640	562,040
14. ANOHR (Btu/kwh)	9,726	9,725	9,709	9,683	9,663	9,669	9,669	9,664	9,667	9,657	9,689	9,727	9,684
15. NOF (%)	72.0	72.4	76.1	82.4	87.1	85.7	85.7	86.9	86.1	88.6	80.9	71.7	82.1
16. NPC (MW)	230	230	230	210	210	210	210	210	210	210	210	230	217
17. ANOHR EQUATION	ANOHR = NOF(		-4.177	) +	10,027								

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ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2021 - DECEMBER 2021

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 2	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021
1. EAF (%)	96.2	0.0	43.4	96.2	96.2	96.2	96.2	96.2	96.2	52.7	96.2	96.2	80.6
2. POF	0.0	100.0	54.8	0.0	0.0	0.0	0.0	0.0	0.0	45.2	0.0	0.0	16.2
3. EUOF	3.8	0.0	1.7	3.8	3.8	3.8	3.8	3.8	3.8	2.1	3.8	3.8	3.2
4. EUOR	3.8	0.0	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	723	0	678	709	733	709	733	733	706	402	709	728	7,563
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	21	672	66	11	11	11	11	11	14	342	11	16	1,197
9. POH	0	672	408	0	0	0	0	0	0	336	0	0	1,416
10. EFOH	10	0	5	10	10	10	10	10	10	6	10	10	101
11. EMOH	18	0	8	18	18	18	18	18	18	10	18	18	181
12. OPER BTU (GBTU)	4,459	0	4,674	4,404	4,437	4,419	4,434	4,435	4,410	2,449	4,418	4,462	47,042
13. NET GEN (MWH)	637,090	0	675,000	637,350	640,390	639,680	639,870	640,040	638,510	353,640	639,490	637,090	6,778,150
14. ANOHR (Btu/kwh)	7,000	0	6,924	6,910	6,929	6,908	6,930	6,930	6,906	6,925	6,908	7,004	6,940
15. NOF (%)	73.4	0.0	83.0	84.7	82.3	85.0	82.3	82.3	85.2	82.9	85.0	72.9	81.0
16. NPC (MW)	1,200	1,200	1,200	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,200	1,107

17. ANOHR EQUATION ANOHR = NOF(-7.900) + 7,580

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ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2021 - DECEMBER 2021

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 1	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021
1. EAF (%)	97.6	97.6	53.5	97.6	97.6	97.6	97.6	97.6	97.6	97.6	97.6	97.6	93.9
2. POF	0.0	0.0	45.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8
3. EUOF	2.4	2.4	1.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.3
4. EUOR	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	726	656	395	701	726	702	725	725	702	725	702	672	8,157
7. RSH	0	0	3	2	0	1	1	1	1	1	1	54	67
8. UH	18	16	346	17	18	17	18	18	17	18	17	18	536
9. POH	0	0	336	0	0	0	0	0	0	0	0	0	336
10. EFOH	8	8	5	8	8	8	8	8	8	8	8	8	95
11. EMOH	9	8	5	9	9	9	9	9	9	9	9	9	106
12. OPER BTU (GBTU)	2,368	3,423	1,960	2,832	3,030	3,118	3,241	3,283	3,244	3,064	2,840	2,478	34,916
13. NET GEN (MWH)	317,840	468,270	267,460	384,950	412,470	425,620	442,670	448,630	443,730	417,380	386,040	334,020	4,749,080
14. ANOHR (Btu/kwh)	7,450	7,310	7,329	7,357	7,347	7,325	7,322	7,318	7,310	7,342	7,357	7,420	7,352
15. NOF (%)	55.3	90.1	85.5	78.3	81.0	86.5	87.1	88.3	90.2	82.1	78.4	62.8	79.6
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(		-4.013	) +	7,672								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2021 - DECEMBER 2021

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021
1. EAF (%)	94.6	94.6	94.6	94.6	94.6	94.6	94.6	94.6	94.6	94.6	50.4	94.6	90.9
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.7	0.0	3.8
3. EUOF	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	2.9	5.4	5.2
4. EUOR	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	502	635	703	680	703	680	703	703	680	703	360	691	7,743
7. RSH	202	1	1	1	1	1	1	1	1	1	3	13	224
8. UH	40	36	40	39	40	39	40	40	39	40	357	40	793
9. POH	0	0	0	0	0	0	0	0	0	0	336	0	336
10. EFOH	11	10	11	11	11	11	11	11	11	11	6	11	129
11. EMOH	29	26	29	28	29	28	29	29	28	29	15	29	329
12. OPER BTU (GBTU)	1,397	3,607	3,886	2,642	2,607	3,187	3,404	3,511	3,544	3,705	1,435	2,031	35,271
13. NET GEN (MWH)	175,410	498,850	534,170	348,580	341,680	434,050	466,630	484,510	493,800	517,730	190,040	256,200	4,741,650
14. ANOHR (Btu/kwh)	7,964	7,231	7,275	7,581	7,631	7,343	7,294	7,246	7,176	7,157	7,552	7,928	7,439
15. NOF (%)	33.4	75.0	72.6	55.2	52.3	68.7	71.4	74.2	78.2	79.3	56.8	35.4	63.3
16. NPC (MW)	1,047	1,047	1,047	929	929	929	929	929	929	929	929	1,047	968
17. ANOHR EQUATION	ANOHR = NOF(	-17.589	) +	8,551									

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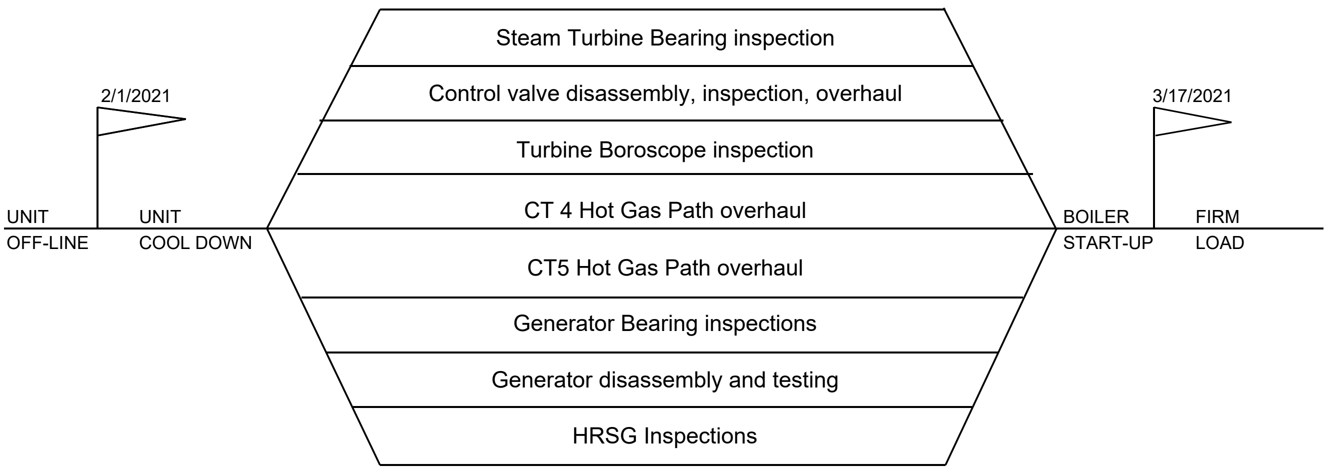
TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2021 - DECEMBER 2021

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 4	Mar 29	-	Apr 11	Fuel System Clean-up Planned Outage
+		Nov 05	-	Dec 19	NG upgrade to the boiler-Corporate Strategic Driven, Replacement of the A&B ID Fan inlet ductwork Replacement of the FGD LE conveyor Replacement of selected FGD transformers Replacement of MS,HR and CRH piping hangers Replacement of Furnace roof tubes Replacement of Coal Nozzles-Maintenance Replacement of SH Link Header
	POLK 1	May 15	-	May 28	Combined Cycle Planned Outage
		Nov 29	-	Dec 12	Combined Cycle Planned Outage
+	POLK 2	Feb 01	-	Mar 17	Control valve disassembly, inspection, overhaul Steam Turbine Bearing inspection Turbine Boroscope inspection CT 4 Hot Gas Path overhaul CT5 Hot Gas Path overhaul Generator Bearing inspections Generator disassembly and testing HRSG Inspections
		Oct 08	-	Oct 21	Combined Cycle Planned Outage
	BAYSIDE 1	Mar 15	-	Mar 28	Combined Cycle Planned Outage
	BAYSIDE 2	Nov 11	-	Nov 24	Combined Cycle Planned Outage

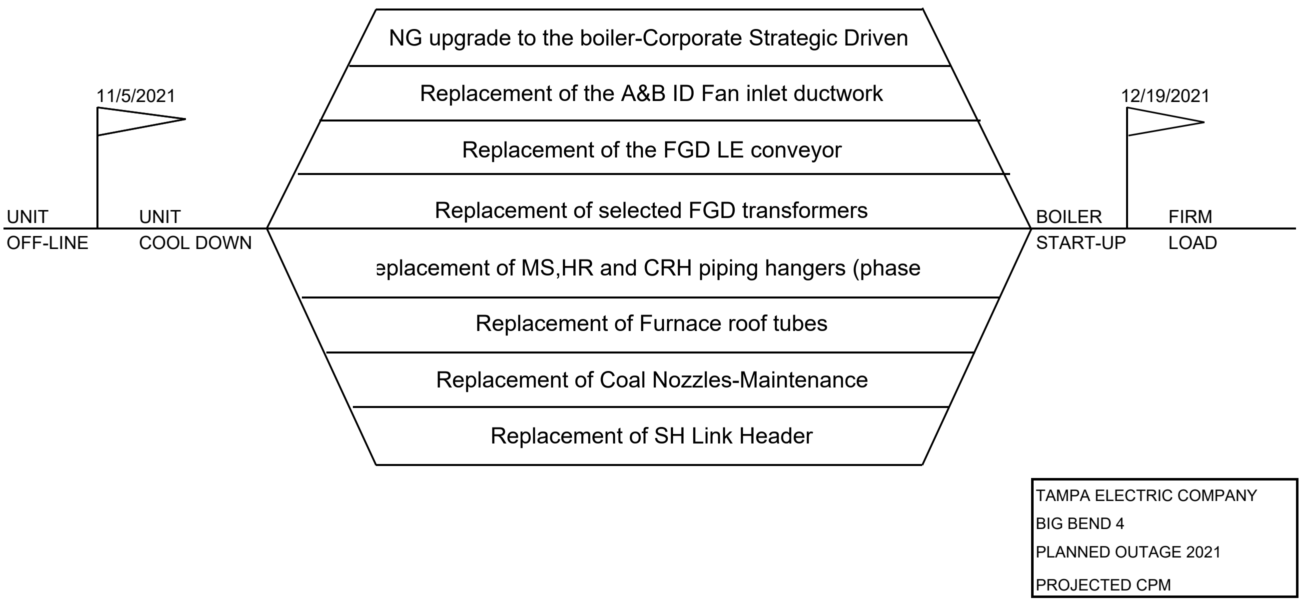
+ These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2021 - DECEMBER 2021

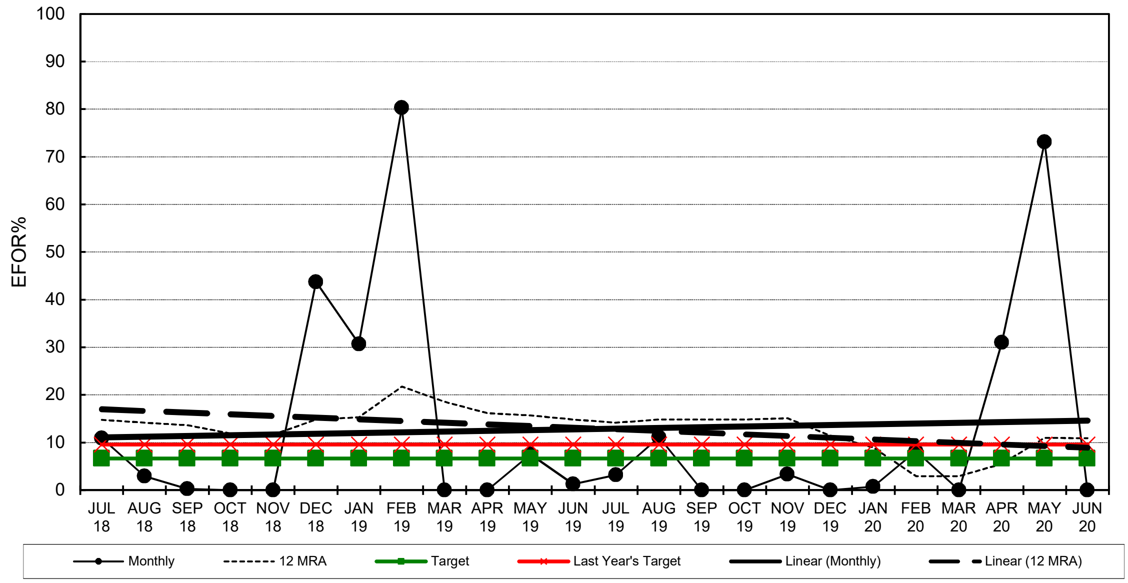


TAMPA ELECTRIC COMPANY
POLK 2
PLANNED OUTAGE 2021
PROJECTED CPM

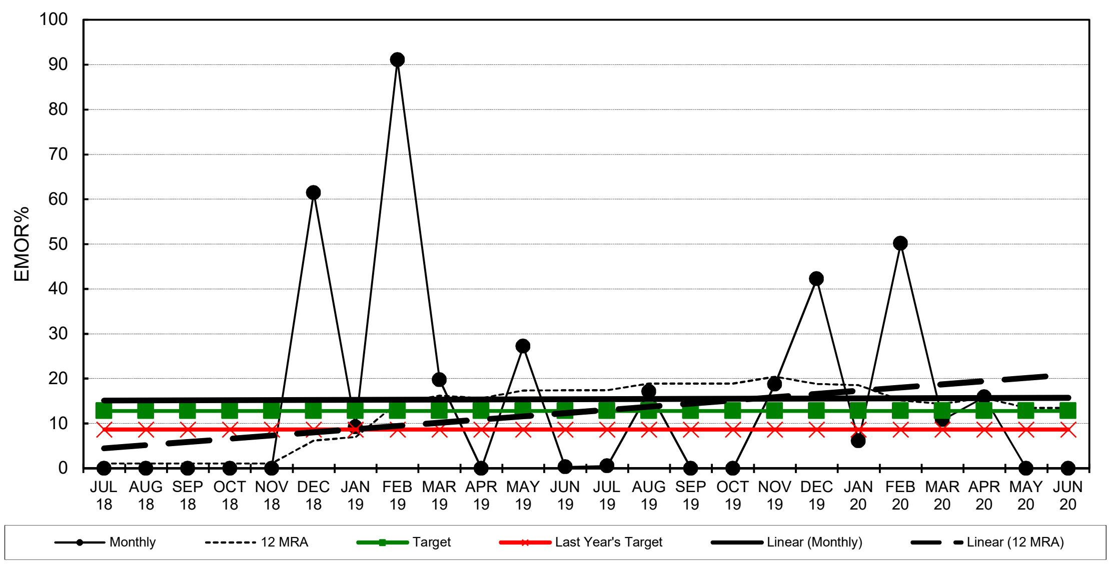
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2021 - DECEMBER 2021

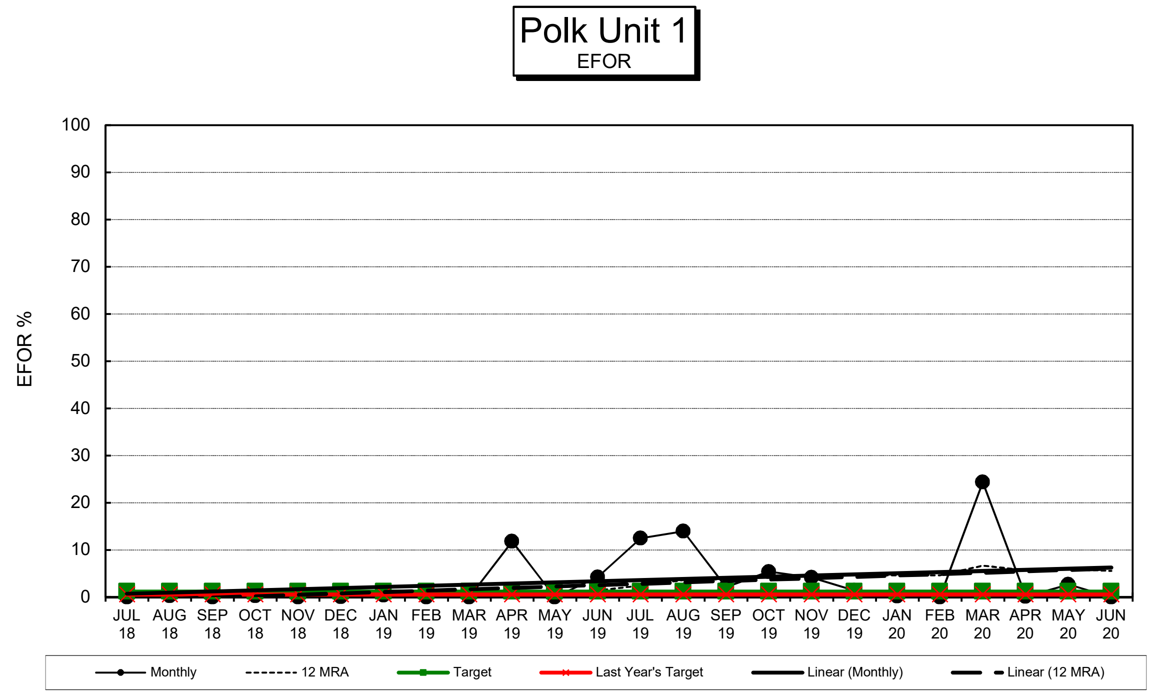


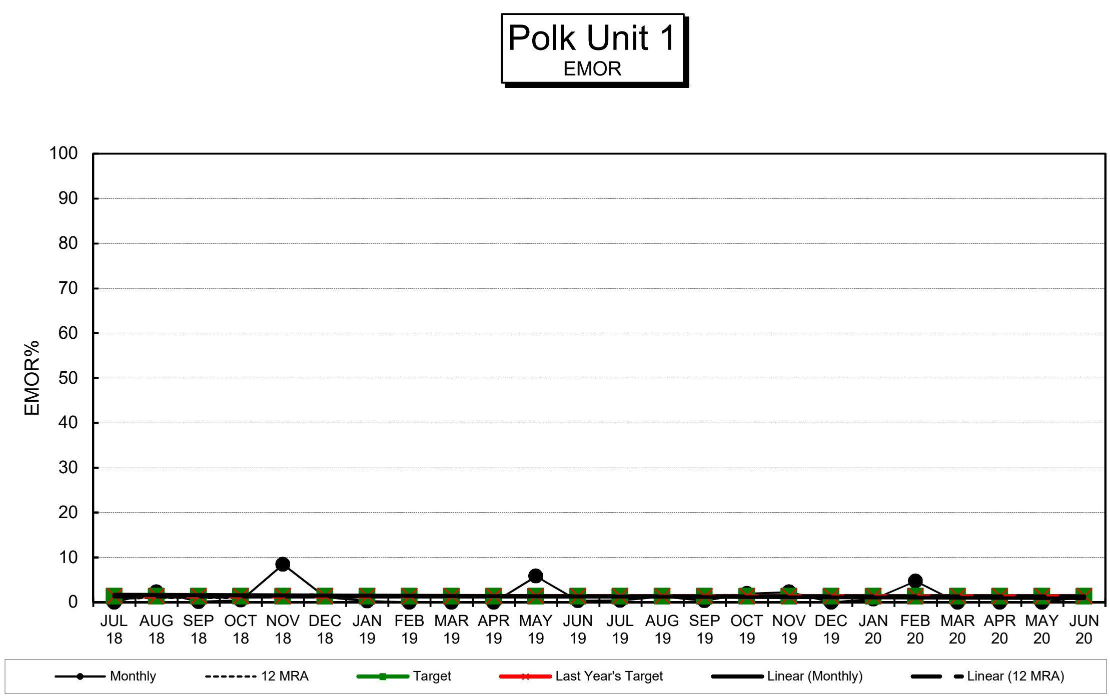
Big Bend Unit 4
EFOR

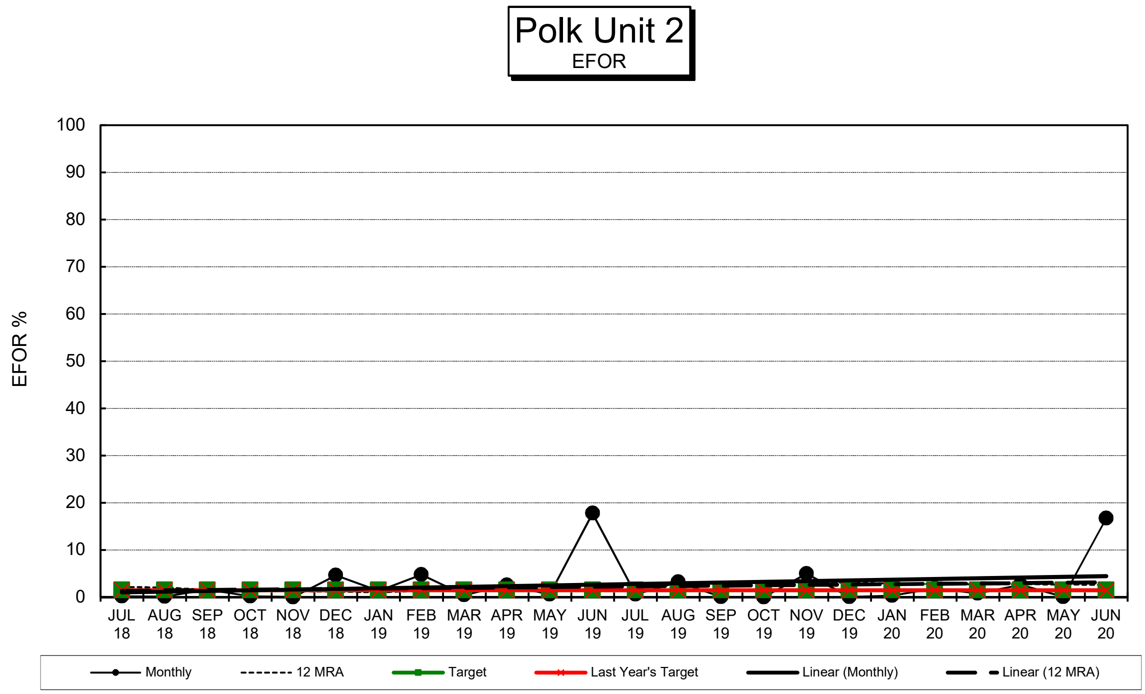


Big Bend Unit 4
EMOR




Polk Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
JUL 19
AUG 19
SEP 19
OCT 19
NOV 19
DEC 19
JAN 20
FEB 20
MAR 20
APR 20
MAY 20
JUN 20
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
JUL 19
AUG 19
SEP 19
OCT 19
NOV 19
DEC 19
JAN 20
FEB 20
MAR 20
APR 20
MAY 20
JUN 20
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 2
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
JUL 19
AUG 19
SEP 19
OCT 19
NOV 19
DEC 19
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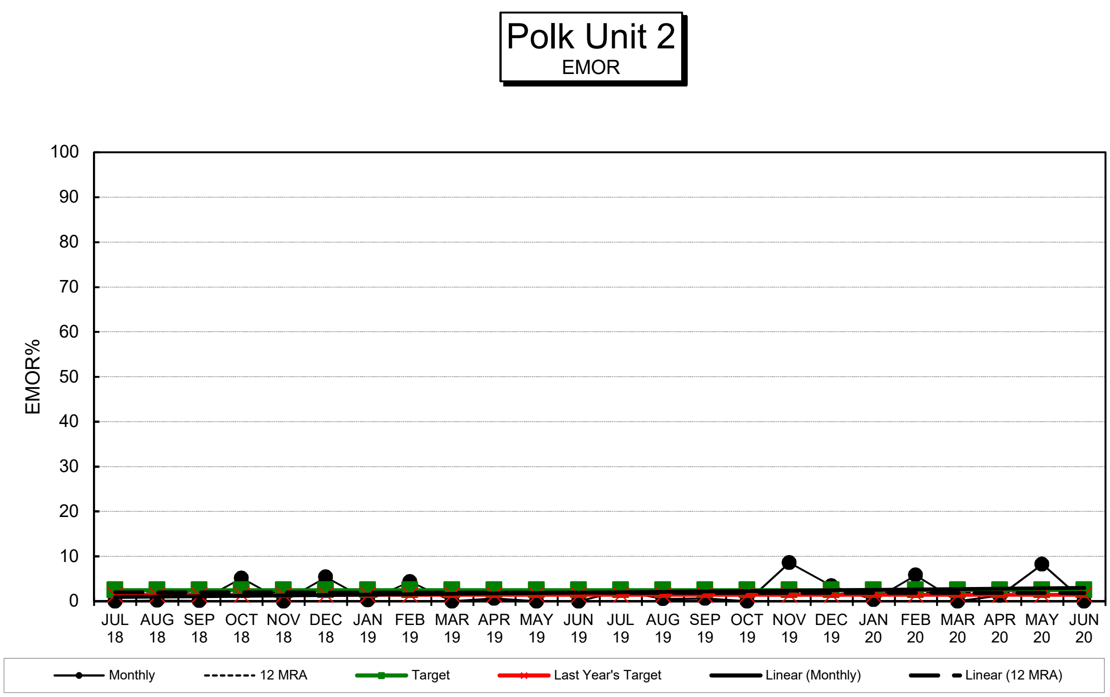
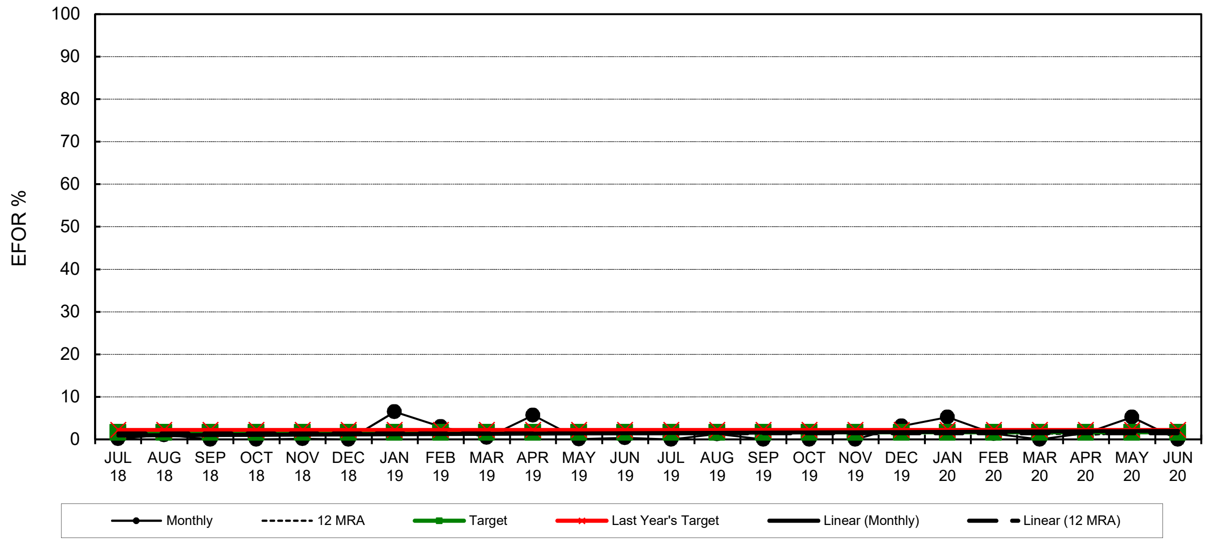
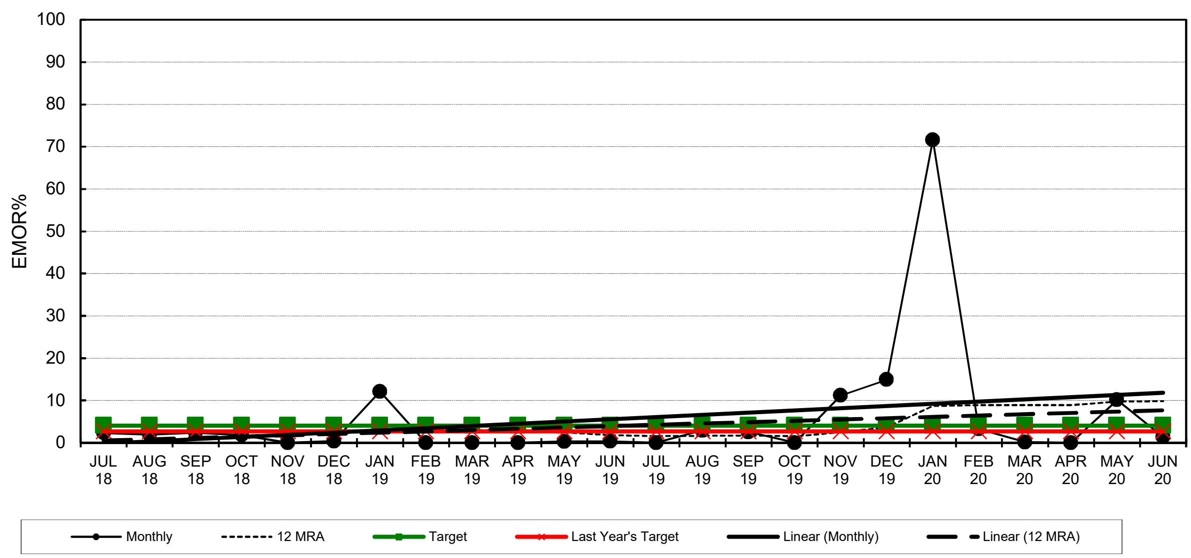
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 2
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
JUL 19
AUG 19
SEP 19
OCT 19
NOV 19
DEC 19
JAN 20
FEB 20
MAR 20
APR 20
MAY 20
JUN 20
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

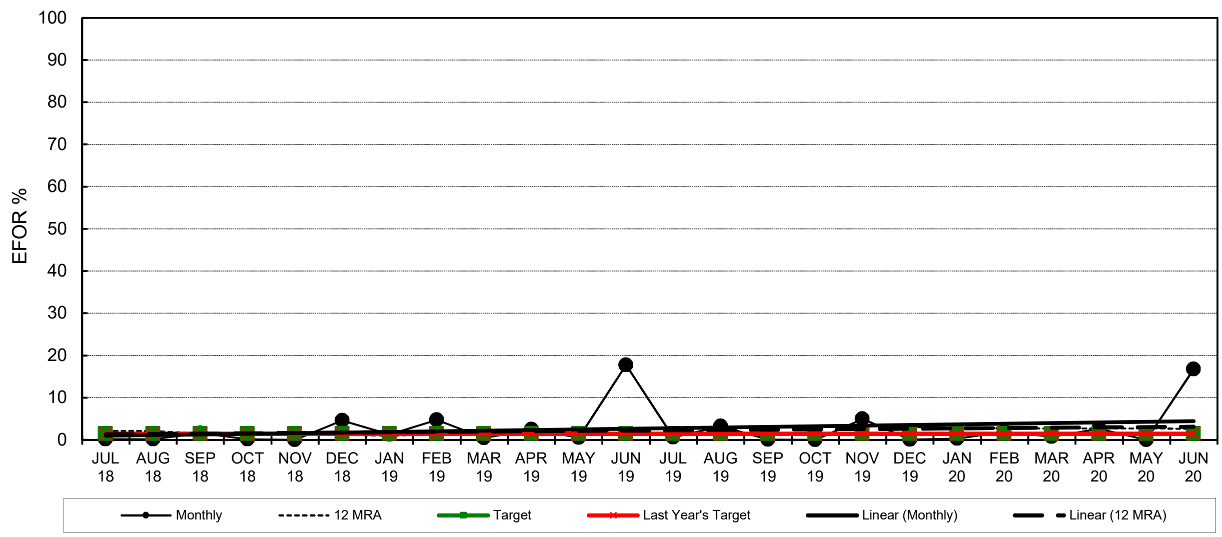
Bayside Unit 1
EFOR



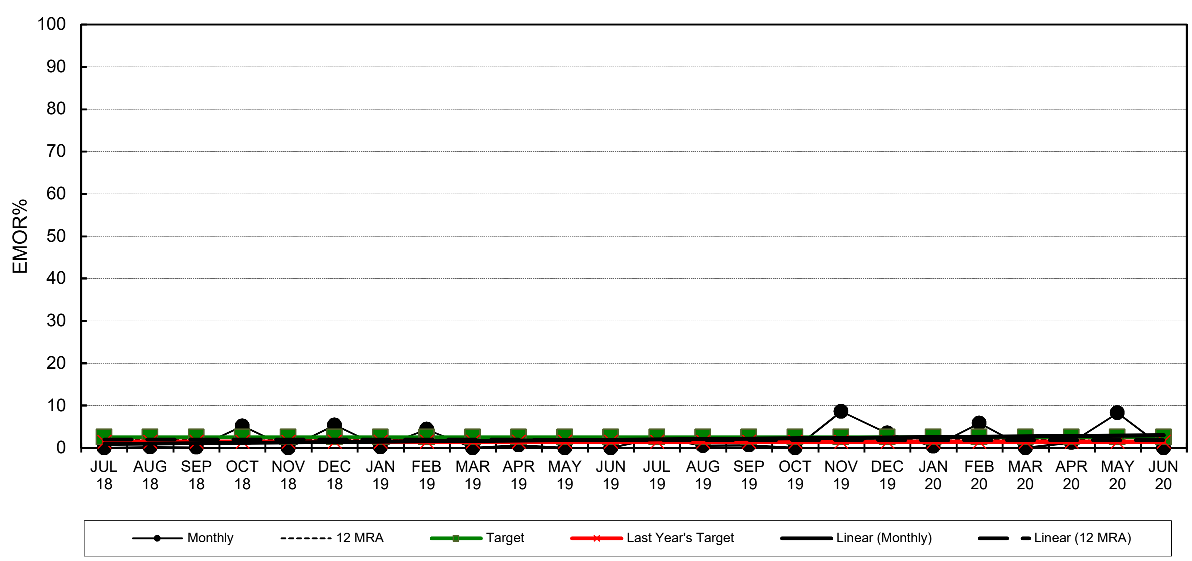
Bayside Unit 1
EMOR



Bayside Unit 2
EFOR



Bayside Unit 2
EMOR



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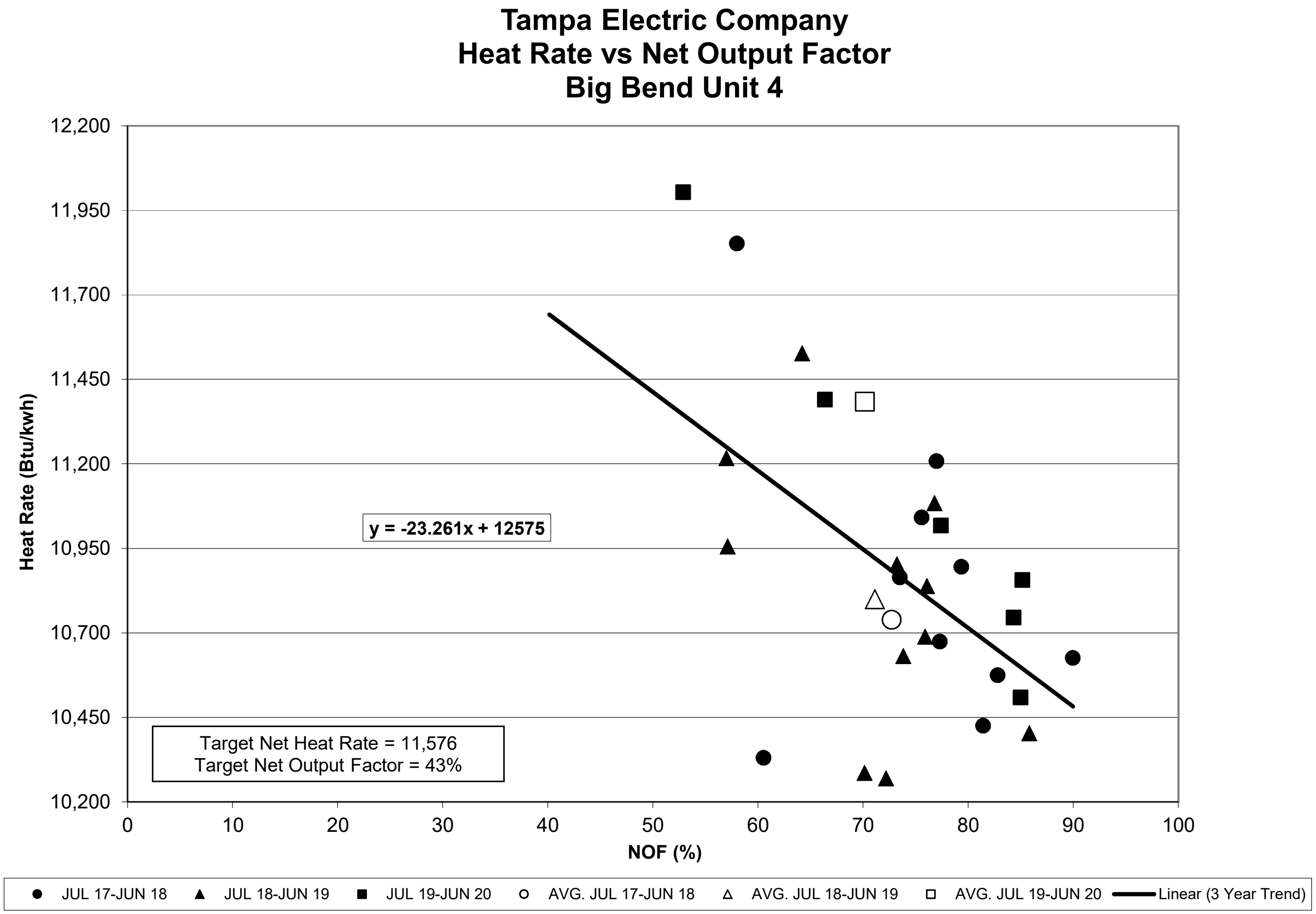

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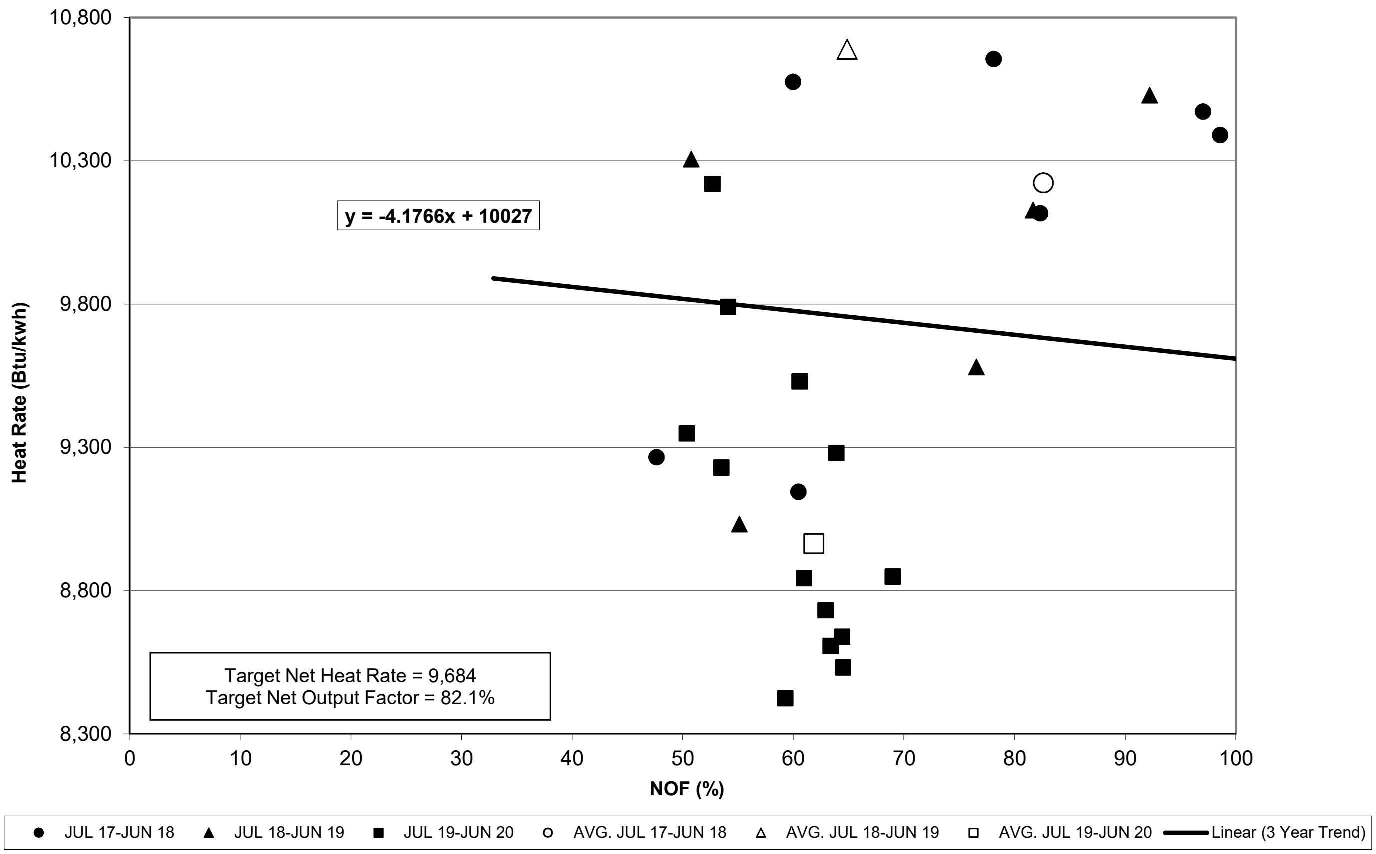
Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1



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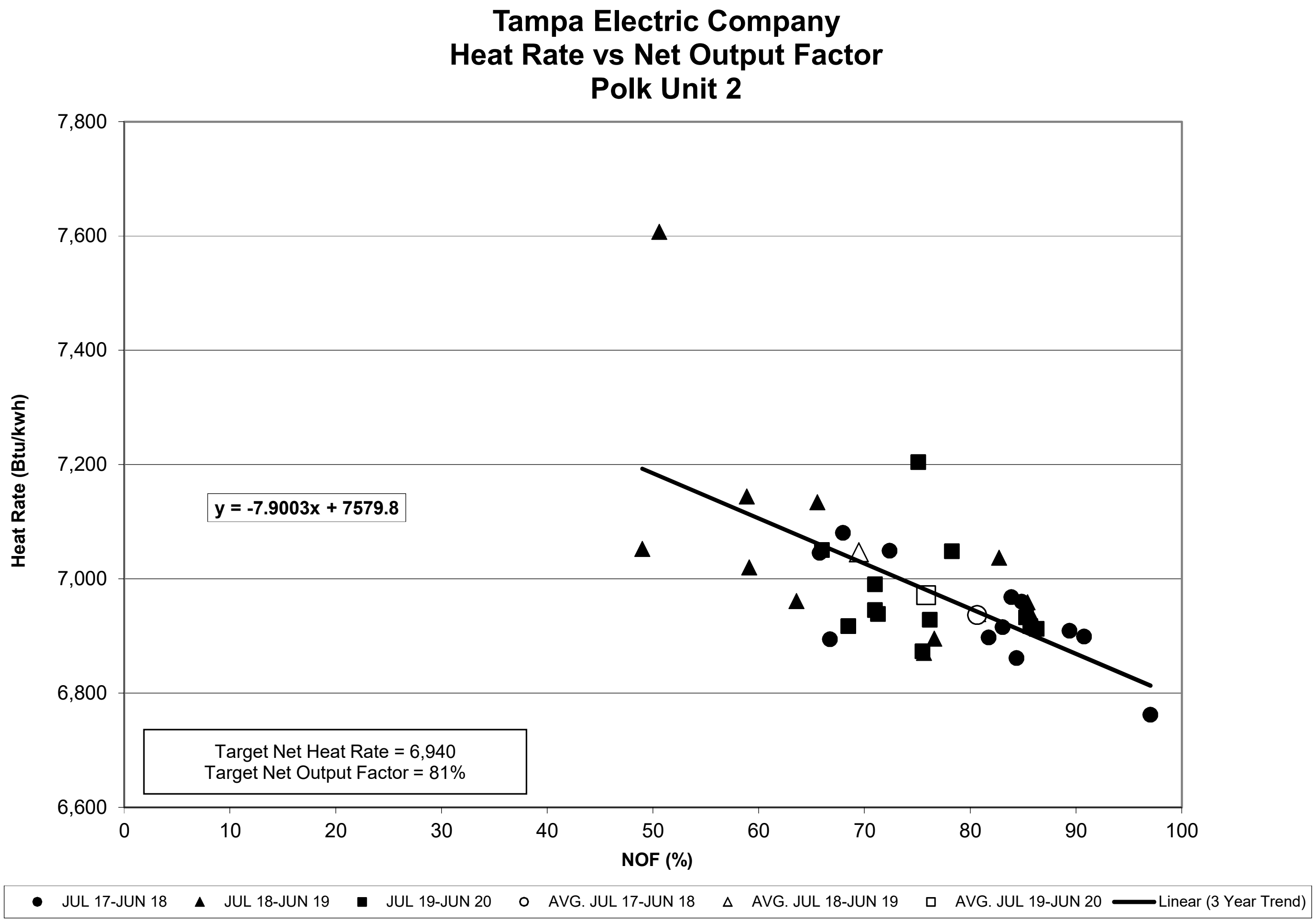

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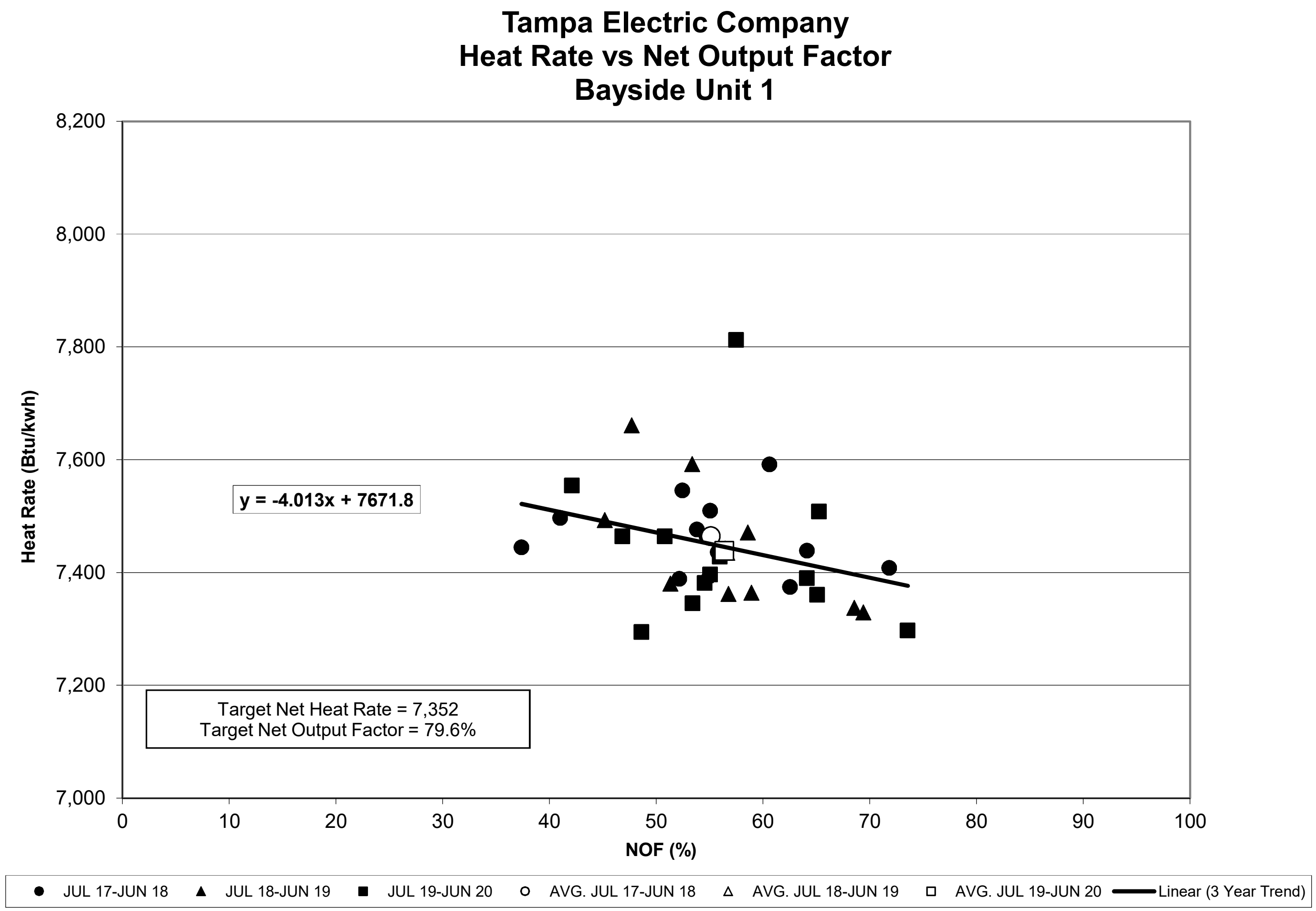

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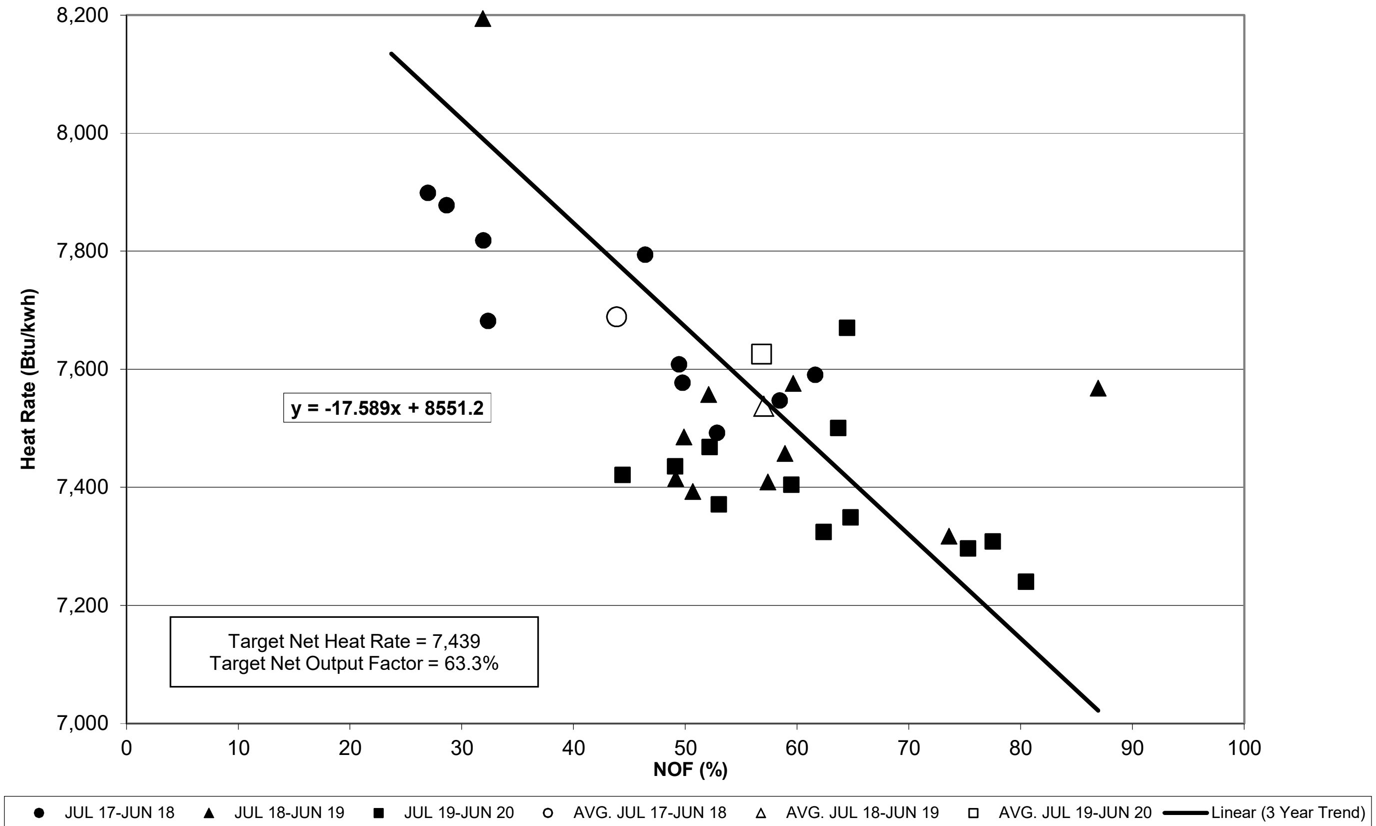
Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2



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TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2021 - DECEMBER 2021

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 4		458	425
POLK 1		225	217
POLK 2		1,130	1,107
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,533	3,449
	SYSTEM TOTAL	**5,153**	**5,025**
	% OF SYSTEM TOTAL	**68.6%**	**68.6%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2021 - DECEMBER 2021

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BAYSIDE 1		740	731
BAYSIDE 2		979	968
BAYSIDE 3		59	58
BAYSIDE 4		59	58
BAYSIDE 5		59	58
BAYSIDE 6		59	58
	BAYSIDE TOTAL	1,954	1,930
BIG BEND 1		0	0
BIG BEND 2		363	343
BIG BEND 3		368	348
BIG BEND 4		458	425
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,249	1,175
POLK 1		225	217
POLK 2		1,130	1,107
	POLK TOTAL	1,355	1,324
SOLAR		596	596
	SOLAR TOTAL	596	596
	SYSTEM TOTAL	**5,153**	**5,025**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2021 - DECEMBER 2021

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
POLK	2	6,778,150	33.31%	33.31%
BAYSIDE	1	4,749,080	23.34%	56.66%
BAYSIDE	2	4,741,650	23.31%	79.96%
SOLAR		1,567,130	7.70%	87.66%
BIG BEND	4	955,570	4.70%	92.36%
BIG BEND	3	579,130	2.85%	95.21%
POLK	1	562,040	2.76%	97.97%
BIG BEND	2	224,830	1.11%	99.08%
BAYSIDE	5	48,530	0.24%	99.31%
BAYSIDE	6	43,040	0.21%	99.53%
BAYSIDE	3	37,370	0.18%	99.71%
BAYSIDE	4	33,390	0.16%	99.87%
BIG BEND CT	4	25,860	0.13%	100.00%
BIG BEND	1	-	0.00%	100.00%
TOTAL GENERATION		20,345,770	100.00%	

GENERATION BY COAL UNITS:	955,570	MWH	GENERATION BY NATURAL GAS UNITS:	17,823,070	MWH
% GENERATION BY COAL UNITS:	4.70%		% GENERATION BY NATURAL GAS UNITS:	87.60%	
GENERATION BY SOLAR UNITS:	1,567,130	MWH	GENERATION BY GPIF UNITS:	17,786,490	MWH
% GENERATION BY SOLAR UNITS	7.70%		% GENERATION BY GPIF UNITS:	87.42%	

EXHIBIT TO THE TESTIMONY

OF

JEREMY B. CAIN

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2021 - DECEMBER 2021

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2021 - DECEMBER 2021

	Availability			Net
Unit	**EAF**	**POF**	**EUOF**	**Heat Rate**
Big Bend 4[1]	54.0	16.2	29.9	11,576
Polk 1[2]	77.7	7.7	14.6	9,684
Polk 2[3]	80.6	16.2	3.2	6,940
Bayside 1[4]	93.9	3.8	2.3	7,352
Bayside 2[5]	90.9	3.8	5.2	7,439

1 Original Sheet 8.401.20E, Page 12

2 Original Sheet 8.401.20E, Page 13

3 Original Sheet 8.401.20E, Page 14

4 Original Sheet 8.401.20E, Page 15

5 Original Sheet 8.401.20E, Page 16

DOCKET NO. 20200001-EI
2019 FINAL TRUE-UP FOR FUEL &
PURCHASED POWER AND CAPACITY
COST RECOVERY
EXHIBIT NO. _____ (JCH-1)

EXHIBIT TO THE TESTIMONY OF

JOHN C. HEISEY

OPTIMIZATION MECHANISM RESULTS

JANUARY 2019 - DECEMBER 2019

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 46
PARTY: TAMPA ELECTRIC COMPANY – DIRECT
DESCRIPTION: John C. Heisey JCH-1

TAMPA ELECTRIC
OPTIMIZATION MECHANISM
Actual for the Period: January 2019 through December 2019

TOTAL GAINS THRESHOLD SCHEDULE-Table 1

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Month	Wholesale Sales Total Gains ($)	Wholesale Purchases Total Savings ($)	Asset Optimization Gains ($)	Total Monthly Gains ($)	**Threshold 1** Gains ≤ $4.5 M ($)	**Threshold 2** $4.5M < Gains ≤ $8.0M ($)	**Threshold 3** Gains > $8.0 M ($)
				(2) + (3) + (4)			
January	30,782	182,546	29,915	243,243	243,243	-	-
February	12,277	14,988	38,741	66,006	66,006	-	-
March	13,038	714,487	68,565	796,090	796,090	-	-
April	27,731	249,015	42,679	319,425	319,425	-	-
May	194,775	478,506	48,011	721,292	721,292	-	-
June	158,620	411,318	33,812	603,750	603,750	-	-
July	80,113	893,762	106,200	1,080,075	1,080,075	-	-
August	92,347	718,660	62,762	873,769	670,119	203,650	-
September	165,191	750,225	20,790	936,206	-	936,206	-
October	669,603	(8,439)	21,662	682,826	-	682,826	-
November	42,627	21,573	47,123	111,323	-	111,323	-
December	11,582	1,657	20,789	34,028	-	34,028	-
Total	**1,498,686**	**4,428,298**	**541,049**	**6,468,033**	**4,500,000**	**1,968,033**	**-**

TOTAL GAINS SHARING SCHEDULE-Table 2

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Threshold 1	**Threshold 2**	**Threshold 2**	**Threshold 3**	**Threshold 3**	**Total**	**Total**
Month	Gains ≤ $4.5 M 100% Customer Benefit ($)	$4.5M < Gains ≤ $8.0M 40% Customer Benefit ($)	$4.5M < Gains ≤ $8.0M 60% TEC Benefit ($)	Gains > $8.0 M 50% Customer Benefit ($)	Gains > $8.0 M 50% TEC Benefit ($)	Customer Benefits ($)	TEC Benefits ($)
January	243,243	-	-	-	-	243,243	-
February	66,006	-	-	-	-	66,006	-
March	796,090	-	-	-	-	796,090	-
April	319,425	-	-	-	-	319,425	-
May	721,292	-	-	-	-	721,292	-
June	603,750	-	-	-	-	603,750	-
July	1,080,075	-	-	-	-	1,080,075	-
August	670,119	81,460	122,190	-	-	751,579	122,190
September	-	374,482	561,724	-	-	374,482	561,724
October	-	273,130	409,696	-	-	273,130	409,696
November	-	44,529	66,794	-	-	44,529	66,794
December	-	13,611	20,417	-	-	13,611	20,417
Total	**4,500,000**	**787,213**	**1,180,820**	**-**	**-**	**5,287,213**	**1,180,820**

TAMPA ELECTRIC
WHOLESALE POWER DETAIL
Actual for the Period: January 2019 through December 2019

Wholesale Sales-Table 3

(1)	(2)	(3)	(4)	(5)
Month	Wholesale Sales (MWh)	Wholesale Gross Gains ($)	Third Party Transmission Costs ($)	Total Net Wholesale Sales Gains ($)
				(3) + (4)
January	3,109	44,672	(13,890)	30,782
February	1,584	20,586	(8,309)	12,277
March	1,259	18,993	(5,955)	13,038
April	1,699	35,682	(7,951)	27,731
May	12,516	248,698	(53,923)	194,775
June	8,763	185,420	(26,800)	158,620
July	4,241	100,143	(20,030)	80,113
August	9,642	139,656	(47,309)	92,347
September	14,918	232,019	(66,828)	165,191
October	57,544	1,027,978	(358,375)	669,603
November	5,119	68,691	(26,064)	42,627
December	2,141	24,386	(12,804)	11,582
Total	**122,535**	**2,146,924**	**(648,238)**	**1,498,686**

Wholesale Purchases-Table 4

(1)	(2)	(3)	(4)	(5)
Month	Wholesale Purchases (MWh)	Wholesale Savings ($)	Capacity Purchases ($)	Total Net Wholesale Purchase Gains ($)
				(3) + (4)
January	1,850	182,546	-	182,546
February	3,585	14,988	-	14,988
March	28,257	714,487	-	714,487
April	9,040	249,015	-	249,015
May	31,740	478,506	-	478,506
June	181,001	411,318	-	411,318
July	187,687	893,762	-	893,762
August	183,457	718,660	-	718,660
September	178,395	750,225	-	750,225
October	180,130	(8,439)	-	(8,439)
November	8,789	21,573	-	21,573
December	595	1,657	-	1,657
Total	**994,526**	**4,428,298**	**-**	**4,428,298**

REDACTED

TAMPA ELECTRIC
ASSET OPTIMIZATION DETAIL-Table 5
Actual for the Period: January 2019 through December 2019

(1) Month	(2) Natural Gas Storage Optimization ($)	(3) Natural Gas AMA Gains ($)	(4) Resale of Solid Fuel ($)	(5) Total Asset Optimization Gains ($)
January	[redacted]	[redacted]	[redacted]	29,915
February	[redacted]	[redacted]	[redacted]	38,741
March	[redacted]	[redacted]	[redacted]	68,565
April	[redacted]	[redacted]	[redacted]	42,679
May	[redacted]	[redacted]	[redacted]	48,011
June	[redacted]	[redacted]	[redacted]	33,812
July	[redacted]	[redacted]	[redacted]	106,200
August	[redacted]	[redacted]	[redacted]	62,762
September	[redacted]	[redacted]	[redacted]	20,790
October	[redacted]	[redacted]	[redacted]	21,662
November	[redacted]	[redacted]	[redacted]	47,123
December	[redacted]	[redacted]	[redacted]	20,789
Total	**9,784**	**276,678**	**254,587**	**541,049**

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tallahassee District Office

Auditor's Report

Gulf Power Company
Hedging Activities

Twelve Months Ended July 31, 2020

Docket No. 20200001-EI
Audit Control No. 2020-013-1-1
August 24, 2020

Debra Dobiac
Audit Manager

Marisa N. Glover
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 47
PARTY: STAFF – DIRECT
DESCRIPTION: Debra M. Dobiac DMD-1

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Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the objectives set forth by the Division of Accounting and Finance in its audit service request dated January 13, 2020. We have applied these procedures to the attached schedules prepared by Gulf Power Company in support of its filing for hedging activities in Docket No. 20200001-EI.

The report is intended only for internal Commission use.

Objectives and Procedures

Definitions

GPC or Utility refers to Gulf Power Company.

Accounting Treatment

Objectives: The objective was to determine whether the accounting treatment for futures, options, and swap contracts between GPC and its counterparties is consistent with Commission Order No. PSC-2002-1484-FOF-EI, issued October 30, 2002, in Docket No. 20011605-EI, and as clarified by Order No. PSC-2008-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-2008-0667-PAA-EI, issued October 8, 2008, in Docket No. 20080001-EI.

Procedures: We obtained GPC's supporting detail of the hedging settlements for the twelve months ended July 31, 2020. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. Pursuant to the 2017 Stipulation and Settlement Agreement, the Utility did not enter into any new contracts between August 1, 2019 and July 31, 2020. GPC's hedge program was completed in the first quarter of 2020. No exceptions were noted.

Gains and Losses

Objectives: The objective was to determine whether the gains and losses associated with each financial hedging instrument that GPC implemented are in compliance with Commission Order Nos. PSC-2002-1484-FOF-EI, PSC-2008-0316-PAA-EI, and PSC-2008-0667-PAA-EI relating to hedging activities.

Procedures: We traced the monthly balances of all hedging transactions from GPC's Hedging Information Reports to its settlement report and its general ledger for the period August 1, 2019 to July 31, 2020. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the settlement statement details, and compared the price to the gas futures rates published by the NYMEX Henry Hub gas futures contract rates. We compared these recalculated gains and losses with GPC's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

Objectives: The objective was to determine whether the quantities of natural gas, residual oil, and purchased power are hedged within the limits (percentage range), as listed in the Utility's Risk Management Plan.

Procedures: We reviewed the quantity limits and authorizations. We also obtained GPC's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the twelve months ended July 31, 2020, and compared them with the Utility's 2016 Risk Management Plan. No exceptions were noted.

Separation of Duties

Objectives: The objectives were to review GPC's procedures for separating duties related to hedging activities for Front Office, Middle Office, and Back Office and internal and external audit reports or work papers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. We noted that the hedges currently in place for GPC were previously executed by Southern Company. As of January 1, 2019, all hedges were transferred to Next Era/FPL employees and they oversee the settling of those hedges. There were no internal or external audits specifically performed on the separation of duties related to hedging activities. No further work was performed.

Audit Findings

None

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Florida Power & Light Company's Responses to Staff's 2nd Set of Interrogatories No. 6.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 48
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Deaton

__QUESTION__:
Please refer to the Direct Testimony of FPL witness Deaton, page 12, lines 21-23, through page 13, lines 1-3, for the following request. Please state or identify the basis for including solar plant-related incremental security cost as a Fuel Cost Recovery Clause (FCRC) recoverable expense.

__RESPONSE__:
In Order No. PSC-01-2516-FOF-EI, issued in Docket No. 010001-EI on December 26, 2001, the Commission approved FPL's request to recover incremental power plant security costs related to the terrorist acts of September 11, 2001 through the fuel clause. In that order, the Commission states: "...we believe that this type of cost is a potentially volatile cost, making it appropriate for recovery through a cost recovery clause" and "We believe that approving recovery of this incremental power plant security cost through the fuel clause sends an appropriate message to Florida's investor-owned electric utilities that we encourage them to protect their generation assets in extraordinary, emergency conditions as currently exist." Through Order No. PSC-02-1761-FOF-EI issued in Docket No. 020001-EI on December 13, 2002, the Commission approved the recovery of incremental power plant security costs through the capacity clause in order to allocate the costs among the rate classes on a demand basis, which is consistent with base rate treatment of similar costs.

The solar-related incremental security costs included for recovery in FPL's 2020 Capacity clause Actual/Estimated True-Up filing are associated with FPL's solar plants, in compliance with North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) requirements. Costs associated with FPL's DeSoto, Space Coast and Martin solar plants, which are recoverable through the Environmental Cost Recovery Clause, are not included in these costs.

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Florida Power & Light Company’s Responses to Staff’s 3rd Set of Interrogatories No. 8.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 49
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Coffey

<u>QUESTION</u>:
Please refer to the Direct Testimony of Florida Power & Light (FPL) witness Robert Coffey, filed with FPL's Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery Factors for January through December 2021 (Petition), page 4, line 22, through page 5, lines 1-5 for the following requests.

a. Please identify, if any, the replacement power costs associated with the March 2020 return-to-service delay at the St. Lucie Nuclear Power Plant, Unit No. 2.
b. If applicable given the response to (a.), please discuss why the Company believes such replacement power costs are appropriate for recovery through the Fuel Cost Recovery Clause.

<u>RESPONSE</u>:
a. $383,078. Please see Attachment I to this Interrogatory.

b. The Commission has consistently based clause recovery of replacement fuel costs on whether a utility's actions were prudent in the circumstances that led to the need for replacement power. FPL's actions associated with the March 2020 return-to-service delay were prudent. During the Spring 2020 outage, FPL performed a planned replacement of a 6900 volt electrical switchgear required for plant operation. An interfacing equipment configuration conflict was discovered during project implementation. Additional work scope and increased implementation duration was required to address the discovered condition. FPL provided all relevant information to the vendor responsible for the engineering and outage installation of the new switchgear equipment. FPL was aware that a portion of this information was not verifiable during plant operation because of industrial safety risks associated with accessing certain areas of an operating power plant. Recognizing outage schedule risk existed from the unverifiable design assumptions or configuration documentation, FPL planned an inspection of interfacing equipment that is inaccessible during plant operation at the earliest opportunity in the outage. The inspection identified a discrepancy between vendor design assumptions and actual plant configuration requiring resolution to complete the new equipment installation. As a contingency prior to the outage, FPL procured and received all necessary materials to correct the identified configuration discrepancy. However, the duration required to correct the configuration discrepancy was not accounted for in the original outage schedule. Because of accessibility limits during plant operation, the additional outage duration would have been required even in the case that the configuration discrepancy was known prior to the start of the outage. The replacement fuel costs resulting from the return to service delay at St. Lucie Unit 2 were prudently incurred to provide electric service to its customers, and therefore should be recovered through the fuel cost recovery clause.

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Florida Power & Light Company's 2019 Response to Staff 5th set of Interrogatories No. 41.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 50
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Coffey

<u>QUESTION</u>:
For the purpose of Interrogatory Numbers 41-42 and subparts, please refer to Original Sheet Number 6.202.021 of Florida Power & Light Company's GPIF Actual Unit Performance Data Schedule for April 2019, filed on May 20, 2019 (April Performance Report). Please answer the following:

The April Performance Report identifies that a full forced outage began at St. Lucie Unit 1 on April 25, 2019 ("Outage").

A. Please describe the "UEL Main Generator Ground Fault" that is referenced on Original Sheet Number 6.202.021 of the April Performance Report.
B. In easily understandable terms, please describe this Outage event, and the restoration work performed in order to return St. Lucie Unit 1 to full commercial service.
C. Please identify the date St. Lucie Unit 1 returned to service from this Outage event.
D. Please identify the total number of hours St. Lucie Unit 1 was unavailable due to this Outage event.
E. Please identify the Net Summer Capacity (NSC) for St. Lucie Unit 1.
F. Please describe the actions FPL took to serve its customers while this base load plant was not operating.
G. Please state the replacement power cost attributable to this Outage, and explain how this amount was calculated.
H. How did FPL recover the replacement power cost attributable to this Outage?
I. Please state the repair cost attributable to this Outage.
J. How will FPL recover the repair cost attributable to this Outage?

<u>RESPONSE</u>:

A. The unplanned energy loss (UEL) was a full forced outage that began on April 25, 2019 at 09:18 AM until the main generator was restored and placed back in service on June 21, 2019 at 01:11 AM. The duration was approximately 57 days.

   The event was initiated by a main generator ground fault. The ground fault activated protective circuits that automatically shut down the nuclear reactor and electrically isolated the main generator.

   The main generator could not be returned to service until all repairs were completed.

B. The outage activities began with electrical testing to identify the extent of main generator damage caused by the ground fault. The location of the damage was determined to be in the stator windings. Subsequent troubleshooting required the removal of the main generator rotor and disassembly of the stator. The repair required a full rewind of the generator. The repair took 49 days to complete which is a vendor record for the shortest ever unplanned generator rewind.

C. St. Lucie Unit 1 returned to service on June 21st at 01:11 AM.

D. St. Lucie Unit 1 was unavailable due to this outage event for approximately 1,360 hours. Power ascension to return to 100% power was approximately 34 hours.

E. St. Lucie Unit 1 Net Summer Capacity (NSC) is 981 MW.

F. While St. Lucie Unit 1 was not operating, FPL served its customers by utilizing available generation from the balance of its fleet. Additionally, as part of its normal day-to-day activities, FPL actively pursued and executed power purchases in the wholesale power market when market prices were lower than the cost of FPL's own generation.

G. Please see Attachment 1 to this Interrogatory.

H. FPL has not yet recovered the replacement power costs associated with this outage event. The replacement power costs are included in actual fuel costs for 2019 and will be recovered through FPL's fuel cost recovery clause factor to be effective commencing January 1, 2020.

I. The repair cost attributable to this outage was approximately $29 million.

J. Inspection and repair costs will be recovered through FPL's base rates.

Event Start	Event End	Seq. #	Event Title	MW Loss	Outage Hours	MWh Loss	Replacement Cost ($/MWh)	Replacement Cost ($)	SL1 Fuel Cost ($/MWh)	Nuclear Fuel Cost ($)	Net Replacement Cost ($)
4/25/2019 9:18	5/1/2019 0:00	1	U1 UEL Main Generator Ground Fault	981.00	134.70	132,141	$19.93	$2,633,304	$5.40	$714,188	$1,919,117
5/1/2019 0:00	6/1/2019 0:00	2		981.00	744.00	729,864	$19.25	$14,047,035	$5.40	$3,944,733	$10,102,302
6/1/2019 0:00	6/21/2019 1:11	3		981.00	481.18	472,041	$18.52	$8,739,971	$5.40	$2,551,263	$6,188,708
6/21/2019 1:11	6/22/2019 11:30	4	Power Ascension	336.72	34.32	11,555	$18.52	$213,946	$5.40	$62,452	$151,494
				Total	**1,394.20**	**1,345,600.66**		**$25,634,257**		**$7,272,636**	**$18,361,621**
											$316,080 /Day

April 2019 - A4 Data	
SL1 Fuel Cost	**SL1 Heat Rate**
0.52	10,357
SL1 $/MWh	
$5.405	

April 2019 - A3 Data								
Fuel	**MWh**	**% Mix**	**Fuel Cost $**	**$/MWh**	**Demand $**	**Rev. Fuel Cost $**	**$/MWh**	**WA $/MWh**
Heavy Oil	15,428	0.20%	$1,968,602	$127.60	$0	$1,968,602	$127.60	$0.26
Light Oil	6,830	0.09%	$1,001,213	$146.59	$0	$1,001,213	$146.59	$0.13
Coal	186,421	2.45%	$5,444,667	$29.21	$0	$5,444,667	$29.21	$0.72
Gas	7,405,223	97.26%	$219,361,512	$29.62	$76,045,902	$143,315,610	$19.35	$18.82
Total	**7,613,902**	**100.00%**	**$227,775,994**		**$76,045,902**	**$151,730,092**		**$19.93**

May 2019 - A3 Data								
Fuel	**MWh**	**% Mix**	**Fuel Cost $**	**$/MWh**	**Demand $**	**Rev. Fuel Cost $**	**$/MWh**	**WA $/MWh**
Heavy Oil	26,474	0.29%	$3,299,209	$124.62	$0	$3,299,209	$124.62	$0.36
Light Oil	7,266	0.08%	$899,256	$123.76	$0	$899,256	$123.76	$0.10
Coal	268,083	2.90%	$7,705,798	$28.74	$0	$7,705,798	$28.74	$0.83
Gas	8,939,365	96.73%	$243,296,912	$27.22	$77,344,351	$165,952,561	$18.56	$17.96
Total	**9,241,188**	**100.00%**	**$255,201,176**		**$77,344,351**	**$177,856,825**		**$19.25**

June 2019 - A3 Data								
Fuel	**MWh**	**% Mix**	**Fuel Cost $**	**$/MWh**	**Demand $**	**Rev. Fuel Cost $**	**$/MWh**	**WA $/MWh**
Heavy Oil	27,792	0.30%	$3,540,260	$127.38	$0	$3,540,260	$127.38	$0.38
Light Oil	9,113	0.10%	$1,283,074	$140.79	$0	$1,283,074	$140.79	$0.14
Coal	221,108	2.37%	$6,765,450	$30.60	$0	$6,765,450	$30.60	$0.72
Gas	9,086,126	97.24%	$237,476,593	$26.14	$76,055,970	$161,420,623	$17.77	$17.28
Total	**9,344,139**	**100.00%**	**$249,065,376**		**$76,055,970**	**$173,009,406**		**$18.52**

51

Florida Power & Light Company's 2019 Response to Staff 2nd Production of Documents No. 3.

Including additional files for No. 3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 51
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Coffey

<u>QUESTION</u>:
Please produce any root cause analysis reports, technical documents, and/or technical presentations that pertain to the outage identified in Staff's 5th Set of Interrogatories.

<u>RESPONSE:</u>
Please see files provided
"L-2019-128 U1 Turbine Ground"
"Plant St Lucie Unit 1 Rx Trip 4-25-2019 NRC Notification EN54027"
"RCE 2312208-01 MRC 6-4-19 Approval"
"PSL 1 Ground Fault Rev 4"

Documents responsive to this request are provided as Bates Nos. FCR-19-00025 through FCR-19-00111.

52

Tampa Electric Company's answers to Staff's Second Set of Interrogatories, No. 5.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 52
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Sizemore

5. Please refer to Tampa Electric Company's (TECO or Company) Direct Testimony and Exhibit (MAS-3) of witness M. Ashley Sizemore, filed with the Fuel and Purchase Power Cost recovery and Capacity Cost Recovery January 2021 through December 2021, Projection petition (Projection Petition), and the Prepared Direct Testimony and Exhibit of Jeffrey S. Chronister, filed with TECO's Petition for Limited Proceeding to True-up First and Second SoBRAs (SoBRA T/U Petition) for the following request. Regarding the true-up associated with the Company's First and Second SoBRA, in his testimony filed with the SoBRA T/U Petition, page 12, witness Chronister testifies: "the remaining net true-up amount to be applied in the calculation of the 2021 capacity factors is a credit of $239,712." Please explain how the Company applied the remaining net true-up in the calculation of the 2021 capacity factors while also citing to any relevant journal entries contained in Witness Sizemore's testimony filed with the Projection Petition.

A. In witness Chronister's Prepared Direct Testimony, filed on April 30, 2020, it was estimated that the Commission Order associated with Docket No. 20200144-EI, Petition to True-up First and Second SoBRAs, by Tampa Electric Company, would be issued prior to the submittal of Tampa Electric's 2021 Capacity Projection, filed on September 3, 2020. However, Commission Order No. PSC-2020-0303-PAA-EI was not issued until September 4, 2020, and the company did not include the final true-up amount of $239,712 in its 2021 projection filing. M. Ashley Sizemore's Prepared Direct Testimony for the 2020 Capacity Actual/Estimate filing, filed on July 27, 2020, Page 9, states that the "adjustment required will be made upon resolution of Docket No. 20200144-EI." Now that the docket matters have been reviewed and the final true-up amount has been approved by the Commission, the $239,712 will be included in the September 2020 closing of the books and will be reported in the 2020 Actual Capacity True-up to be submitted in March 2021.

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Ashley Sizemore who deposed and said that she is Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (No. 5) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 2nd day of October, 2020.

A. Ashley Sizemore
____

Sworn to and subscribed before me this 2ND day of October, 2020.

____

NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Tison C Vega
My Commission GG 950315
Expires 02/01/2024

My Commission expires ____________________

EXHIBIT NOT ENTERED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 53
PARTY: OPC
DESCRIPTION: Coffey

Exhibit No.: 8

Proffered by: Public Counsel

Short title: FPL RCE - Public Version

Witness(s): FPL- COFFEY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 54
PARTY: OPC
DESCRIPTION: Coffey

St. Lucie Station

Unit 1 Main Generator Ground Fault
Root Cause Evaluation Report

Event Date: 04/25/2019

CR Number: 02312208

Root Cause Team	Name	Dept/Group
Management Sponsor	Mark Jones	Engineering Director
Team Leader	Anas Bouchfaa	Engineering
RC Evaluator	Gary Arntson	Engineering
Team Members	Don Zoll	Maintenance
	Andy Terezakis	Operations

Root Cause Evaluator: GARY ARNTSON / Gary Arntson **Date:** 8/19/19
Print/Sign

Management Sponsor: MARK JONES / Mark Jones **Date:** 8-19-19
Print/Sign

MRC Chair: Dan DeBoer / Dan DeBoer **Date:** 8/19/19
Print/Sign

Electronic Signature may be obtained by assigning actions in NAMS.
Refer to PI-AA-104-1000 for details.

The root cause process is designed to be self critical to drive improvement. As such, specific organizational and/or programmatic causes within the plant's span of control are identified. The root cause process determines a functional cause and not a legal or contractual cause.

1.0 Executive Summary

On 04/25/2019 St Lucie Unit 1 tripped due to a generator lockout during performance of a Reactive Power Lagging Capability Test. The lockout was initiated due to a ground fault in the generator. The fault condition was verified using electrical testing and determined to be in the C phase winding of the stator; however, the location could not be identified during less-intrusive inspections. After generator disassembly and rotor removal, the fault was located using electrical testing to a specific half-coil stator bar in the bottom of slot 17 (B17) in the stator. A decision was made to perform a generator rewind to address the fault.

The ground fault has been attributed to a small puncture through the ground wall insulation of stator bar B17. It has been demonstrated that a latent initiator for the failure was introduced in the stator during a 2012 generator rewind; the puncture developing through the insulation over the course of seven years. Examination and lab analysis has been performed on stator bar B17, however the specific failure mechanism could not be established definitively. Consequently the initiating occurrence in 2012, and its underlying cause, is indeterminate.

An extent of condition review of Unit 2 generator maintenance history has been completed. The Unit 2 generator completed high potential testing in September 2018 and the insulation successfully withstood the high potential test voltage. It can be concluded that a similar ground fault was not present and is not likely in the near term.

Causes

A small puncture developed through the ground wall insulation of stator bar B17 in the phase C Stator Winding resulting in a fault current path to ground.

The root cause of the puncture is indeterminate.

Corrective Action

Complete rewind of the Unit 1 generator to restore stator winding to serviceable condition.

2.0 Report

1. Event Description

On 04/25/2019 St Lucie Unit 1 Operators commenced performance of a Reactive Power Lagging Capability Test in accordance with procedure 0-OSP-53.01. Pre-requisite and risk mitigation activities for the test were completed including verification of generator H2 gas pressures, pre-test predictive maintenance checks, cooling water system performance reviews, securing all load threat work activities both in the plant and switchyard, staging personnel for monitoring exciter fuses and generator vibrations during the test, and establishing pre-planned operating conditions in accordance with St Lucie Unit 2 and Transmission System Operations (TSO).

At 0819 Unit 1 began reactive power ascension. At 0835 the Unit 1 generator reached the test reactive power of 255MVAR out and began a 1 hour hold as specified in the test procedure. Operators began manual logging of test data on 15 minute intervals with no abnormal indications. At 0918 the generator backup lockout was tripped. An automatic turbine and reactor trip occurred in response to the lockout as expected.

Initial investigations determined that the lockout was initiated by operation of backup ground protection relay 64GB/881. The relay's protection zone includes the Main Generator, Isolated Phase bus and associated potential transformers, the high voltage side of Main Transformers 1A and 1B, and the high voltage side of Aux Transformers 1A and 1B. A failure investigation team was chartered in accordance with EN-AA-108-1001 to investigate the ground fault. Digital Fault Recorder data captured for the event provided evidence that a valid ground fault condition was present and likely located on the C phase. After removal of generator flexible links to separate the generator from the isolated phase bus, and separation of each phase at the neutral bus, a ground was confirmed internal to the generator on phase C. Subsequent disassembly and testing confirmed the bottom stator bar in slot 17 of the generator (B17) had a low resistance ground.

2. Problem Statement

The Unit 1 Main Generator experienced a ground fault during performance of a reactive power lagging capability test. The ground fault resulted in a generator lockout and reactor trip.

3. Analysis

A. Background Information on Unit 1 Generator

The St Lucie Unit 1 Main Generator is an 1800rpm direct hydrogen inner-cooled synchronous unit originally supplied by the Westinghouse Electric Company with a rating 1000MVA. During the SL1-24 outage various modifications were performed by Siemens Energy, the current OEM, to achieve increased output for the Extended Power Uprate project. These modifications included rotor replacement and stator rewind to increase the rating from 1000MVA to 1200MVA [D19,D21,D22].

The 'stator' is the primary stationary component of the generator consisting of a stator core, three phase windings, and the generator leads which conduct the electrical power from the stator windings. Several images of the Unit 1 generator during rewind in SL1-24 are presented on the following pages to illustrate the stator construction. The core is constructed using laminations of steel with slots to receive the stator coils (Figure 1). The windings each consist of a series of distributed single turn coils. The coils are constructed using half coil 'stator bars' installed within slots in the core (Figure 2 and 3) and connected at the ends of the stator outside of the core (Figure 4).

Each stator bar contains conductor, hydrogen cooling tubes, and several layers of materials forming the insulation system (Figure 5 and 6). The conductor consists of copper strands that are individually insulated from each other to reduce losses and arranged close to the cooling tubes for heat removal. The ground wall insulation is 'Thermalastic'; a trademarked insulation system originally developed by Westinghouse consisting of layers of inorganic mica tape impregnated with an organic epoxy resin.

Special conductive and semi-conductive layers are applied to protect the ground wall insulation from partial discharges (sometimes termed corona) which are damaging to the organic components of the insulation. The Inside Corona Protection (ICP) is applied around the conductor strands under the ground wall. The ICP layer incorporates a conductive copper strip connected to a strand at one end of the stator bar to provide a drain for excess electrical charge. The Outside Corona Protection (OCP) layer is applied over the ground wall insulation within the stator slot and extends for a short distance outside of the slot on both ends. The OCP is maintained in contact with the grounded core laminations to provide a drain path for excess electrical charge outside the ground wall. The OCP layer is terminated at each end of the bar outside of the slot with a semi-conductive End Corona Protection (ECP) layer, also referred to as gradient taping, used to control electrical stress at the OCP termination.

Figure 1 – Stator Core prior to Coil Installation

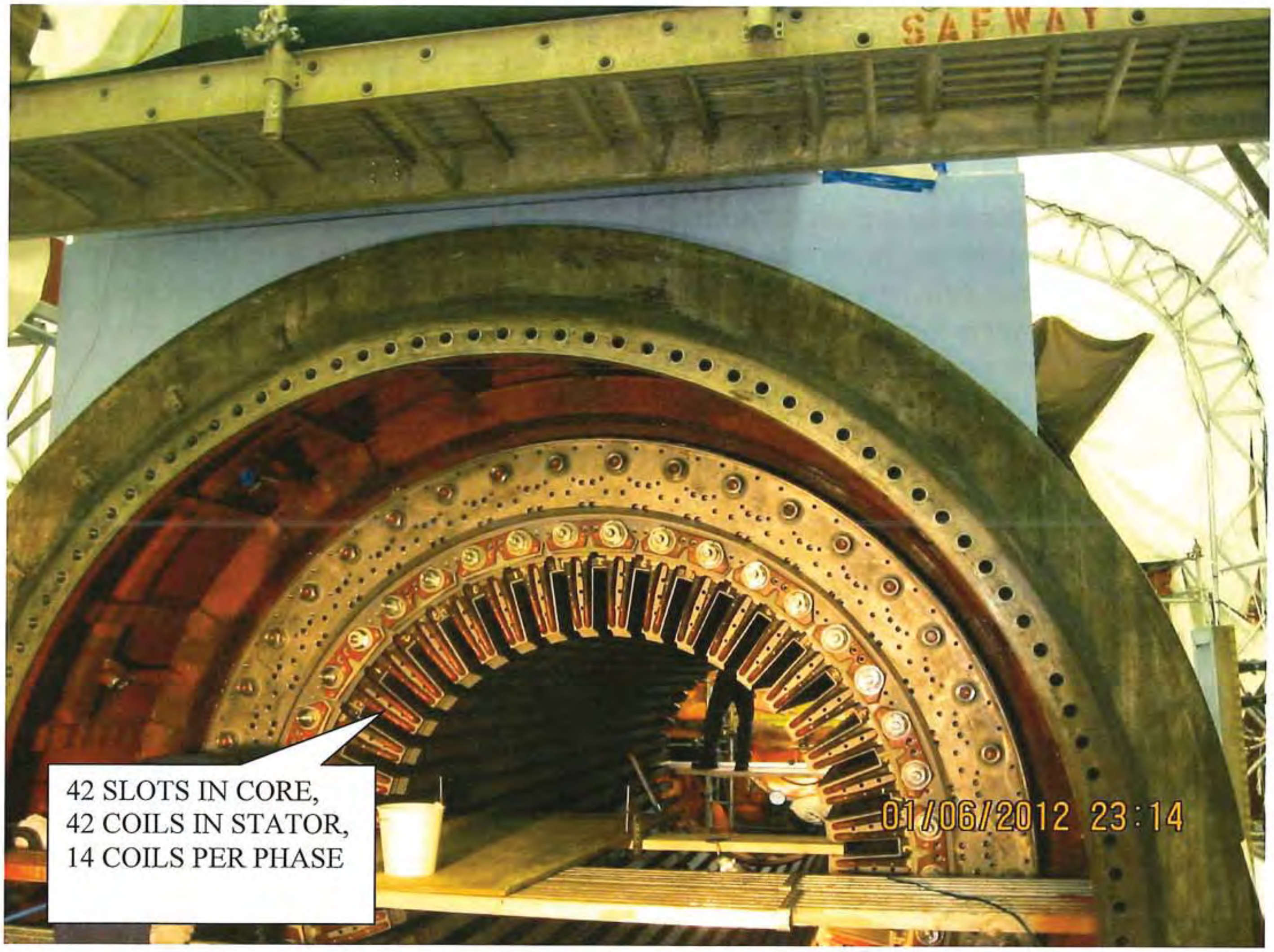


Figure 2 – Bottom Half-Coil installation

Figure 3 – Top Half-Coil Installation

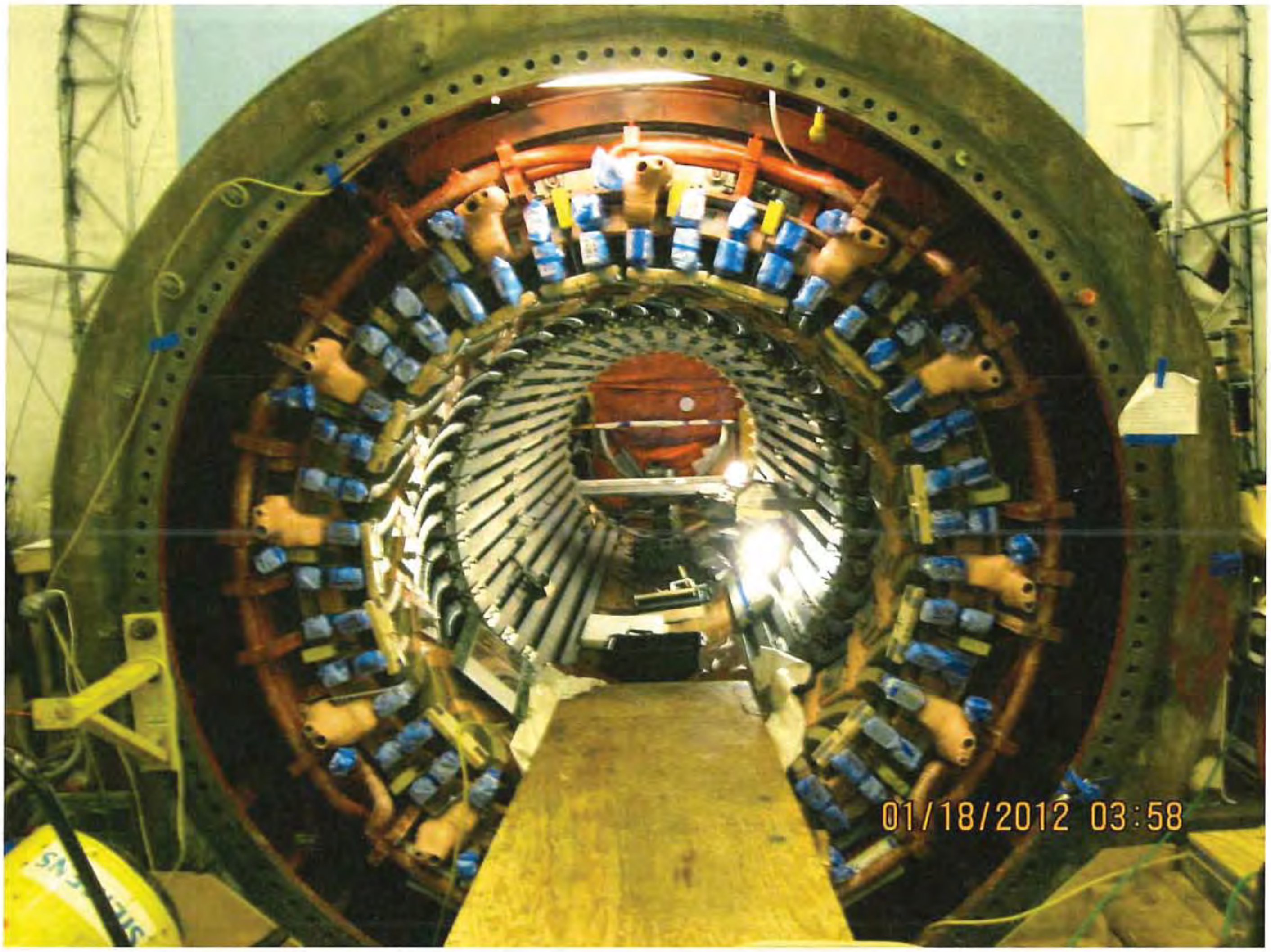


Figure 4 – Coil End Connections

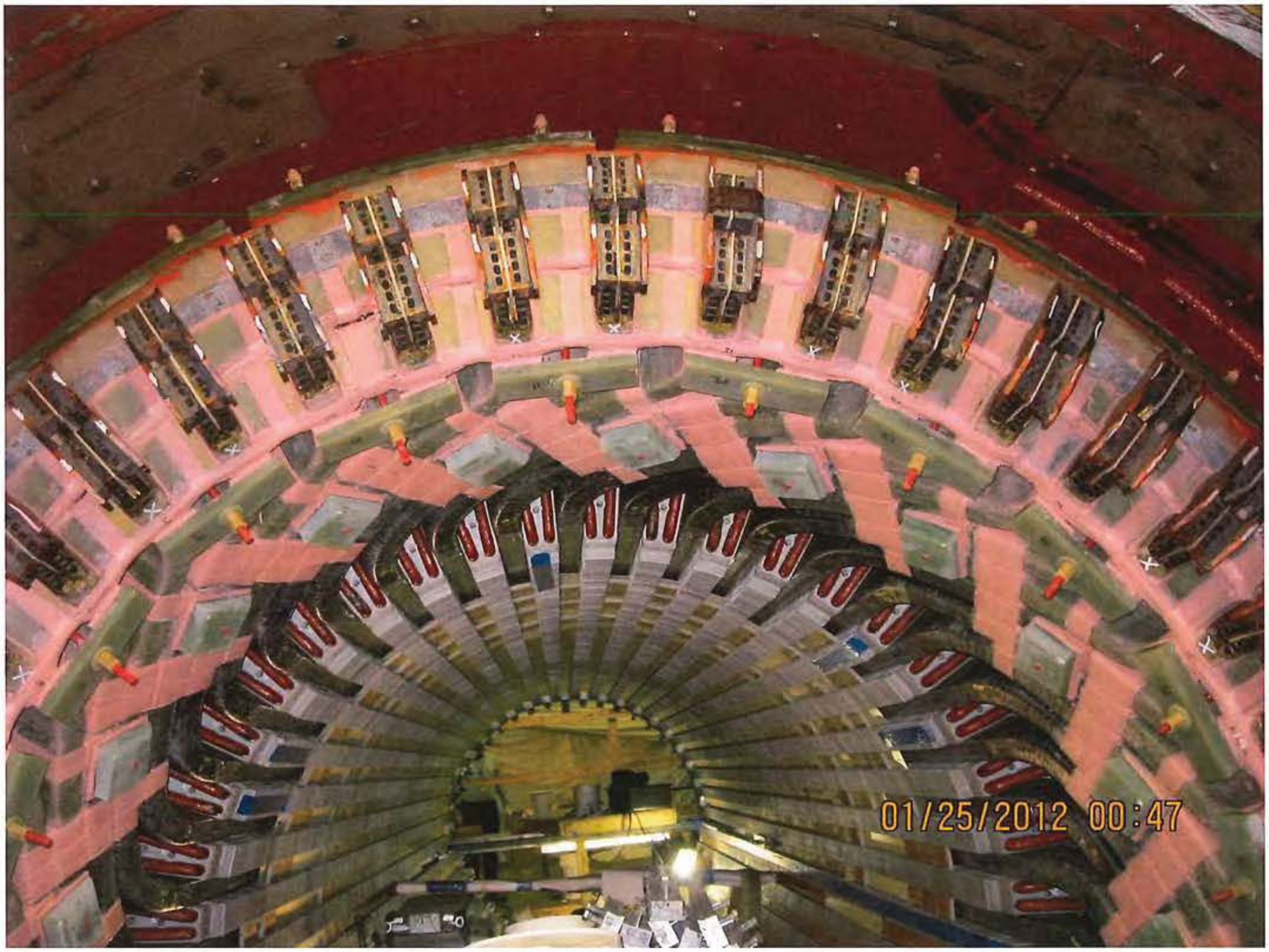


Figure 5 – Stator Bar Section

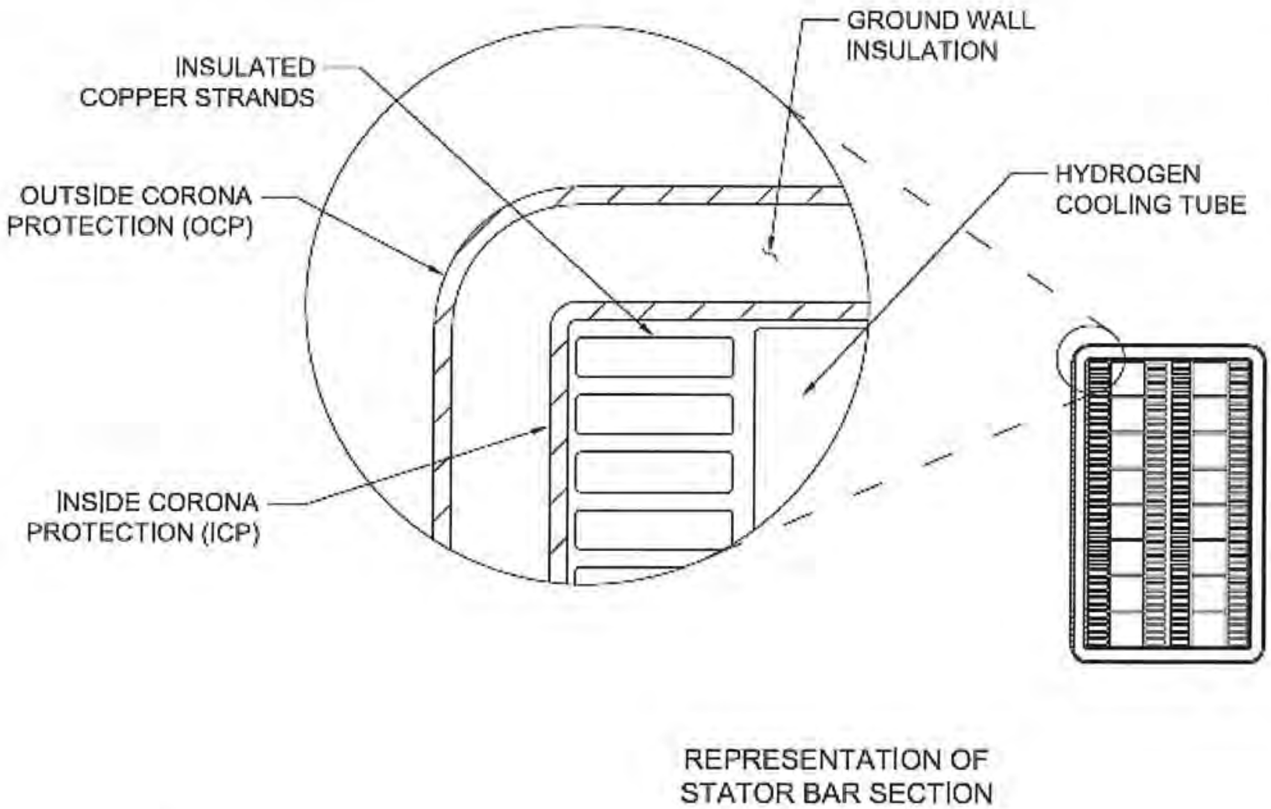


Figure 6 – Section of Stator Bar Removed from Unit 1 Generator 2019 Rewind

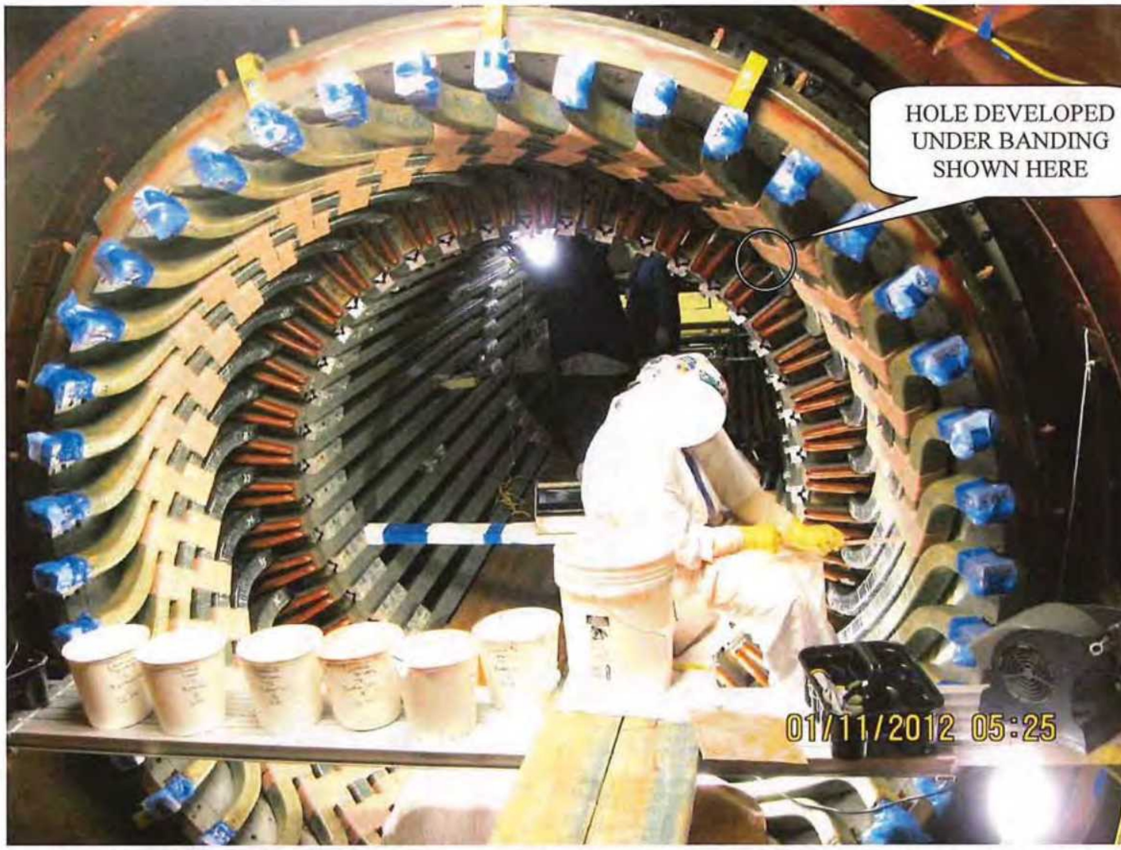
B. Fault Tree Analysis and Support Refute Matrix

The Fault Tree presented in Attachment B was developed to investigate a range of possible causes for insulation failure. The fault tree reflects input from relevant EPRI and IEEE publications on rotating electrical machines and their insulation systems [D16,D17,D20]. Evidence supporting or refuting each failure was captured in the Support Refute Matrix presented in Attachment C.

Examination of the fault current track and the insulation breach demonstrates that the fault was caused by a small puncture through the insulation. This small puncture is located on the turbine end outside of the stator slot and underneath a layer of structural banding material at the first diamond spacer. Available data is insufficient to determine a singular cause for the presence of this puncture; three possible causes hypothesized under the fault tree were neither refuted nor adequately supported:

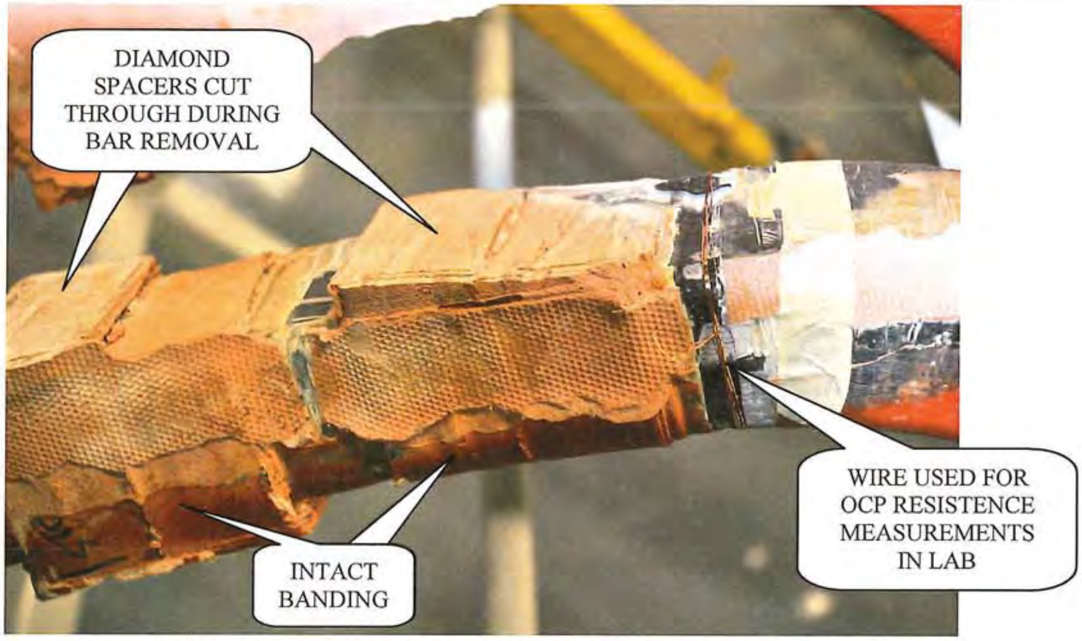
- Ferromagnetic particle introduced during installation of the stator bar
- Impact damage during handling, or installation of the stator bar
- A contaminant or small object introduced in the stator bar insulation during its manufacture or construction

The small puncture in the insulation was located under banding material that was found intact and had been in place since the stator rewind in 2012. Therefore, all of these possible causes involve some occurrence prior to completion of the stator rewind in 2012. The stator was qualified with a high potential test after the rewind was completed. The unit subsequently operated for over 7 years.

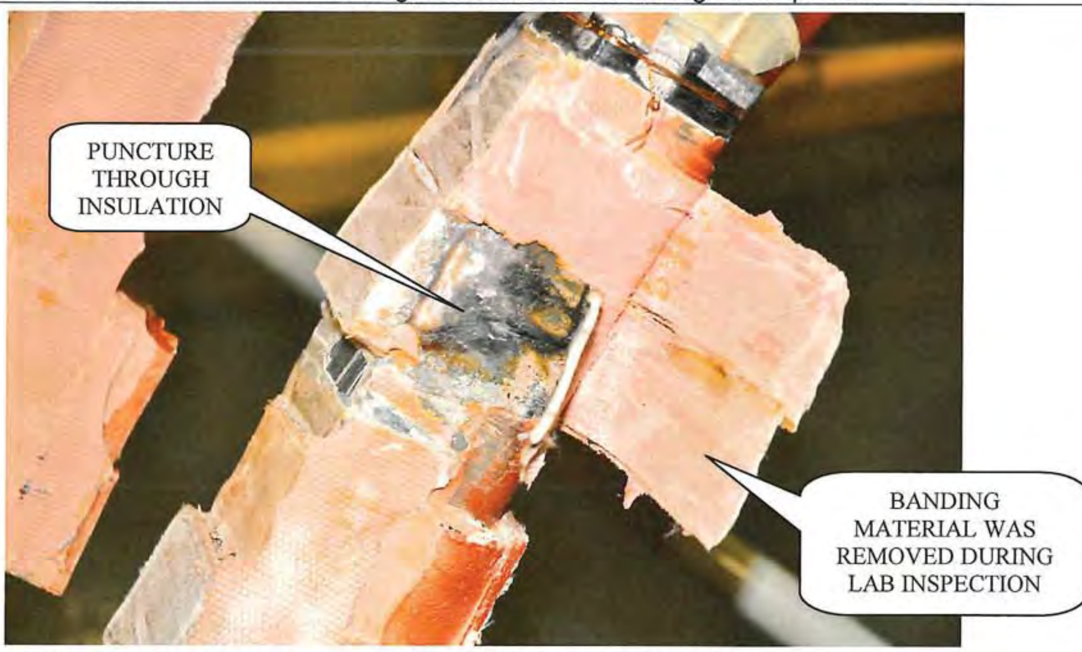


Jan. 2012 - Wet Tie Banding of Bottom Bars at Turbine end of St Lucie Unit 1 Generator.

May 2019 – Removal of Top Bar in Slot 17.



June 2019 – Intact banding material over B17 during lab inspection.



June 2019 – Small puncture through insulation of B17 located during lab inspection.

C. Event and Causal Factors Analysis

The Event and Causal Factors Chart is presented in Attachment D. The chart includes documented history of the Unit 1 main generator since the generator rewind completed in 2012 for Extended Power Uprate (EPU), refueling outage SL1-24.

All of the possible causes that have not been refuted on the Fault Tree analysis involve some initiating occurrence prior to completion of the stator rewind in 2012. All of these involve in some manner the manufacture and assembly services procured for the EPU project. A specific causal factor(s) within the manufacture and/or assembly processes of service providers in 2012 remains indeterminate.

In 2013 a temperature instrument replacement activity was completed during refueling outage SL1-25. This activity is unrelated to the April 2019 ground fault; however, it involved more than routine maintenance and testing. A High Potential Test of the generator was completed after reassembly in SL1-25 with satisfactory results.

No other significant generator maintenance activities have been performed since the rewind in 2012. Routine crawl through inspections were performed in 2015, 2016, 2018 outages. During the SL1-27 outage in 2016 a ground condition was measured during insulation resistance testing; this was caused by water intrusion in the neutral ground transformer bushing and is unrelated to the April 2019 ground fault. [D28,D29].

4. Causal Factor Categorization

A. Address each category - People, Programmatic, Organizational and Equipment based on the analysis.

Equipment:

Sufficient evidence has been provided to demonstrate that the generator ground resulted from a small puncture through the ground wall insulation on the turbine end of stator bar B17 in the phase C stator winding.

There are three potential causes for the equipment failure which could not be refuted (ferromagnetic particle, impact damage, contaminant in insulation). It has been demonstrated that the initiating occurrence for producing this puncture happened before completion of the generator rewind for EPU in 2012. However, the failure mechanism that resulted in a puncture of the ground wall insulation is indeterminate.

The ground fault occurred coincident with the performance of a Reactive Power Lagging Capability Test. This test is one of several tests designed to demonstrate the St Lucie Plant generators can reliably achieve specified values of reactive power used for operation, maintenance, planning and modeling for the bulk electric system. The generator was operated at 255MVAR lagging for the test which produced a modest increase in voltage from 22kV nominal to 22.7kV. The generator was maintained below its operating limits of 23.1kV for voltage and 510MVAR reactive power capability.

The occurrence of the fault provides no indication that the stated generator capability is unreliable. No deficiencies in operation, maintenance, specification or design of the St Lucie Unit 1 generator, or its excitation equipment, were noted. Rather, the mechanism producing a singular small puncture in the insulation of stator bar B17 slowly degraded the insulation capability over the course of 7 years in service. The condition was sufficiently degraded to a point of marginal performance such that the small additional voltage stress during performance of the test exceeded the remaining insulation capability.

People:

It remains unclear if any legacy task performance error, during manufacture and/or assembly of the generator, played a role in initiating a puncture in the insulation. Therefore analysis of human performance causal factors relating to the ground fault is not possible.

Coincidence of the generator lockout to the performance of a Reactive Power Lagging Capability Test was reviewed. No operator error was found to play a role in the ground fault. Additionally, there is no evidence that human intervention during performance of the test was possible to prevent, mitigate, or minimize the effects from the ground fault. Though the generator is provided with various diagnostic instruments, there were no alarms or abnormal indications noted leading up to generator lockout. Continuous monitoring of the generator by operations and maintenance staff provided no leading indication of a problem.

Organizational and Programmatic:

The failure mechanism that resulted in a puncture of the ground wall insulation is indeterminate; therefore any underlying organizational and programmatic causal factors remain unclear.

The possible causal factors that underlie each of three possible failure mechanisms are unique. The only clear commonalities between these failures are that 1) the causal factor was present prior to completion of the 2012 stator rewind, and 2) the causal factor generally involves manufacture and assembly of the generator stator.

Basic expectations for packaging, handling, cleanliness, foreign material exclusion, inspection and testing requirements, etc. applicable for performing the generator manufacture and assembly service activities were established in the project specification. Responsibility for implementation was assumed contractually by providers performing such activities (Siemens and its subcontractors) under the providers' processes and procedures, which are not within the scope of the plant.

The organizational interface between the station and Siemens was reviewed to the extent practicable. Contract requirements for Quality Assurance were imposed in accordance with industry standard. These included expectations for inspection, testing, packaging, shipping, non-conformance process, customer communication and facilities access for mutually agreed upon witness points. An FPL project team was established for coordination and oversight of turbine and generator activities under the EPU project. The project team implemented oversight activities including tracking project milestones, review of deliverables and witness/inspection activities. No direct relation to any of the three potential causal factors was noted. Due to the latent nature of the condition, and the inability to identify it with testing, it can be concluded that external oversight could not have reasonably prevented the generator stator ground.

Siemens produced a customer report for the generator rewind and core replacement which summarized the onsite work activities. The specific Siemens processes used in the performance of the onsite activities are proprietary; therefore investigation beyond what is available in the customer report and plant records is outside the scope of this analysis. Siemens is performing its own internal root cause analysis in parallel with this effort.

Whichever specific initiating condition occurred, it was not detected during the generator assembly activities. The customer report includes descriptions for the activities completed, and lists deficiencies, issues, questions etc. (identified as PCM Clarifications/WRITs/CAPAs) encountered in the field and how these were addressed. Review of the customer report provides no indication of any assembly problems affecting stator bar B17. Instances of stator bar damage identified in the field were noted. A request for clarification from Siemens on these specific issues was satisfied and it was shown that they did not involve either B17 or adjacent stator bars. The damage was attributed to installation activities and repaired. No issues of cleanliness, foreign/native materials or contamination were noted. Generator testing during and after assembly was in accordance with industry standards and manufacturer recommendations. Testing was completed with satisfactory results and St Lucie Unit 1 was placed in service in April 2012. While the identification of damage to certain stator bars during installation is of note, there is no information provided in the customer report attributable to any initiating condition of insulation failure in stator bar 17.

The condition remained undetected for 7 years until it was self-revealed when the generator ground fault occurred in April 2019. During this time the manufacturer's routine maintenance recommendations were performed approximately every 18 months during refueling outages. This maintenance, including crawl through inspection, was performed by Siemens. The crawl through scope includes inspection of turbine end turn blocking and banding, and was found in satisfactory condition during each inspection. These inspections had no opportunity for finding the developing puncture through stator bar B17 due to its location on a bottom bar and underneath banding. In addition, supplemental work was performed in 2013 to repair generator Resistance Temperature Detectors (RTDs). This work included a maintenance high potential test of the stator, which was completed with satisfactory results. It can only be concluded that the developing puncture through stator bar B17 had not sufficiently damaged the insulation after approximately 18 months in service to have been revealed from this test. The manufacturer also recommends major maintenance scope including rotor out inspection and high potential testing at approximately 7 year intervals. This major maintenance scope was scheduled for implementation in September 2019 during the SL1-29 refueling outage.

The maintenance and testing program for the Unit 1 generator was in accordance with industry practice and the manufacturer's recommendations. Due to the nature of the developing puncture and its location, detection by either routine maintenance inspections or testing was very unlikely. Even after the fault, its location was not apparent from any field inspections performed onsite prior to disassembly and rewind activities. Hypothetically, had the fault not occurred in April, it can be reasonably concluded that the winding would have failed during high potential testing in the SL1-29 outage.

B. Based upon the above documentation, categorize the results using the Causal Factor Characterization Matrix below.

The Unit 1 main generator stator ground fault was the result of a small puncture through the ground wall insulation of stator bar B17. The puncture hole was located underneath banding that was found intact. Several possible fault mechanisms which could have produced the hole were identified. The specific mechanism could not be proved as there is insufficient factual evidence to do so. The nature of these possible failure mechanisms is such that the causal factor lies within the manufacture and/or assembly processes for the stator. The causal factor is outside of the scope of the station; no gaps in station processes or external oversight were identified. The root cause is indeterminate.

Causal Factor Characterization (Each causal factor identified is listed and classified in the appropriate People, Programmatic, Organizational and Equipment categories.)		
Cause Type	**Cause Statement**	**Category**
Direct Cause	A small puncture developed through the ground wall insulation of stator bar B17 in the phase C Stator Winding resulting in a fault current path to ground.	Equipment
Root Cause	Indeterminate*	Indeterminate

*In accordance with PI-AA-100-1005:

"If the lack of cause identification is beyond the scope of the plant, the team will issue a final report listing the cause as indeterminate. In these cases, assignment of corrective actions to preclude repetition is not required."

Supporting Information:

1) The St Lucie Unit 1 Main Generator is a Siemens/Westinghouse hydrogen intercooled unit rated 1200MVA. [D22]

2) A complete rewind and rotor replacement was completed for the St Lucie Unit 1 Generator for Extended Power Uprate (EPU) during the SL1-24 refueling outage [D19]. The uprated generator was required to meet a new output of 1200 MVA, 22 kV, 1800 rpm at 75 psig hydrogen pressures [D21,D22]

3) The St Lucie Unit 1 Generator Ratings are as follows [D22]:

Generator Rating	
Apparent Power (MVA)	1200
Power Output (MW)	1080
Power Factor (lagging)	0.9
Speed (RPM)	1800
Frequency (Hz)	60
Terminal Voltage (kV)	22
Stator Current @ 22 kV (A)	31492
Field Current (A)	7924
Field Voltage (V)	616
Number of Poles	4
Insulation Class	F
H2 Pressure (psig)	75

4) The EPU generator upgrade specification [D21] addressed an expected 40 year service life:

The uprated main generator, refurbished/rewound exciter rotor as well as the hydrogen coolers, exciter coolers, main leads, bushings and current transformers shall be designed for suitable operation for a minimum service life of 40 years under power uprate conditions.

5) The EPU generator upgrade specification [D21] describes technical requirements for the stator windings and insulation:

The stator coils shall be gas inner-cooled, single turn, half coils wound in open slots and secured in place by Kevlar coated molded glass-epoxy wedges. Each stator coil shall be made up of two half coils shaped on a former and joined together after assembly in the slots.

The stator coils shall be composed of solid copper strands in insulated ventilation tubes. Each stator coil strand shall be made of annealed tough pitch copper wire. All individual strands shall be insulated with a double thickness of continuous filament Dacron-Glass fibers having suitable thermal properties, high thermal stability and high abrasion resistance.

The coils shall utilize the latest stator coil construction materials, which include internal and external voltage grading material to improve the dielectric performance.

A glass backed mica paper tape and epoxy resin, rated for Class F insulation (155°C hot spot temperature limit) and working to Class B (130°C hot spot temperature limit) shall be used to provide the ground wall insulation of the stator coils superior dielectric and mechanical properties. The vacuum-pressure-impregnation (VPI) process shall be utilized.

The glass-backed mica paper tape shall be machine-applied over the entire length of the coil, straight part and end arms.

Prior to vacuum pressure impregnation, each coil shall be subject to a pre-heat cycle that removes residual moisture.

The coils shall be placed into an impregnation pan that shall be inserted into a tank, where a vacuum shall be drawn prior to introduction of the epoxy impregnation resin. Following impregnation, the coils shall be wrapped with a release film barrier and then placed into presses for curing in an oven.

6) The Siemens generator documentation [D22] includes a topical description of the Armature Coils:

[redacted]

7) Division of responsibility for EPU generator modification activities was specified within EC 246457 [D19]. The OEM was selected to perform various activities including the generator rewind and testing:

The work performed by the OEM is as follows:

1. *Replacement of the Main Generator Rotor and all associated removal including:*
   a. *Removing existing rotor from the 62 foot elevation to a transporter located at the 19.5 foot elevation by use of the turbine gantry crane.*
   b. *Lifting the replacement rotor from the 19.5 foot elevation to the 62 foot elevation by use of turbine gantry crane.*
2. *Rewinding of the Main Generator Stator and associated tests.*
3. *Replacement of the Exciter rotor and modification of Exciter and Generator coupling*
4. *Design and installation of new terminal board, TB-57*
5. *Removal of existing RTDs and installation of replacement RTDs.*
6. *Wiring of RTDs to the terminal strip in RTD Terminal Board TB-57 for customer interface.*
7. *Removal of existing FOVM vibration sensors and installation of replacement FOVM vibration sensors.*
8. *Removal of existing FOVM conduit boxes and installation of replacement FOVM conduit boxes internal to the Main Generator skirt.*
9. *Removal of existing stator slot couplers and installation of replacement stator slot couplers and associated wiring for IRIS partial discharge system.*
10. *Removal of existing termination box and installation of the external termination box for IRIS on the Main Generator housing.*
11. *Removal of the existing flux probe and associated wiring and installation of one replacement flux probe and one new flux probe and associated wiring.*
12. *Installation of the casing glands and the BNC connectors for the flux probes.*

8) The EPU modification activities to upgrade the St Lucie Unit 1 Generator were performed onsite between November 2011 and April 2012. [D10,D13,D23] Siemens performed the rewind and core replacement modification activities. Siemens work processes and procedures were used. As described in the customer report [D23] activities were grouped into "modules":

[redacted]

9) The 2012 customer report [D23] summarizes the process for inspecting, installing, and testing the bottom coils into the stator during Module 06 of the rewind. Two bottom coils (#35 and #42) were noted with minor damage during this process and were repaired. High potential test at 84kVdc was performed on the bottom coils after installation (before top coil install) with satisfactory results:

[redacted]

10)Minor damage to the insulation of two stator bars was noted after installation of bottom coils for the EPU modification [D23]. The coils with damage were located in slot #35 and slot #42 and repaired in place [D41]. No mention of any damage to bottom coil 17 was found.

11)IEEE standard 95 [D43] describes the recommended practice for testing the insulation of AC machines using high direct voltage (hipot), including acceptance proof testing for new equipment and maintenance proof testing equipment that has been in service:

[redacted]

12)ANSI C50.10 [D44] specifies the standard test voltages for acceptance testing:

[redacted]

13) The 2012 customer report [D23] summarizes the final testing performed on the stator during Module 13 after the rewind, which included dc high potential testing. The test was performed consistent with IEEE 95 using a test voltage of 76.5kVdc:

[redacted]

14) The testing performed on the Unit 1 generator windings during the 2012 rewind process subjected the insulation of stator bar B17 to an initial installation high potential test of 84 kVdc with satisfactory results, and a final high potential test of 76.5kVdc with satisfactory results. The final test satisfies IEEE 95 using a test voltage of 76.5kVdc based on (2E+1)*1.7 as described in ANSI C50.10 for dc test voltage, where E=22kV (rated line-to-line voltage of the generator). Therefore, the Unit 1 acceptance proof testing met the applicable industry standards for acceptance testing new equipment.

15) Warranty replacement of RTDs was performed during the Fall 2013 refueling outage. This scope included a maintenance high potential test in addition to routine Generator Crawl-Through Inspection.

[redacted]

16) Routine Generator Crawl-Through Inspection was performed by Siemens during refueling outages in Spring 2015, Fall 2016, and Spring 2018. These each included inspection of the turbine end winding.

Spring 2015 Inspection [D33]:

[redacted]

Fall 2016 Inspection [D34]:

[redacted]

Spring 2018 Inspection [D35]:

[redacted]

17)The Unit 1 generator ground fault lockout occurred on 04/25/2019 during the performance of a reactive capability test of the generator. The testing was being performed in accordance with procedure 0-OSP-53.01. The unit was operating at 100% reactor power. The generator was producing 1055MWe (gross) with 255MVAR (lagging) when the lockout occurred. During the test, Unit 2 was operating at -100MVAR (leading) to compensate for the excess reactive output from Unit 1. Generator terminal voltage was 22.7kV. [D1,D4, D6]

18)Insulation resistance testing of the generator was performed by site maintenance electricians during the post event investigations to verify the ground condition. The generator failed the initial 500Vdc test attempt after achieving only 9Vdc test voltage, demonstrating a ground internal to the generator. The ground resistance was measured as 1.88kOhm using a Digital Multimeter. Separation of the generator neutral connections was then performed and the testing repeated on each phase. This testing confirmed C Phase of the generator was grounded. [D13,D14]

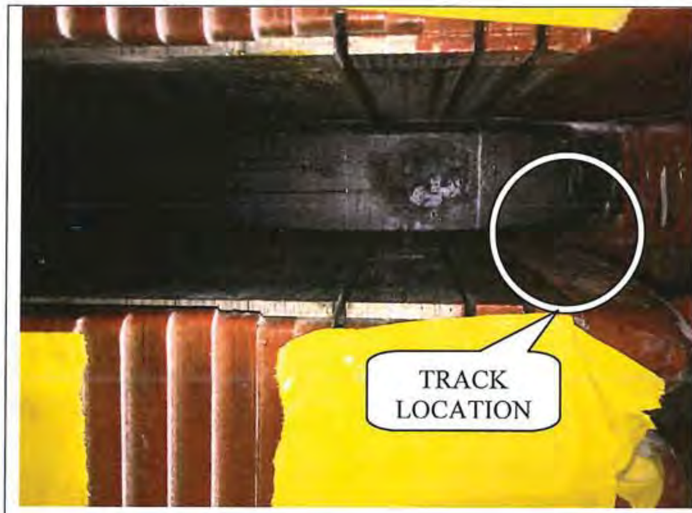
19)Internal inspection of the generator Lead Box was performed with no findings. Siemens staff performed internal disassembly to isolate the C Phase generator leads from the respective line and neutral bushings for additional Insulation Resistance tests. This testing demonstrated that the ground was located in the generator stator. Insulation Resistance Tests performed on the bushings were satisfactory. [O1,D14,D15].

20)Generator crawl through inspection was performed with no findings. Siemens staff performed a voltage drop test from each end of the C Phase Stator winding to ground. The purpose of the test was to determine the relative location of the ground fault from interpretation of the voltage drops as a function of the circuit length through the stator. This test indicated the fault was likely in a particular coil close to the turbine end of the stator. After breaking connections between individual Stator Bars it was determined the Bottom Bar in Slot 17 of the stator was grounded. [O3]

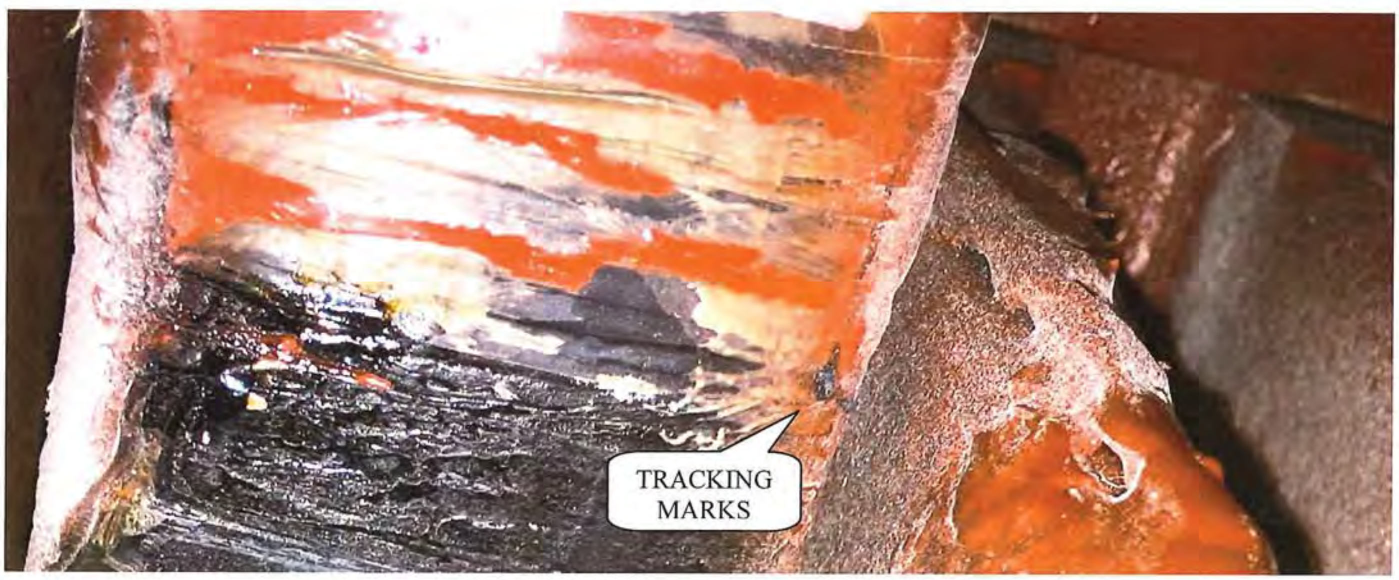
21)Additional testing of Stator Bar B17 insulation layers was performed to characterize the ground condition. The ICP layer in the stator bar contains a drain conductor that is connected to a strand at one end of the stator bar such that the individual strand insulation is bypassed. The drain conductor was disconnected and low voltage insulation resistance testing was performed. An insulation resistance test between the OCP and ICP layers confirmed a low resistance through the ground wall insulation. An insulation resistance test between the ICP and copper conductor strands confirmed that the strand insulation was intact. [O3]

22) Stator Bar T17 was removed allowing in-situ inspection of bar B17 in the slot. At the time of inspection there was on obvious indication of the fault. [O2]

Several pictures taken during the inspection show an area subsequently confirmed to be the location of the fault current track to ground just outside of the slot in the stator core laminations. Subtle tracking marks are evident from close review as shown below, though they are somewhat obscured by the armor layer taping and paint applied at the end winding area.



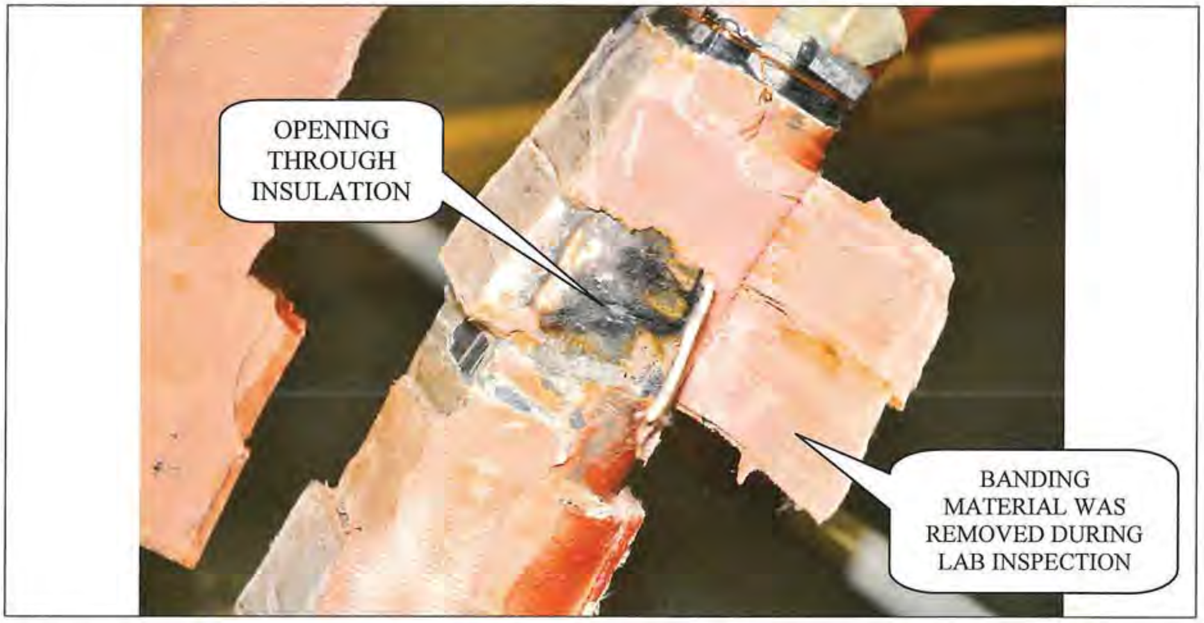
Close-up View:



23) After stator bar B17 was carefully removed from the generator the area of the fault current track to ground was apparent from visual inspection [O3]

24) Various materials removed from the stator were retained and transferred to Siemens for further testing and analysis in accordance with a testing plan [D31]. These materials included stator bar B17 and four additional stator bars that were removed whole to serve as test specimens.

After examination of B17 it was observed [D38, O5] that the fault current track to ground followed a path along the OCP layer originating at a small opening through the insulation that was located under spacer banding material:



The bar was cut approximately 9" on either side of the fault area and a CT scan was performed on the specimen. The CT imaging shows that the opening to a narrowing hole straight through the insulation to the ICP layer with no obvious involvement of the underlying copper strands.

[redacted]

25)A review of the ground fault [D42] was provided by FPL Power Generation Division staff supporting the St Lucie Unit 1 generator rewind and investigation activities. The PGD staff concluded that a "magnetic termite" was the most likely cause for the fault, but this conclusion was not definitive.

> *Based on the extent of core work performed during the 2012 rewind, the most likely root cause is an introduction of ferrous foreign material*
>
> ...
>
> *No definitive root cause was identified due to the damage at the failure location*

The opinion was based on visual characteristics of the fault in comparison with similar events after consultation with peers, but could not be claimed as definitive. This evidence supporting the presence of a magnetic terminate is circumstantial. No remains of any metallic or ferrous object (foreign or native) were found at the puncture site. Additionally, the location of the puncture under banding material applied using an epoxy provides conflicting evidence against the presence of a magnetic termite. The damaging activity of a ferromagnetic particle is generally prevented when the particle is captured / restrained by epoxy.

26)A Siemens internal analysis of the St Lucie stator ground fault is in progress. Siemens has shared a root cause statement [D45] based on this analysis work to date.

[redacted]

5. Evaluation Attributes

A. Previous Occurrences

The generator ground fault is not similar to past issues and is has not been determined to be either a repeat event or repeat occurrence in accordance with PI-AA-104-1000.

B. Extent of Condition

Identified Problem: The Extent of Condition (EOC) reviews for generator ground failures.

Object: St Lucie Unit 1 Main Generator

Defect: Grounded stator winding

Consequence: protective relay actuation and generator lockout

Same / Similar Analysis

<table>
<tr><td rowspan="2">Same Object:
Unit Main Generator</td><td>Same Defect:
Grounded stator winding</td><td>Same / Same:
St Lucie Unit 2 Main Generator</td></tr>
<tr><td rowspan="2">Similar Defect:
Stator Winding insulation failures:
Phase to Ground
Phase to Phase</td><td>Same / Similar:
Other types of fault paths through insulation failures to the stator are considered</td></tr>
<tr><td>Similar Object:
Generators and Motors with similar stator configurations</td><td>Similar / Similar:
Emergency Diesel Generators and other large motors used on site are subject to insulation failures.</td></tr>
</table>

The extent of condition reviews the St Lucie Unit 2 Main Generator for present insulation condition to ensure there is no current vulnerability for a fault. The Unit 1 and 2 Generators are provided with ground protective relays that will lockout the unit in the event of a ground fault. The units are also provided with differential protective relays that will lockout the unit in the event of a phase to phase type fault.

Although the electrical insulation system of any motor or generator could have a failure resulting in a fault, the extent of condition for this event will be limited to the Unit 2 Main Generator. Due to size and scale the Unit Main Generator stator designs and protection system arrangements are unique. These generators have stators constructed using half coil bars and complex arrangements for cooling. The Emergency Diesel Generators and all Medium Voltage motors used on site are relatively simple air cooled machines using form wound coils for stator windings. None of these machines have a stator construction similar to the Unit generators. In addition, the electrical systems (6.9 and 4.16kV) these machines are connected to have high impedance grounding with alarm, but no automatic tripping in the event of a ground fault.

Extent of Condition Review

EOC Action: review most recent insulation condition tests for the Unit 2 generator to determine if adequate confidence is provided for the current condition of the stator winding insulation. If necessary, ensure insulation condition tests are scheduled for next opportunity.

An inspection of the St Lucie Unit 2 generator was performed during the most recent SL2-24 refueling outage in 2018. This work included a generator crawl-through inspection, tuning weight inspection, exciter rotor swap out and electrical inspection, and rotor radial lead hardware upgrade. The generator was partially disassembled for this inspection and the rotor was removed [D18]. Electrical tests were performed including, insulation resistance test, polarization index test, and high potential test to 48,000Vdc. To the extent that the Unit 2 generator passed these tests and insulation successfully withstood the high potential test voltage it can be concluded there that a similar ground fault was not present and is not likely in the near term.

C. Extent of Cause

No causes within the scope of the station have been identified. Extent of cause is not applicable.

D. Safety Culture Evaluation

No causes within the scope of the station have been identified.

E. Risk/Consequence

The main generator and its protection systems are not safety related. However, a generator lockout initiates a turbine trip. Upon a turbine trip an automatic reactor trip is initiated by Loss of Load actuation in the Reactor Protection System (RPS) when reactor power >15%.

The operational crew entered 1-EOP-01, Standard Post Trip Actions, and then transitioned to 1-EOP-02, Post Trip Recovery. All CEAs fully inserted into the core and the trip was uncomplicated with all safety functions satisfied. The plant established in Mode 3 Hot Standby. Nuclear Regulatory Commission (NRC) was notified of the event per 10CFR 50.72(b)(2) due to RPS Actuation.

The ground fault was located in an inaccessible location of the generator stator and the affected stator bar assessed as unrepairable in place. An emergent Generator rewind was undertaken. This evolution has resulted in over 30 days of unplanned energy loss (UEL) beginning 4/25/19.

The event did not impact the environment and there were no radiological or security related implications

6. Operating Experience

An INPO OE search was completed for generator ground faults.

INPO TR4-38 July 2004	Topical Report - Review of Main Generator Failures
OE #102142 November 1990	South Texas Unit 1 Reactor Trip Due to a Generator Ground Fault Relay Actuation Caused by a Stator Coil End Turn Failure
OE #103441 December 1990	Braidwood Unit 1 REACTOR TRIP CAUSED BY MAIN GENERATOR PHASE C GROUND FAULT
[redacted]	
OE #287412 November 1988	Sequoyah Unit 1 TURBINE TRIP (POWER> 50%) A MAIN GENERATOR GROUND FAULT CAUSED A TURBINE TRIP WHICH CAUSED A REACTOR TRIP BECAUSE REACTOR POWER WAS ABOVE 50%. THE GROUND FAULT WAS CAUSED BY INSULATION BREAKDOWN ON THE "C" PHASE STATOR BAR T-17
OE #312004 (WANO) February 2014	Novovoronezh 5 Protection Actuation on a Ground Fault in Turbine Generator Stator Winding Caused a Main Generator Trip and Subsequent Unit Load Reduction
[redacted]	

Additional External OE was identified by PGD staff. Two presentations regarding generator failures having some similarity to the St Lucie Unit 1 ground fault were reviewed.

Detroit Edison (DTE) "Inleakage of H2 into Stator Water Cooling" [D36] September 2009	Fermi 2 generator shutdown due to H2 leakage into water cooled stator. Caused by magnetic termite wormhole discovered in stator produced by small steel particle.
Electrabel Belgium "EPRI Generation Workshop Rome, April 2013"	500MW Jeumont generator (Westinghouse design) trip via earth fault relay after failure of stator winding bottom bar. Although no physical evidence presence of domestic or foreign object cannot be eliminated.

Brief review of certain OE is provided below. Based on the information reviewed to date there is no OE directly relevant to the event.

[redacted]

INPO IER L2-11-2 Scram Analysis:

The Main Generator is an SPV component, therefore Recommendation 2 of IER L2-11-2 pertaining to SPV elimination and mitigation strategies is directly applicable. The Main Generator has been classified as an SPV/FID1. The St. Lucie scram analysis response has credited SPV mitigating strategies including preventive maintenance, replacement, and design modification.

SPV elimination is not credible for the generator, however the uprate completed in 2012 addressed both replacement and modernization improvements. Various preventive maintenance activities address the generator. By its nature the activities for the stator are limited to monitoring (inspect and test) activities, however these are consistent with industry practice. No gaps in this area are apparent.

7. Lessons Learned - An important opportunity of the root cause evaluation process is the identification of lessons learned for organizational learning. These lessons learned can be shared with the organization through formal communications, department briefings or training.

The St Lucie Unit 1 Generator ground fault occurred in 2019, but it was initiated in 2012 during an onsite generator upgrade. It is to be recognized that there exists some unavoidable assumed risks when undertaking the manufacture and onsite assembly of a generator stator.

- The conditions under which activities are performed onsite cannot be optimized to the level of a manufacturing facility. Unless and until a change in the state of the art is developed, such that a 1200MVA size stator could be fully manufactured and assembled offsite under controlled conditions and then installed at the station, then complex onsite assembly activities are necessary.
- Accepted methods of testing will not reliably detect certain minor but significant deficiencies during the manufacture and assembly of a stator. Minor damage to insulation, introduction of a contaminant, or very small particle internal to a generator, can remain undetected. The minor deficiency can result in significant damage to stator insulation overtime and ultimately may take years to materialize as a fault.

Organizations performing significant generator maintenance should review this evaluation for the Unit 1 generator ground fault as a case study. This review should be used as a tool to challenge processes and work plans for enhancement opportunities beyond current industry standards.

8. Corrective Actions

Area	Corrective Action/Assignment	Responsible	Assignment Type	Due Date
Direct Cause - A small puncture developed through the ground wall insulation of stator bar B17 in the phase C Stator Winding resulting in a fault current path to ground.	Complete rewind of the Unit 1 generator to restore stator winding to serviceable condition.	Maintenance Programs	CA	COMPLETE
Interim – Forensics Testing	Track completion of forensics testing as prescribed in Attachment E	RCE Sponsor Mark Jones	MA	COMPLETE
	Re-establish Root Cause Team to complete final Evaluation based on findings of forensics testing. Revise RCE Charter with updated team scope and schedule	RCE Sponsor Mark Jones	MA	COMPLETE
Extent of Condition- Unit 2 Generator	Review maintenance history for Unit 2 Generator to determine near term risk for stator insulation resistance	Root Cause Team	CA	COMPLETE
Enhancement – Lessons Learned	Complete a Self-Assessment of Siemens implementation plans (material handling, FME plans, cleanliness and housekeeping requirements) against the lessons learned from the Unit 1 Generator Ground Fault for enhancement opportunities beyond current industry standards.	Maintenance Programs	MA	10/11/19
External Root Cause – Siemens	Document Completion of Siemens internal Root Cause Analysis.	RCE Sponsor Mark Jones	MA	10/11/19

9. Deferral Justification

There are no CAPR and CA actions deferred.

10. Effectiveness Review Plan

No causes within the scope of the station have been identified. As such there is no specific CAPR to be addressed in an EFR plan.

11. Sources Cited

Documents:

#	**Document Title**
D1.	AR 02312208 UNIT 1 AUTOMATIC REACTOR TRIP
D2.	AR 02312219 NRC Notification
D3.	AR 02312560 LER
D4.	0-OSP-53.01 "Reactive Power Lagging Capability Test" performed 4/25/19
D5.	Turbine Generator Vibration Summary for Lagging Test 4/25/19
D6.	U1 Ops Narrative Logs April 25, 2019
D7.	Enterprise Wide Information System (EWIS) St Lucie Data / PI Process Book
D8.	8770-B-327 sh890
D9.	8770-B-327 sh1250
D10.	WO 40066477 SL1-248 Generator Rewind (EPU)
D11.	WO 40168563 SL1-25 Rotor Inspection
D12.	WO 40272487 SL1-25 Generator High Pot
D13.	WO 40661261-10 U1 GEN MAIN ACCESS LEAD BOX FOR MEGGER - FAR 10
D14.	Summary of Failure Investigation Process Field Actions and Results
D15.	WO 40661017-18 U01 GENERATOR MEGGER TEST FIP - FAR 3
D16.	EPRI EL-5036 "Power Plant Electrical Reference Series, Volume 1 Electric Generators"
D17.	EPRI EL-5036 "Power Plant Electrical Reference Series, Volume 16 Handbook to Assess Insulation"
D18.	Siemens Customer Report for St Lucie Unit 2 Generator September 2018
D19.	EC 246457 "UNIT 1 GENERATOR ROTOR REPLACEMENT AND STATOR REWIND"
D20.	IEEE Press "Electrical Insulation for Rotating Machines" by Stone, Boulter, Culbert, Dhirani
D21.	Specification SPEC-E-037 Rev. 3 "Main Generator and Exciter Upgrade"
D22.	Manual 8770-4139 Rev. 17 "Siemens Hydrogen Inter-cooled Turbine Generator"
D23.	Siemens Customer Report for St Lucie Unit 1 Generator Rewind and Core Replacement completed February 2012
D24.	WO 40011327 SL1-24 Generator Rewind
D25.	Siemens Customer Report for St Lucie Unit 1 Generator October 2013
D26.	PSDS Field Data

#	Document Title
D27.	WO 40503468-01 SL1-28 Generator Grounding and Testing
D28.	WO 40391932-01 SL1-27 Generator Grounding and Testing
D29.	AR 02167611-01 CE SUPPLEMENT TO AR 2167433 LOW GEN MEGGER
D30.	Understanding Generator Ground Faults
D31.	Siemens Testing Summary and Acceptance Criteria [proprietary data]
D32.	WO 40168563-01 SL1-25 Rotor Insp.
D33.	Siemens Customer Report for St Lucie Unit 1 Generator 2015
D34.	Siemens Customer Report for St Lucie Unit 1 Generator 2016
D35.	Siemens Customer Report for St Lucie Unit 1 Generator 2018
D36.	"Inleakage of H2 into Stator Water Cooling" DTE presentation on Fermi 2 experience, 2000 International Joint Power Generation Conference & Exposition
D37.	Electrobel/GDF Suez presentation on fault attributed to magnetic termite, EPRI Generation Workshop Rome 2013
D38.	Siemens Document ID: DPTRP-0005707601 "TGME Materials Laboratory Testing as Part of St. Lucie Ground Fault RCA Investigation" dated 18-July-2019 Siemens Confidential and Siemens proprietary information
D39.	Unit 1 Fiber Optic Vibration Monitor Routine Data through March 2014
D40.	FME Plan for Siemens Turbine Generator Work Scope at St. Lucie Dated 26 August 2013 (Following EPU)
D41.	St Lucie RCA Follow Up - Email Correspondence regarding Siemens PCM responses to noted minor damage to bottom coils during installation.
D42.	AR 2151217
D43.	IEEE 95 "IEEE Recommended Practice for Insulation Testing of AC Electric Machinery (2300 V and Above) With High Direct Voltage"
D44.	ANSI C50.10-1990 "Rotating Electrical Machinery – Synchronous Machines"
D45.	St Lucie U1 Stator Ground Fault Root Cause Statement Siemens Letter dated June 24, 2019

Observations:

#	Observation
O1.	Generator Crawl through field notes/pictures
O2.	Top Coil Removal and slot inspection field notes/pictures
O3.	Slot 17 Bottom Coil Removal and field notes/pictures
O4.	Photo documentation of EPU Generator Rewind, Nov.-Jan. 2012, St Lucie Unit 1
O5.	Photo documentation of Laboratory Testing June-July 2019, Siemens Energy Charlotte, NC

Interviews:

#	Interview
I1.	Former FPL FME Coordinator

12. Attachments

A. Root Cause Charter

B. Fault Tree Analysis

C. Support Refute Matrix

D. Event and Causal Factors Chart

ROOT CAUSE CHARTER

Facility: St. Lucie Nuclear
Condition Report: 2312208
Manager Sponsor: Mark Jones (Engineering)

Event Description
At approximately 0918 on 4/25/2019, Unit 1 reactor and turbine automatically tripped due to a Main Generator ground.

Preliminary Problem Statement
Object: U1 Main Generator
Defect: experienced a phase to ground electrical fault
Consequence: resulting in an automatic reactor and turbine trip.

Preliminary Extent of Condition
Extent of condition preliminarily defined as U2 Main Generator.
Extent of cause preliminarily defined as U1/U2 Main Turbine and U1/U2 Main Generator

Investigation Scope and Methodology
At a minimum, the RCE shall address the following:

- Root and Contributing Causes
- Extent of Condition and Extent of Cause
- Corrective Actions and Effectiveness Measures

The following investigation methodologies shall be considered for use by the RCE team:

- Hazard/Barrier/Target Analysis
- Event and Causal Factor Charting
- Organizational and Programmatic Failure Analysis

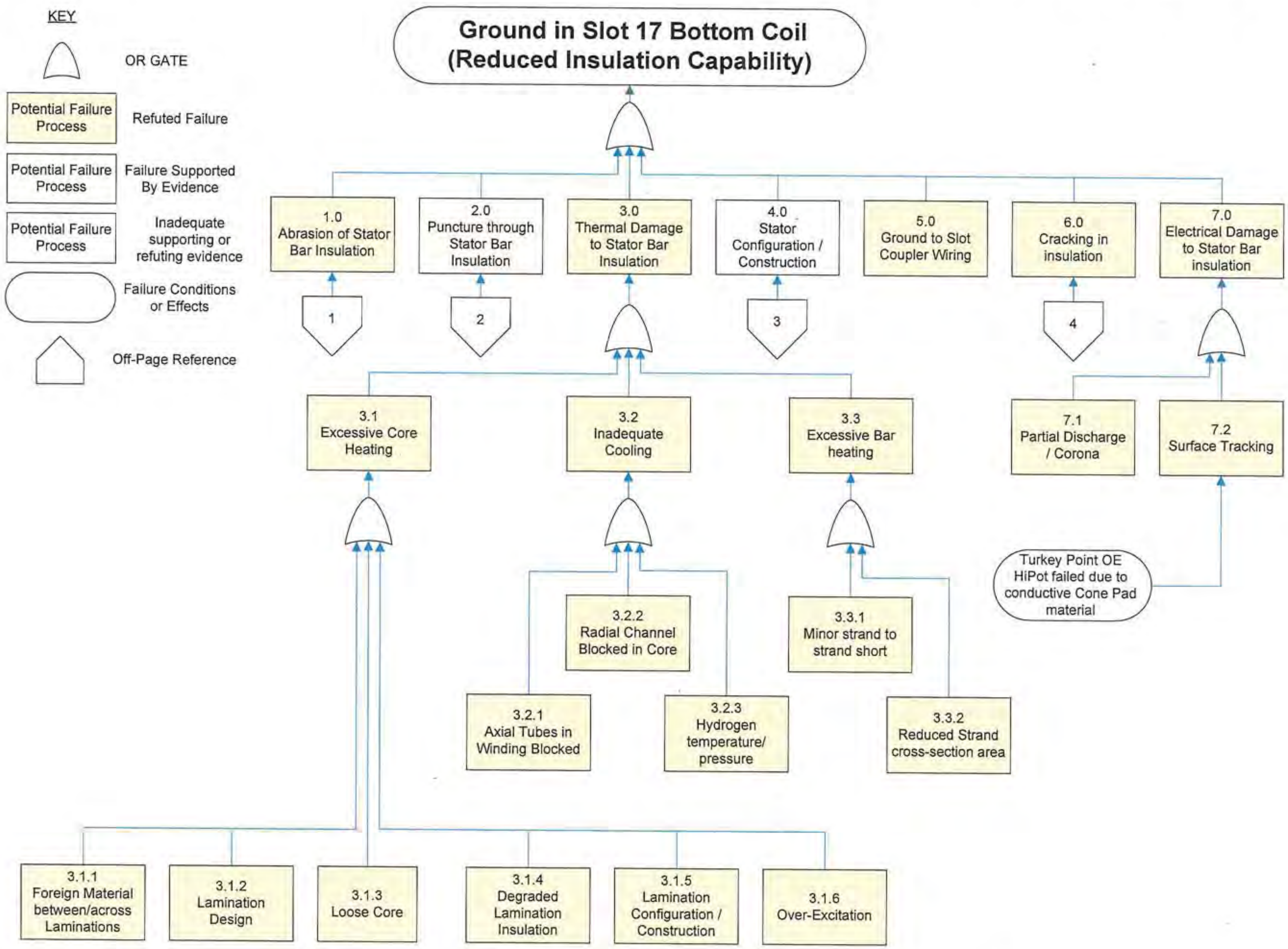
Team Members
Team Leader: A. Bouchfaa (Engineering)
Team Root Cause Evaluator: Gary Arntson (Engineering)
Team Member: Andy Terezakis (Operations)
Team Member: Don Zoll (Electrical Maintenance)

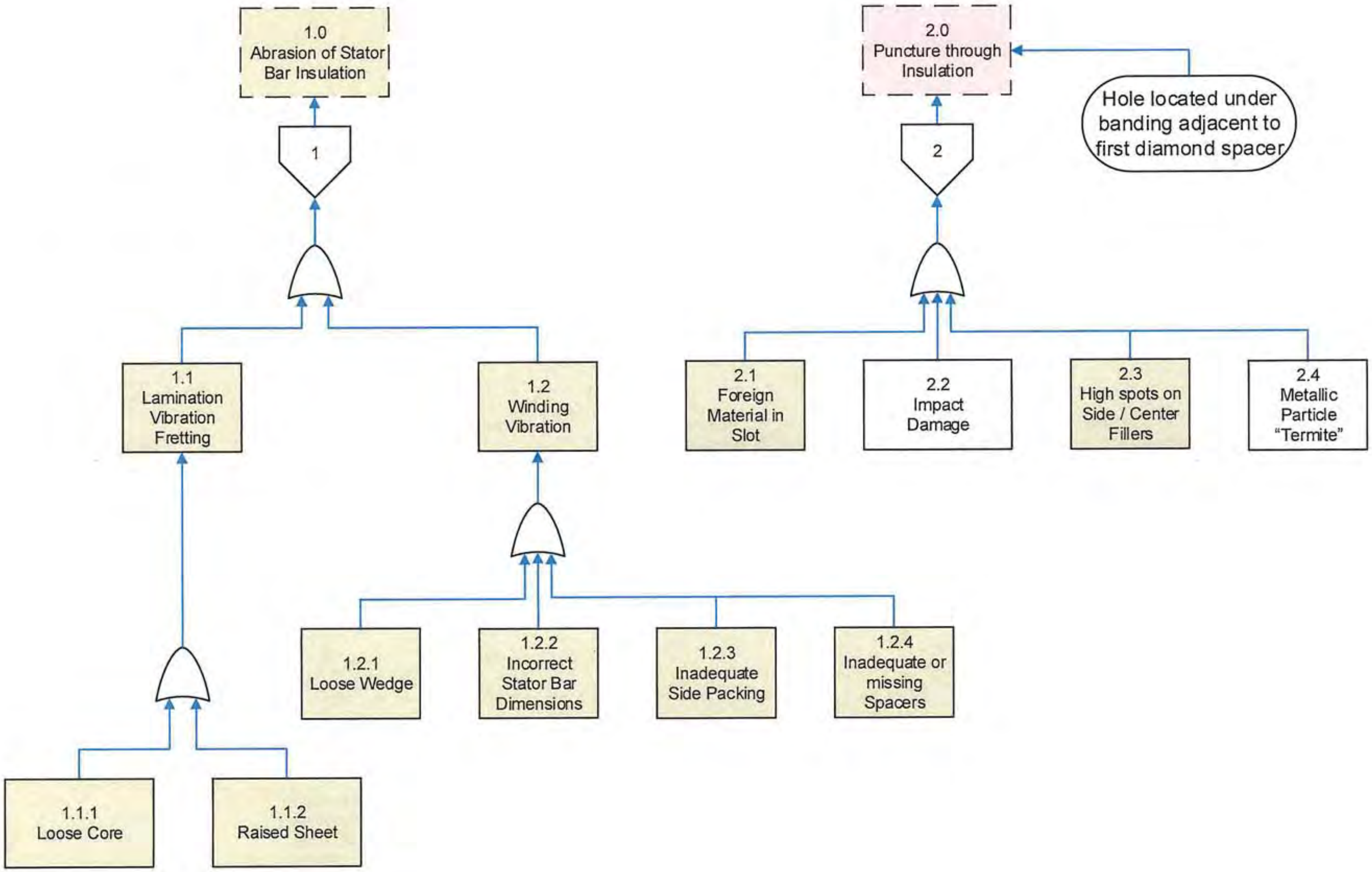
Milestones
Date Assigned: 05/06/2019
Status Update: 05/20/2019
Draft Report Date: 05/31/2019
Final Report Date: 06/05/2019

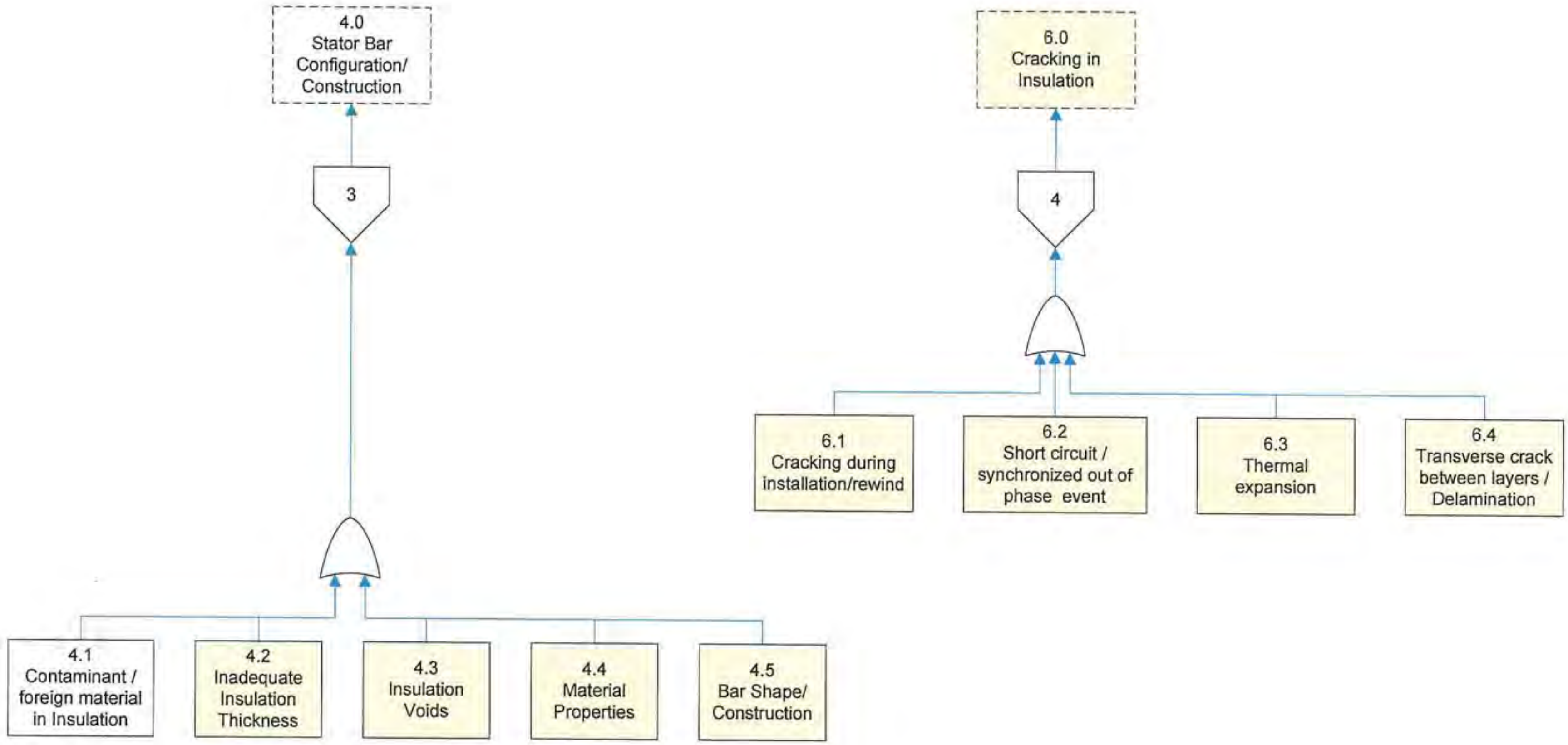
Communications Plan: Weekly updates to MRC. Daily updates will be provided during the early, critical discovery phase of deconstruction and repairs.

Sponsor Approval: Mark Jones Date: 5/30/2019

MRC Approval: Dan DeBoer Date: 5/~~31~~ 30/19


KEY
OR GATE
Potential Failure Process
Refuted Failure
Potential Failure Process
Failure Supported By Evidence
Potential Failure Process
Inadequate supporting or refuting evidence
Failure Conditions or Effects
Off-Page Reference
Ground in Slot 17 Bottom Coil (Reduced Insulation Capability)
1.0 Abrasion of Stator Bar Insulation
2.0 Puncture through Stator Bar Insulation
3.0 Thermal Damage to Stator Bar Insulation
4.0 Stator Configuration / Construction
5.0 Ground to Slot Coupler Wiring
6.0 Cracking in insulation
7.0 Electrical Damage to Stator Bar insulation
1
2
3
4
3.1 Excessive Core Heating
3.2 Inadequate Cooling
3.3 Excessive Bar heating
7.1 Partial Discharge / Corona
7.2 Surface Tracking
Turkey Point OE HiPot failed due to conductive Cone Pad material
3.2.2 Radial Channel Blocked in Core
3.3.1 Minor strand to strand short
3.2.1 Axial Tubes in Winding Blocked
3.2.3 Hydrogen temperature/ pressure
3.3.2 Reduced Strand cross-section area
3.1.1 Foreign Material between/across Laminations
3.1.2 Lamination Design
3.1.3 Loose Core
3.1.4 Degraded Lamination Insulation
3.1.5 Lamination Configuration / Construction
3.1.6 Over-Excitation


1.0
Abrasion of Stator Bar Insulation
1
1.1
Lamination Vibration Fretting
1.2
Winding Vibration
1.1.1
Loose Core
1.1.2
Raised Sheet
1.2.1
Loose Wedge
1.2.2
Incorrect Stator Bar Dimensions
1.2.3
Inadequate Side Packing
1.2.4
Inadequate or missing Spacers
2.0
Puncture through Insulation
Hole located under banding adjacent to first diamond spacer
2
2.1
Foreign Material in Slot
2.2
Impact Damage
2.3
High spots on Side / Center Fillers
2.4
Metallic Particle "Termite"


4.0
Stator Bar
Configuration/
Construction
3
4.1
Contaminant /
foreign material
in Insulation
4.2
Inadequate
Insulation
Thickness
4.3
Insulation
Voids
4.4
Material
Properties
4.5
Bar Shape/
Construction
6.0
Cracking in
Insulation
4
6.1
Cracking during
installation/rewind
6.2
Short circuit /
synchronized out of
phase event
6.3
Thermal
expansion
6.4
Transverse crack
between layers /
Delamination

1.0	Failure Process # 1 – Abrasion of Stator Bar insulation Description: Abrasive wear through the surface of the ground wall insulation					
	CAUSE	VERIFICATION	EXPECTED / NORMAL	ACTUAL	CONCLUSION	NOTES
1.1	Lamination Vibration Fretting	Determine if fretting of insulation is present on stator bar insulation: 1. Field visual inspection of slot 17 stator bars before and after removal 2. Field visual inspection of slot 17 after stator bars and fillers are removed	No significant evidence of insulation damage due to fretting as indicted by greasing or dusting indications on bars or in slot	External inspection of the top and bottom bars from slot 17 was completed. Inspection of stator slot 17 was completed after bar removal. No evidence of fretting was identified and no indications were found for a raised lamination [O2,O3]	This failure mode can be refuted. No evidence supporting lamination vibration has been noted.	Initial Visual observation of bottom 17 bar shows indication of ground fault outside of the slot area on turbine end. Confirmed during Siemens Lab Testing [D38]
1.1.1	Loose Core	See 3.1.3				
1.1.2	Raised Sheet (lamination)	Perform visual inspection with check by feel for raised lamination in slot 17	Sheets properly aligned in core stack			
1.2	Stator Bar Vibration	Determine if indications of insulation abrasion due to vibration are present: 1. Field visual inspection of slot 17 stator bars before and after removal	No significant evidence of rubbing or wear through insulation damage due to vibration of the bar within the slot or out of slot at the end turns	Field inspection of the top and bottom bars from slot 17 was completed. There were no obvious indications of insulation abrasion.	This failure mode is refuted. There has been no abrasive damage identified and no supporting evidence was found for any of the various causes of vibration. Identification of the fault location under banding for the end arm [D38]	

1.0	**Failure Process # 1 – Abrasion of Stator Bar insulation** Description: Abrasive wear through the surface of the ground wall insulation					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
1.2.1	Loose Wedge	Perform PSDS (pre stress driving strip) Wedge Tightness	PSDS Wedge Tightness within specification	Review of as-found PSDS deflection data shows the slot 17 wedges were generally consistent for all the wedges and with those of the adjacent wedges [D26]. Inspection of slot 17 wedges, PSDS and filler materials did not show any abnormalities. Material testing of wedge and PSDS samples from slot 17 was normal and consistent with expectations for in service components.	No supporting evidence for loose wedging.	Outliers in PSDS deflection were identified. The outlier data points were consistent with bad micrometer readings (inadequate depth measurement rather than loose wedging) and have been discounted.
1.2.2	Incorrect Bar Dimensions	Validate bar dimensions after stator bar removal	Stator Bar dimensions within Siemens specifications	Dimensions in the cell region were consistent along the length of the bar and measured within expected tolerances.[D38]	No supporting evidence for irregular bar dimensions	
1.2.3	Inadequate Side Packing	Inspect prior to removal and check for bar loose fit in the slot during removal from stator	Assess fit during bar removal from Slot 17. Inspect removed bar and side packing materials for evidence of abrasion	Side packing appeared tight during bar removal.[O3] Inspection of slot 17 side filler materials did not show any abnormalities. Material testing of side filler material was normal.[D38]	No supporting evidence for inadequate side packing.	

1.0	**Failure Process # 1 – Abrasion of Stator Bar insulation** Description: Abrasive wear through the surface of the ground wall insulation					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
1.2.4	Inadequate or Missing Spacers	Validate all spacers in place during bar removal from slot	All spacer in place in accordance with Siemens specifications Inspect removed stator bar and spacer materials for evidence of abrasion	Inspection did not reveal any missing spacers. All center fillers were accounted for between top and bottom bars in slot 17.[O2,O3,D38] Review of original bump test data indicated no resonances. [D23] Initial readings by FOVM were low and further readings were suspended. [D39] Inspection of slot 17 center filler materials did not show any abnormalities.[D38]	No supporting evidence for inadequate or missing spacers.	

2.0	**Failure Process # 2 – Puncture through insulation** Description: A hole is punctured through the ground wall insulation resulting in fault					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
	Puncture [hole] through insulation	Identify location of fault and examine for any direct evidence that insulation was punctured. 1. Non Destructive CT exam of bar 2. Visual and Microscopic Exam of fault area surface	Insulation is free from indications of puncture damage	The ground wall insulation was breached through a small hole in the insulation apparent from visual inspection. The hole was located adjacent to the first set of diamond spacers on the end arm underneath a layer of banding material. The banding material covering the breach was not punctured. [D38]	It is concluded that the insulation breach occurred due to puncture through the ground wall insulation.	The hole has an opening at the OCP surface of approximately 15mm long x 2mm wide, with elongated conical shape through the insulation ending at a small point where the inner most insulation layers interface with the ICP layer.
2.1	Foreign Material in Slot	Inspect stator bar and slot after removal for evidence of Foreign Material Additional exam and testing as described in 4.1	No foreign materials found in slot during visual inspections	No visually identifiable foreign materials have been found after bar removal from Slot 17. Confirmed Fault location is not in the cell/slot area of the stator bar.	Damage to the insulation due to a foreign material in the stator slot is refuted	

2.0	**Failure Process # 2 – Puncture through insulation** Description: A hole is punctured through the ground wall insulation resulting in fault					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
2.2	Impact Damage [mechanical puncture, chip, or gouge in insulation that progresses through remainder of insulation over time]	Impact damage to insulation 1. Visual and Microscopic Exam of fault area surface for puncture with adjacent area cracking or crazing 2. Section Bar and perform visual and microscopic exam of insulation at fault for evidence of puncture with adjacent area cracking or crazing 3. Non Destructive CT exam of bar	No puncture of insulation with evidence of cracking or partial discharge damage in surrounding insulation.	Puncture through the ground wall insulation identified under banding material adjacent to diamond spacer. Puncture was through full depth of the ground wall insulation but did not penetrate the ICP [D38].	Location demonstrates that any impact damage could only have occurred before application of banding during rewind. Pre-existing impact damage at the time of installation cannot be refuted. However, there is no additional evidence for a propagating mechanism such as cracking.	The coils passed initial High Potential testing at 76500Vdc. Any significant pre-existing damage would have resulted in failed preoperational testing. This mechanism is only credible for a minor puncturing through a small % of the ground wall which then propagates over time by another mechanism.
2.3	High spot or anomaly on side fillers or center filler	Visual Exam of stator bar and middle and side fillers from slot 17	No evidence of localized insulation damage from nonconforming filler materials.	The fault location was identified after bar removal from Slot 17. Insulation damage was identified in a location outside of the slot [D38]	Puncture of the insulation by some anomaly of slot filler materials can be refuted due to the location of the insulation damage	

2.0	**Failure Process # 2 – Puncture through insulation** Description: A hole is punctured through the ground wall insulation resulting in fault					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
2.4	Metallic Particle / "Magnetic Termite" [small ferromagnetic object wears through insulation producing a hole due to combined effects of magnetic attraction and vibration due to eddy currents]	Fault occurs though hole straight through the insulation [sometimes referred to as a wormhole due to appearance], Presence of metallic or ferrous object in insulation 1. Visual and Microscopic Exam of fault area surface 2. Section Bar and perform visual and microscopic exam of insulation at fault 3. Non Destructive CT exam of bar 4. Electron Dispersion Spectroscopy (EDS) of fault area for metallic / ferrous contaminants	No evidence of puncture straight through the insulation No metallic or ferrous object or contaminants	Puncture through the ground wall insulation identified under banding material adjacent to diamond spacer. Fault was straight through the insulation.[D38] No remains of any macro metallic object were found in the hole. EDS identified Fe and Mn contaminants in materials adjacent to fault location indicating presence of carbon steel, origin of contaminants is unclear as cross contamination during sample preparation can't be ruled out.[D38]	The shape and direction of the hole are consistent with a magnetic termite. [D36,D37] Though no object was found in the hole to allow a definitive identification, it is feasible the object would vaporize or melt and be ejected during the fault. Evidence supporting the presence of a magnetic termite is circumstantial.	Based on the fault location under banding materials, any termite must have been introduced in the stator during the 2012 rewind. The presence of a termite would not result in failure of High Potential Testing performed on the new stator after rewind. Subsequent High Potential Testing may or may not fail depending on the progress of the terminate into the insulation If a ferromagnetic particle is captured within insulation material this may restrain the particle and prevent vibration leading to it termite effect. This is a potentially counter point for presence of a termite under the banding material. However, there was a large void in the binding epoxy over the fault area and it remains unproven whether epoxy binding resin could permanently restrain a termite.

3.0	**Failure Process # 3 – Thermal Damage to insulation** Description: Insulation is continuously operated above its design temperature. Significant accelerated aging leads to failure					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
	Thermal Damage to Insulation	Section Bar 17 at various locations and perform visual and microscopic exam of insulation for direct evidence of overheated / aged condition in fault location as compared to non-fault locations	Consistent satisfactory condition in all insulation sections, no signs of overheating / aging	Various sections of insulation on bar B10 (control sample) and B17 were inspected with no indications of overheating.	All failure processes for thermal damage are refuted. No other evidence supporting thermal damage has been noted. This failure mode is refuted.	
3.1	Excessive Core Heating					
3.1.1	Foreign Material between/ across Lamination [localized heating due to shorted laminations]	1. Perform field inspection of slot 17 laminations 2. Perform core imperfection test (EL-CID/SMCAS) 3. Remove and insect affected laminations (if warranted)	No heating or tracking indications on slot 17 laminations No significant indications in slot 17 laminations	No evidence of FME or in the core [O3] Initial SMCAS after fault does not show significant indications at slot 17 The core was found in generally serviceable condition after generator stripping. Disassembly for inspection and repair was not necessary.	Core faults due to FME in slot 17 can be refuted.	No faults found in these locations by SMCAS and Loop tests after 2011 rewind

3.0	**Failure Process # 3 – Thermal Damage to insulation** Description: Insulation is continuously operated above its design temperature. Significant accelerated aging leads to failure					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
3.1.2	Lamination Design	1. Perform field inspection of slot 17 laminations 2. Perform core Loop test at rated flux	Consistent satisfactory condition in all redial sections of laminations adjacent to 17, no systemic indications	The core was found in generally serviceable condition after generator stripping. No evidence of overheating [O3] Initial SMCAS after fault does not show any systemic indications. A Loop test has been also been performed finding a consistent thermal response to rated flux and no thermal anomalies present	Design of the laminations can be refuted as a cause.	Reactive Capability Testing was underway during the fault. The voltage was only raised by 2.3% and the reactive power was well within the capability curve
3.1.3	Loose Core	1. As-found SMCAS 2. Visual inspection after removal 3. Knife test 4. Post-Removal SMCAS (Core Loop Test if indicated) 5. Through bolt tightness checks, visual inspection of belleville washers	SMCAS/Knife test within Siemens specifications Visual inspection with no anomalies Bolts tightened to Siemens specification	Some end iron issues were noted that were clearly due to generator stripping activities. No loose core lamination issues for slot 17. [O3] Initial SMCAS after fault does not show any systemic indications. A Loop test has been also been performed and no thermal anomalies were present	Core looseness can be refuted as a cause.	

3.0	Failure Process # 3 – Thermal Damage to insulation Description: Insulation is continuously operated above its design temperature. Significant accelerated aging leads to failure					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
3.1.4	Degraded Lamination Insulation [localized heating due to shorted laminations]	See 3.1.1	No heating or tracking indications on slot 17 laminations No indications in stator core laminations Lamination insulation is intact with no signs of degraded condition or overheating	The core was found in generally serviceable condition after generator stripping. No evidence of overheating from surface inspection. [O3] Initial SMCAS after fault does not show any systemic indications. A Loop test has been also been performed finding a consistent thermal response to rated flux and no thermal anomalies present Disassembly for inspection and repair was not necessary.	Cause is refuted. Satisfactory inspections and testing demonstrates lamination insulation is not degraded	
3.1.5	Lamination Configuration / Construction	See 3.1.1	Lamination configuration, (shape, size, thickness etc.) is per specifications.	The core was found in generally serviceable condition after generator stripping. [O3] Initial SMCAS after fault does not show any systemic indications. A Loop test has been also been performed finding a consistent thermal response to rated flux and no thermal anomalies present Disassembly for inspection and repair was not necessary.	Satisfactory inspections and testing demonstrates core configuration problem is refuted.	

3.0	**Failure Process # 3 – Thermal Damage to insulation** Description: Insulation is continuously operated above its design temperature. Significant accelerated aging leads to failure					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
3.1.6	Over-excitation of generator	Review generator data recorded during reactive capability test	Generator Reactive Load (MVAR) and Exciter Amps within capability ratings	Generator was maintained at 255MVAR during the reactive load test.[D4]	Over-excitation is refuted. Generator was maintained within excitation limits	The generator capability limit for the test conditions was 510MVA
3.2	Inadequate Cooling					
3.2.1	Ventilation Tubes in Bar Blocked	1. Perform inspection of cooling tubes 2. Review hot gas temperature history data	cooling tubes are open and free of any debris no outlier in hot gas temperatures prior to fault event, consistent temperature response during reactive capability testing	Cooling tube inspection completed on various sections with no distortion or blocking observed [D38] Generator temperatures maintained well within specifications and generally consistent at all RTD locations leading up to generator lockout [D7]	Blocked cooling tube in stator bar B17 is refuted.	
3.2.2	Cooling Channel Blocked in Core (Axial Channels, plus additional radial channels in step iron)	Perform field inspection of cooling channels in slot 17 and adjacent slots for blockage	Stator cooling channels are open and free of any debris	No evidence of cooling tube blockage was observed. [O1,O2] The fault location was identified after bar removal from Slot 17. Insulation damage was identified in a location outside of the slot [D38]	Blockage of H2 cooling in core is refuted.	

3.0	**Failure Process # 3 – Thermal Damage to insulation** Description: Insulation is continuously operated above its design temperature. Significant accelerated aging leads to failure					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
3.2.3	Inadequate Hydrogen Temperature / Pressure	Review hot gas temperature history data.	H2 pressure and hot gas temperatures prior to fault event within specifications, consistent temperature response during reactive capability testing	Pressures and temperatures continuously monitored and checked within limits shifty. Pressures validated prior to testing, consistent temperature response at recorded RTD locations leading up to generator lockout [D4,D7]	Inadequate Hydrogen system performance is refuted.	
3.3	Excessive Bar Heating					
3.3.1	Strand to Strand Shorts	Section Bar and perform visual inspection of strand insulation for overheating / evidence of shorted strands	Consistent appearance of strand insulation, no signs of overheating or shorts between strands	Sections of Bar B17 adjacent to the fault area were polished and inspected. No evidence of shorting between strands was found.	Overheating due to strand to strand shorts is refuted	
3.3.2	Reduced strand cross-section area [localized ampacity issue]	Section Bar and perform visual inspection of strands	Consistent cross section shape and size of strands in cross section	Sections of Bar B17 adjacent to the fault area were polished and inspected. Strands were of consistent shape/size and no deformation noted, no indication of overheating in strand insulation or adjacent material was found.	Overheating due to inadequate conductor cross section is refuted.	

4.0	**Failure Process # 4 – Stator Bar Configuration** Description: The construction of the bar does not conform to design specifications. Loss of margin to a critical design characteristic resulted in premature failure.					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
4.1	Contaminants / Foreign Material in Insulation	1. Microscopic Exam of fault area surface 2. Section Bar and perform Microscopic Examination of insulation at fault 3. Spectroscopy if warranted by inspections	Insulation layer is free of any foreign material or contaminants	Various sections of bar B10 (control sample) and B17 were polished and inspected visually and microscopically, including section of bar on either side of the faulted area sample. No indications of foreign material within the ground wall insulation were noted. [D38] Spectroscopy performed on surface of (FTIR and EDS) fault location did not support the presence of a contaminant in the insulation; however EDS identified some copper and ferrous contaminants on the surface outside of the fault area. Origin of these contaminants is unclear as cross contamination during sample preparation can't be ruled out.[D38]	No gross contamination of the insulation was found. Though unlikely, the presence of a contaminant / object at the singular location of the fault can't be factually refuted. Due to loss of material from the fault location the existence of any contaminant in this material prior to the fault is indeterminate.	The coils passed multiple initial High Potential tests including final test at 76500Vdc. Significant pre-existing contamination would likely have resulted in failed preoperational testing. This mechanism is only credible for a small amount of material affecting a small % of the ground wall (possibly on between one half lapped layer) of which then propagates over time by another mechanism.

4.0	Failure Process # 4 – Stator Bar Configuration Description: The construction of the bar does not conform to design specifications. Loss of margin to a critical design characteristic resulted in premature failure.					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
4.2	Inadequate Insulation Thickness	1. Section Bar and perform visual and microscopic exam of insulation at fault 2. dimensional measurements of insulation thickness	Verify lapping configuration and insulation dimensions Configurations and copper and insulation sizes conform with drawings (Siemens)	Bar dimensions were measured and verified to specification. Various sections of bar B10 (control sample) and B17 were polished and inspected visually and microscopically, including section of bar on either side of the faulted area sample. Consistent and acceptable Insulation configuration and condition in all samples. High Voltage Breakdown test of B10 and B17 samples exceeded specifications. [D38]	Insulation Thickness is refuted	B17 sample withstood equivalent of 99kVac for 1 minute prior to flashover during High Voltage breakdown test.

4.0	**Failure Process # 4 – Stator Bar Configuration** Description: The construction of the bar does not conform to design specifications. Loss of margin to a critical design characteristic resulted in premature failure.					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
4.3	Insulation Voids	1. Perform tap test on bar 2. Section Bar and perform visual exam of insulation at fault for voids	Verify lapping configurations conform with drawings (Siemens) Insulation is free from voids	Some void areas were noted during tap testing, including areas around fault area. This was considered inconclusive due to the mechanical armor layer applied to the end arm areas where the fault was located. Various sections of bar B10 (control sample) and B17 were polished and inspected visually and microscopically, including section of bar on either side of the faulted area sample. Insulation was well consolidated and No substantive voids were noted in any of the samples inspected.	Insulation voids is refuted.	Some minor delamination in ICP (2 lapped layers of conductive tape) was apparent which explains some of the hollow indications from tap testing. Condition is benign due to conductivity of ICP layer and not unusual for in service stator bars.

4.0	**Failure Process # 4 – Stator Bar Configuration** Description: The construction of the bar does not conform to design specifications. Loss of margin to a critical design characteristic resulted in premature failure.					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
4.4	Material Properties	Sample insulation adjacent to fault location for test 1. Tensile test 2. Glass transition temperature 3. Burnout test to measure % organics 4. Soxhlet extraction to separate solids from insulation	Tensile test requirement: 5,000psi minimum for new coils Glass transition temperature requirement: 70C minimum for new coils % Organics requirement: 18-28% for new coils Soxhlet extraction requirement: 2.5% maximum for new coils Above test results will also be compared to the non-faulted bar	Samples from bars B10 (control) and B17 were subjected to all material tests.[D38] All samples passed Tensile test with significant margin with mean peak stress of 21276.7 psi 113.7C Glass Transition temperature was measured for B17 insulation sample is within expected value. All burn-out test insulation samples passed requirements for organic content All soxhlet extraction samples tested less than 2% unpolymerized content	The cause is refuted. Satisfactory test of various insulation samples demonstrates acceptable insulation material properties.	

4.0	**Failure Process # 4 – Stator Bar Configuration** Description: The construction of the bar does not conform to design specifications. Loss of margin to a critical design characteristic resulted in premature failure.					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
4.5	Bar Shape / Construction	Verify Bar dimensions within expectations.	Consistent along length of bar and within Siemens specification	There were no pronounced indentations or high spots on the coils. 5 measurements were taken of the height and width in the slot portion of the bars. The results were all within the tolerance for these coils.[D38]	The shape and construction of the bar did not play a role in the failure and is refuted.	

5.0	Failure Process # 5 – Ground to Stator Slot Coupler					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
5.0	Ground to Stator slot Coupler	Inspect Stator Slot Coupler Wiring Perform insulation resistance test at slot coupler	No evidence of wear or damage to insulation along SSC wiring path in stator. Low voltage IR demonstrates Slot coupler is not grounded to shield	Fault is located on the end arm adjacent to location of SSC wiring. Inspection of the wiring and location provides no indication this was involved in the fault. Insulation under the SSC wire banding is intact. [O3,D38] Testing of the SSC removed from Slot 17 demonstrates that the device is intact with acceptable insulation resistance. [D38]	This cause is refuted. There is no evidence the SSC device or its wiring was involved in or could have contributed to the fault.	

6.0	Failure Process # 6 – Crack in Insulation					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
	Crack in Insulation	Determine if cracking is present in stator bar insulation. 1. Non Destructive CT exam of bar 2. Visual and Microscopic Exam of fault area surface 3. Section Bar and perform Microscopic Examination of insulation at fault	Insulation is free from crack indications	No evidence for cracking in the ground wall insulation has been observed from visual and microscopic examination. The CT exam did not reveal any cracking.	All failure processes for cracking damage are refuted. No other evidence supporting cracking has been noted. This failure mode is refuted.	
6.1	Cracking during Installation/ Rewind	Review installation history / Siemens PCMs (internal records) for anomalies	No significant non-conformance with accepted installation practices	The generator winding activities were documented. Review of minor damage to bars in slot #35 and #42 were noted. The assessment and repair was documented in the Siemens PCM process. No report of damage to B17 was noted [D23,D41]	This cause is refuted. No evidence of cracking during installation was noted.	Passed High Potential Tests during installation which general demonstrates no cracking in the insulation.

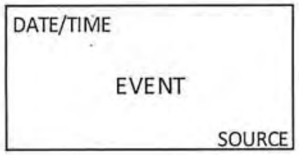
6.0	Failure Process # 6 – Crack in Insulation					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
6.2	Close in Short Circuit event or out of phase synchronization	Review generator operating history	No significant events identified since startup from SL1-24 after rewind	St Lucie Unit 1 did not have any valid generator relay or lockout trips during this period and notable grid disturbances were identified. Unit 1 did have an Inadvertent Energization lockout that occurred 8/21/2016, however the lockout was caused by a wiring issue and not a valid trip condition for the generator [D42]	Cracking due to a short circuit or out of phase event is refuted.	
6.3	Crack in operation due to thermal expansion	Evaluate insulation physical properties: exam and testing as described in 4.2.4 Compare properties of bottom 17 stator bar with other in service bars from generator as control samples	See 4.2.4	Samples from bars B10 (control) and B17 were subjected to all material tests. All testing results were satisfactory. Additionally, no cracking of the bar at the location of the fault has been observed from visual and microscopic examination of the surface and sections of B17. [D38]	Cracking due to thermal expansion is refuted.	

6.0	Failure Process # 6 – Crack in Insulation					
	CAUSE	VERIFICATION	EXPECTED / NORMAL	ACTUAL	CONCLUSION	NOTES
6.4	Delamination / Transverse cracking between layers	Perform visual examination of bar for delamination of insulation Inspect sectioned bar: exam and testing as described in 4.3 and 4.4	See 4.3 and 4.4	There are no signs of delamination in the insulation either from inspection of the surface surrounding the fault location or from inspection of sections from the bar. Testing results from all insulation samples are satisfactory.	Delamination between insulation layers is refuted.	

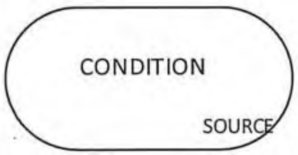
7.0	**Failure Process # 7 – Electrical Damage to Stator Bar Insulation** Description: Excessive electrical stress results in current flow on, or in, the ground wall insulation that thermally damages and carbonizes the organic constituents of the insulation. The resulting carbon track forms a conductive path along or through the insulation between the stator conductor and a ground.					
	CAUSE	**VERIFICATION**	**EXPECTED / NORMAL**	**ACTUAL**	**CONCLUSION**	**NOTES**
7.1	Partial Discharge / Corona	Determine estimated maximum void size for partial discharge based on voltage stress applied to insulation of B17 in service Inspect fault location for evidence of partial discharges.	Voltage across any voids or spaces in bar construction is insufficient to ionize H2 cooling gas resulting in PD activity. No evidence of carbonized voids and tracking indicating PD in insulation at fault location.	Fault is located on the turbine end arm of B17. Voltage stress on the ground wall insulation at this location is less than 3000Vac. PD is precluded as this is below the ionization voltage for the H2 cooling gas [D20,D38] The fault location does indicate some carbonization which follows the path of the fault current through the OCP along the bar to ground. This is attributed to the fault current after the insulation was breached. There is no internal tracking or any evidence of the fault following a path along the half lapped layers in the insulation as would be expected [D38]	This cause is refuted. PD at voltage below 3000Vac is unlikely in any machine. Pressurization in the St Lucie machine increases H2 ionization voltage such that PD could not occur at this location.	

7.0	**Failure Process # 7 – Electrical Damage to Stator Bar Insulation** Description: Excessive electrical stress results in current flow on, or in, the ground wall insulation that thermally damages and carbonizes the organic constituents of the insulation. The resulting carbon track forms a conductive path along or through the insulation between the stator conductor and a ground.					
7.2	Surface Tracking	Perform visual examination of bar surface insulation for evidence of tracking. Insulation Resistance test of cone pad sample [Turkey Point OE]	No evidence of carbon deposits, treeing formations or other indications of electrical tracking between the bar ends and the ECP/OCP layers or any adjacent surfaces to ground. Cone Pad material sample exceeds 1000 MΩ/in2 to refute condition similar to Turkey Point	No evidence of tracking was identified on B17. The fault was located at a location in the end arm in the OCP layer region, which contradicts any surface tracking due to this layer being conductive. Cone pad material was tested and found acceptable. The insulation resistance was 23.8GΩ at 5000Vdc	Surface Tracking is refuted.	Turkey Point OE on conductive cone pad material that resulted in failed high potential testing. St Lucie passed initial high potential testing after rewind

SYMBOL KEY

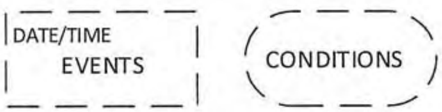


EVENTS - Who did what? Where? When?



CONDITIONS - Background Factors, Influences, Environment

RELATIONSHIPS



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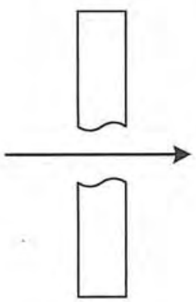
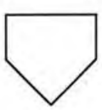


FAILED BARRIER



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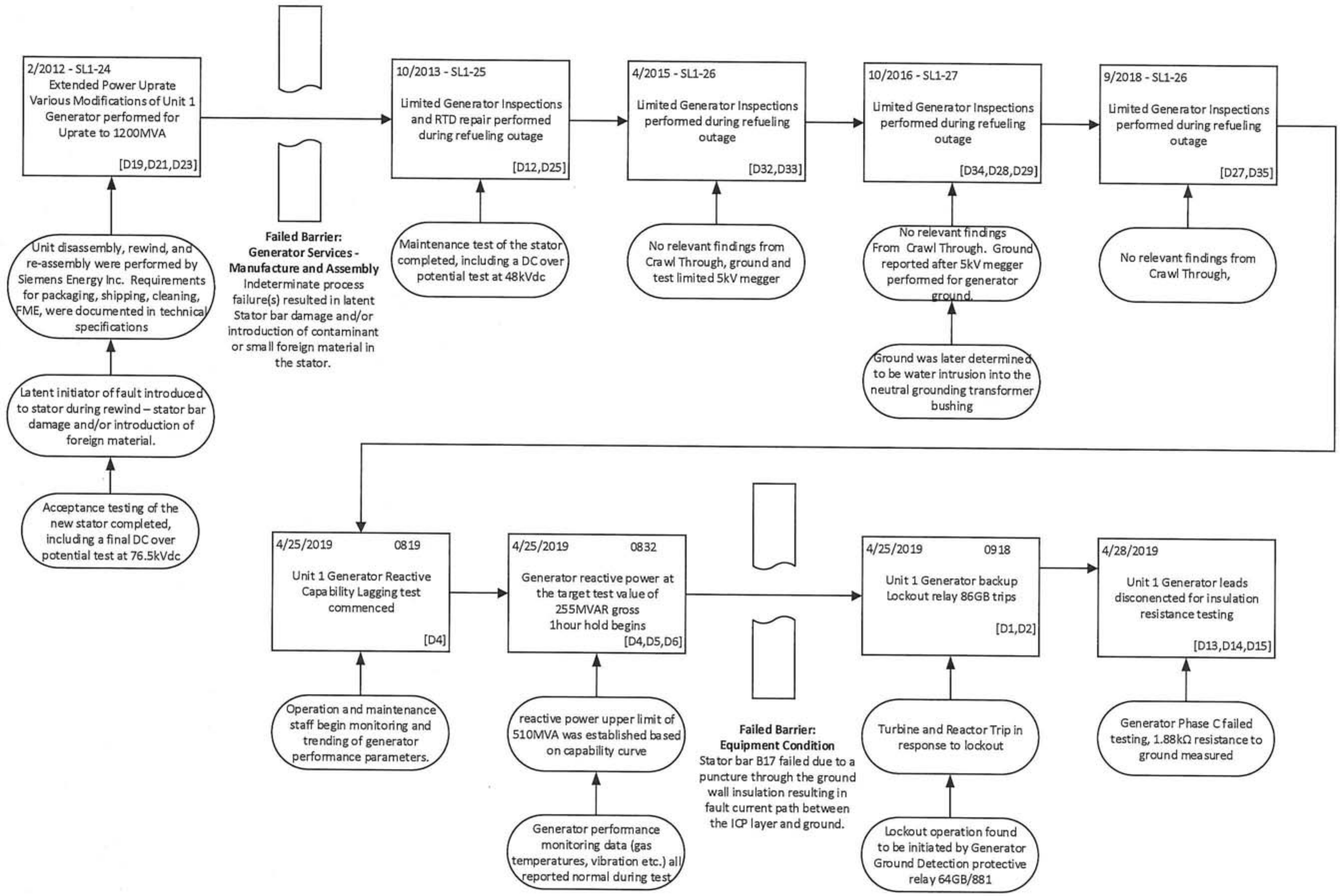

2/2012 - SL1-24
Extended Power Uprate
Various Modifications of Unit 1 Generator performed for Uprate to 1200MVA
[D19,D21,D23]
Unit disassembly, rewind, and re-assembly were performed by Siemens Energy Inc. Requirements for packaging, shipping, cleaning, FME, were documented in technical specifications
Latent initiator of fault introduced to stator during rewind – stator bar damage and/or introduction of foreign material.
Acceptance testing of the new stator completed, including a final DC over potential test at 76.5kVdc
Failed Barrier:
Generator Services - Manufacture and Assembly
Indeterminate process failure(s) resulted in latent Stator bar damage and/or introduction of contaminant or small foreign material in the stator.
10/2013 - SL1-25
Limited Generator Inspections and RTD repair performed during refueling outage
[D12,D25]
Maintenance test of the stator completed, including a DC over potential test at 48kVdc
4/2015 - SL1-26
Limited Generator Inspections performed during refueling outage
[D32,D33]
No relevant findings from Crawl Through, ground and test limited 5kV megger
10/2016 - SL1-27
Limited Generator Inspections performed during refueling outage
[D34,D28,D29]
No relevant findings From Crawl Through. Ground reported after 5kV megger performed for generator ground.
Ground was later determined to be water intrusion into the neutral grounding transformer bushing
9/2018 - SL1-26
Limited Generator Inspections performed during refueling outage
[D27,D35]
No relevant findings from Crawl Through,
4/25/2019 0819
Unit 1 Generator Reactive Capability Lagging test commenced
[D4]
Operation and maintenance staff begin monitoring and trending of generator performance parameters.
4/25/2019 0832
Generator reactive power at the target test value of 255MVAR gross
1hour hold begins
[D4,D5,D6]
reactive power upper limit of 510MVA was established based on capability curve
Generator performance monitoring data (gas temperatures, vibration etc.) all reported normal during test
Failed Barrier:
Equipment Condition
Stator bar B17 failed due to a puncture through the ground wall insulation resulting in fault current path between the ICP layer and ground.
4/25/2019 0918
Unit 1 Generator backup Lockout relay 86GB trips
[D1,D2]
Turbine and Reactor Trip in response to lockout
Lockout operation found to be initiated by Generator Ground Detection protective relay 64GB/881
4/28/2019
Unit 1 Generator leads disconencted for insulation resistance testing
[D13,D14,D15]
Generator Phase C failed testing, 1.88kΩ resistance to ground measured

Exhibit No.: 2

Proffered by: Public Counsel

Short title: Staff Interrogatory 41 Response

Witness(s): FPL- Coffey

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 55
PARTY: OPC
DESCRIPTION: Coffey

<u>QUESTION</u>:
For the purpose of Interrogatory Numbers 41-42 and subparts, please refer to Original Sheet Number 6.202.021 of Florida Power & Light Company's GPIF Actual Unit Performance Data Schedule for April 2019, filed on May 20, 2019 (April Performance Report). Please answer the following:

The April Performance Report identifies that a full forced outage began at St. Lucie Unit 1 on April 25, 2019 ("Outage").

A. Please describe the "UEL Main Generator Ground Fault" that is referenced on Original Sheet Number 6.202.021 of the April Performance Report.
B. In easily understandable terms, please describe this Outage event, and the restoration work performed in order to return St. Lucie Unit 1 to full commercial service.
C. Please identify the date St. Lucie Unit 1 returned to service from this Outage event.
D. Please identify the total number of hours St. Lucie Unit 1 was unavailable due to this Outage event.
E. Please identify the Net Summer Capacity (NSC) for St. Lucie Unit 1.
F. Please describe the actions FPL took to serve its customers while this base load plant was not operating.
G. Please state the replacement power cost attributable to this Outage, and explain how this amount was calculated.
H. How did FPL recover the replacement power cost attributable to this Outage?
I. Please state the repair cost attributable to this Outage.
J. How will FPL recover the repair cost attributable to this Outage?

<u>RESPONSE</u>:

A. The unplanned energy loss (UEL) was a full forced outage that began on April 25, 2019 at 09:18 AM until the main generator was restored and placed back in service on June 21, 2019 at 01:11 AM. The duration was approximately 57 days.

   The event was initiated by a main generator ground fault. The ground fault activated protective circuits that automatically shut down the nuclear reactor and electrically isolated the main generator.

   The main generator could not be returned to service until all repairs were completed.

B. The outage activities began with electrical testing to identify the extent of main generator damage caused by the ground fault. The location of the damage was determined to be in the stator windings. Subsequent troubleshooting required the removal of the main generator rotor and disassembly of the stator. The repair required a full rewind of the generator. The repair took 49 days to complete which is a vendor record for the shortest ever unplanned generator rewind.

C. St. Lucie Unit 1 returned to service on June 21st at 01:11 AM.

D. St. Lucie Unit 1 was unavailable due to this outage event for approximately 1,360 hours. Power ascension to return to 100% power was approximately 34 hours.

E. St. Lucie Unit 1 Net Summer Capacity (NSC) is 981 MW.

F. While St. Lucie Unit 1 was not operating, FPL served its customers by utilizing available generation from the balance of its fleet. Additionally, as part of its normal day-to-day activities, FPL actively pursued and executed power purchases in the wholesale power market when market prices were lower than the cost of FPL's own generation.

G. Please see Attachment 1 to this Interrogatory.

H. FPL has not yet recovered the replacement power costs associated with this outage event. The replacement power costs are included in actual fuel costs for 2019 and will be recovered through FPL's fuel cost recovery clause factor to be effective commencing January 1, 2020.

I. The repair cost attributable to this outage was approximately $29 million.

J. Inspection and repair costs will be recovered through FPL's base rates.

Event Start	Event End	Seq. #	Event Title	MW Loss	Outage Hours	MWh Loss	Replacement Cost ($/MWh)	Replacement Cost ($)	SL1 Fuel Cost ($/MWh)	Nuclear Fuel Cost ($)	Net Replacement Cost ($)
4/25/2019 9:18	5/1/2019 0:00	1	U1 UEL Main Generator Ground Fault	981.00	134.70	132,141	$19.93	$2,633,304	$5.40	$714,188	$1,919,117
5/1/2019 0:00	6/1/2019 0:00	2		981.00	744.00	729,864	$19.25	$14,047,035	$5.40	$3,944,733	$10,102,302
6/1/2019 0:00	6/21/2019 1:11	3		981.00	481.18	472,041	$18.52	$8,739,971	$5.40	$2,551,263	$6,188,708
6/21/2019 1:11	6/22/2019 11:30	4	Power Ascension	336.72	34.32	11,555	$18.52	$213,946	$5.40	$62,452	$151,494
				Total	**1,394.20**	**1,345,600.66**		**$25,634,257**		**$7,272,636**	**$18,361,621**
											$316,080 /Day

April 2019 - A4 Data	
SL1 Fuel Cost	**SL1 Heat Rate**
0.52	10,357
SL1 $/MWh	
$5.405	

April 2019 - A3 Data								
Fuel	**MWh**	**% Mix**	**Fuel Cost $**	**$/MWh**	**Demand $**	**Rev. Fuel Cost $**	**$/MWh**	**WA $/MWh**
Heavy Oil	15,428	0.20%	$1,968,602	$127.60	$0	$1,968,602	$127.60	$0.26
Light Oil	6,830	0.09%	$1,001,213	$146.59	$0	$1,001,213	$146.59	$0.13
Coal	186,421	2.45%	$5,444,667	$29.21	$0	$5,444,667	$29.21	$0.72
Gas	7,405,223	97.26%	$219,361,512	$29.62	$76,045,902	$143,315,610	$19.35	$18.82
Total	**7,613,902**	**100.00%**	**$227,775,994**		**$76,045,902**	**$151,730,092**		**$19.93**

May 2019 - A3 Data								
Fuel	**MWh**	**% Mix**	**Fuel Cost $**	**$/MWh**	**Demand $**	**Rev. Fuel Cost $**	**$/MWh**	**WA $/MWh**
Heavy Oil	26,474	0.29%	$3,299,209	$124.62	$0	$3,299,209	$124.62	$0.36
Light Oil	7,266	0.08%	$899,256	$123.76	$0	$899,256	$123.76	$0.10
Coal	268,083	2.90%	$7,705,798	$28.74	$0	$7,705,798	$28.74	$0.83
Gas	8,939,365	96.73%	$243,296,912	$27.22	$77,344,351	$165,952,561	$18.56	$17.96
Total	**9,241,188**	**100.00%**	**$255,201,176**		**$77,344,351**	**$177,856,825**		**$19.25**

June 2019 - A3 Data								
Fuel	**MWh**	**% Mix**	**Fuel Cost $**	**$/MWh**	**Demand $**	**Rev. Fuel Cost $**	**$/MWh**	**WA $/MWh**
Heavy Oil	27,792	0.30%	$3,540,260	$127.38	$0	$3,540,260	$127.38	$0.38
Light Oil	9,113	0.10%	$1,283,074	$140.79	$0	$1,283,074	$140.79	$0.14
Coal	221,108	2.37%	$6,765,450	$30.60	$0	$6,765,450	$30.60	$0.72
Gas	9,086,126	97.24%	$237,476,593	$26.14	$76,055,970	$161,420,623	$17.77	$17.28
Total	**9,344,139**	**100.00%**	**$249,065,376**		**$76,055,970**	**$173,009,406**		**$18.52**

Exhibit No.: 3

Proffered by: Public Counsel

Short title: St. Lucie 1 Generator Ground Fault Analysis

Witness(s): FPL- Coffey

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 56
PARTY: OPC
DESCRIPTION: Coffey

St. Lucie 1 Generator Ground Fault Analysis

Gary Griffith, PGD Technical Services Leader

Randal Kerkes, Principal Technical Services Specialist

July 11th 2019

Agenda

St. Lucie 1 Generator Ground Fault

- **Executive Summary**
- **Fault Tree**
- **Siemens RCA Report**
  - Conclusion
  - Recommendations
- **EOSS**
  - Conclusion
  - Recommendations
- **Review of Forensic Analysis at Siemens Charlotte Innovation Lab**
  - Bottom Bar 17 Analysis
    - -- Picture of bar dissection with findings
    - -- Microscopic inspection of dissected bar specimens
    - -- Microscopic inspection of Insulation failure location
    - -- Review of Fourier-transform infrared spectroscopy (FTIR) data

Executive Summary

St. Lucie Unit 1 Generator Ground Fault

When & Where did it Occur:

On 4/25/2019 at 09:18, St. Lucie Unit 1 experienced a stator ground fault

Repair:

Complete Stator winding replacement

What is the pain:

EFOR of ~59 Days, from 4/25/2019 to 6/22/2019
Lost generation of 1,375,775 MWh

What happened: Undetected Stator Winding Insulation failure (stator ground fault)
Most probable cause “Magnetic Termite”

Operational Risk:

No change is recommended to operational or maintenance plans for the remaining Siemens rewound units (PSL2, PBN 1, PBN 2, PTN 3, PTN 4). Details below. Maintaining a spare winding is not economical

FPL

Bottom Bar 17 Forensic Analysis Report from Siemens

St. Lucie Unit 1 Generator Ground Fault

- **Siemens Forensic Analysis – yielded the following:**
  - Siemens RCA Report Pending

Bottom Bar 17 Forensic Analysis Report from FPL EOSS

St. Lucie Unit 1 Generator Ground Fault Analysis

- **Participated in Siemens Forensic analysis / testing**
  - Elimination of most common failure modes, see Fault Tree
  - Fault channel is straight through the insulation system starting at the top of the bar insulation down to the conducting surface, indicating a classic "Magnetic Termite" failure
  - Ferrous material was introduced during the on site rewind process or during coil manufacturing
  - Ferrous material no longer present after the fault
- **Siemens performed major stator frame and core work on PSL 1 during rewind in 2012**
  - Complete restack with extensive grinding and welding
  - PSL 1 only unit in NEE fleet with this extent of frame and core modification coincident with a rewind activity

FPL

Bottom Bar 17 Forensic Analysis Report from FPL EOSS (continued)

St. Lucie Unit 1 Generator Ground Fault Analysis

- **Additional Research - EPRI papers on "Magnetic Termite" failures with similar forensic evidence**
  - DTE Energy Fermi 2: GE Design (H2 In leakage to Stator Cooling Water)
  - Electrabel GDF Belgium Nuclear: Jeumont – Westinghouse Design (Stator Ground Fault)
- **Consulted with industry expert, Greg Stone (IEEE Fellow, IRIS Power)**
  - Agreed that "Magnetic Termite" is most likely failure mode
- **Based on the extent of core work performed during the 2012 rewind, the most likely root cause is an introduction of ferrous foreign material**

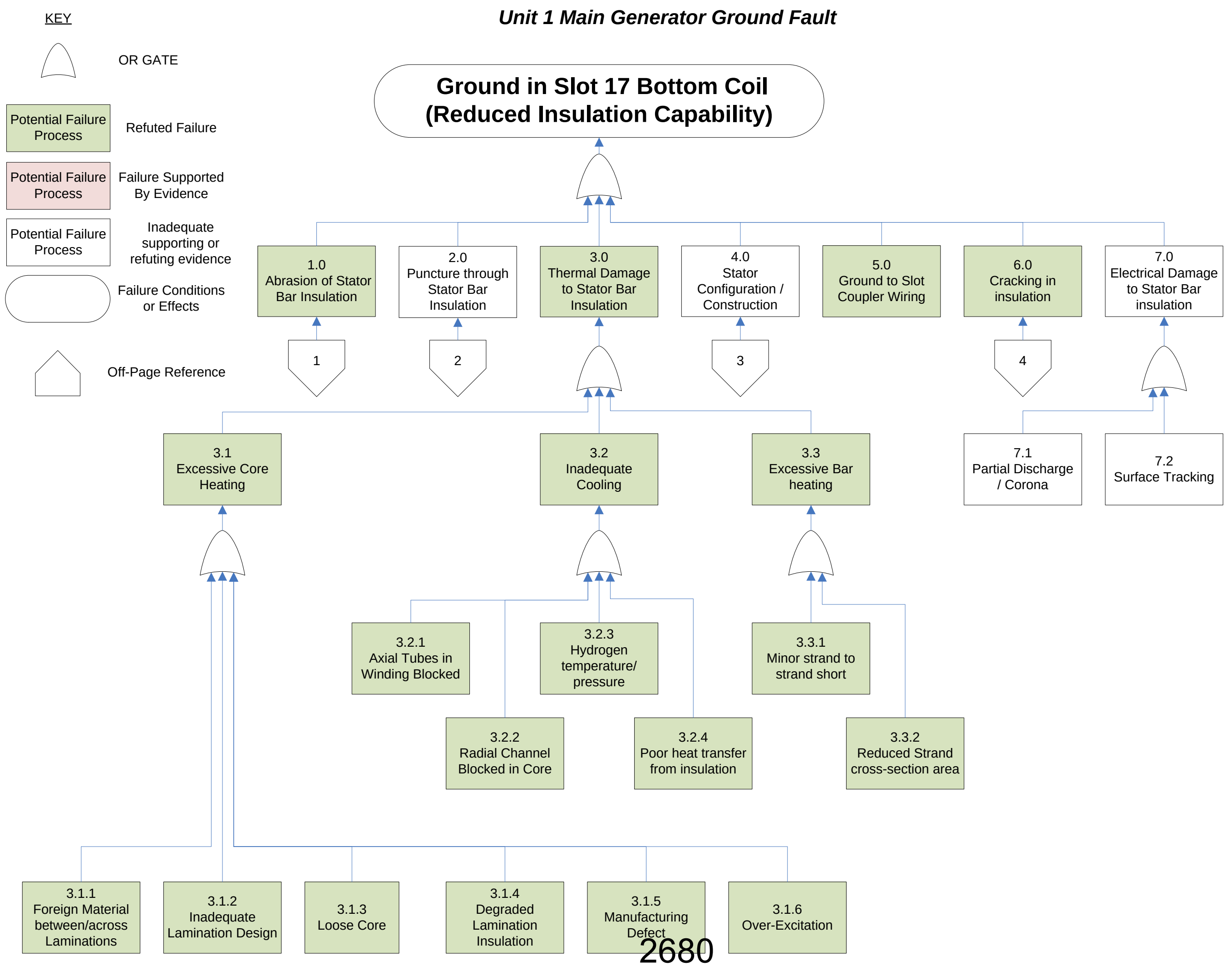
No definitive root cause was identified due to the damage at the failure location

2679

FPL

Fault Tree

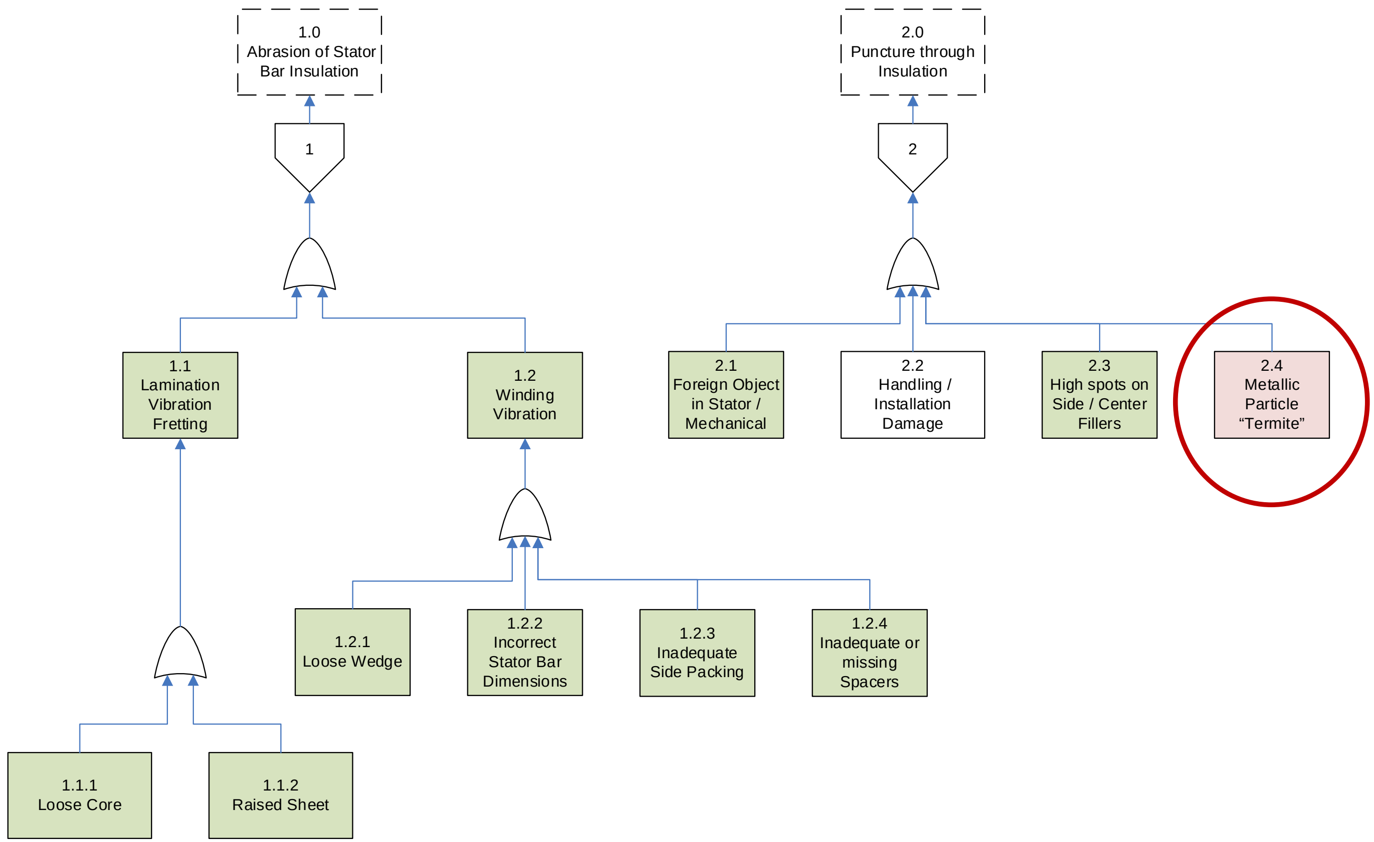
St. Lucie 1 Generator Ground Fault



2680

Fault Tree

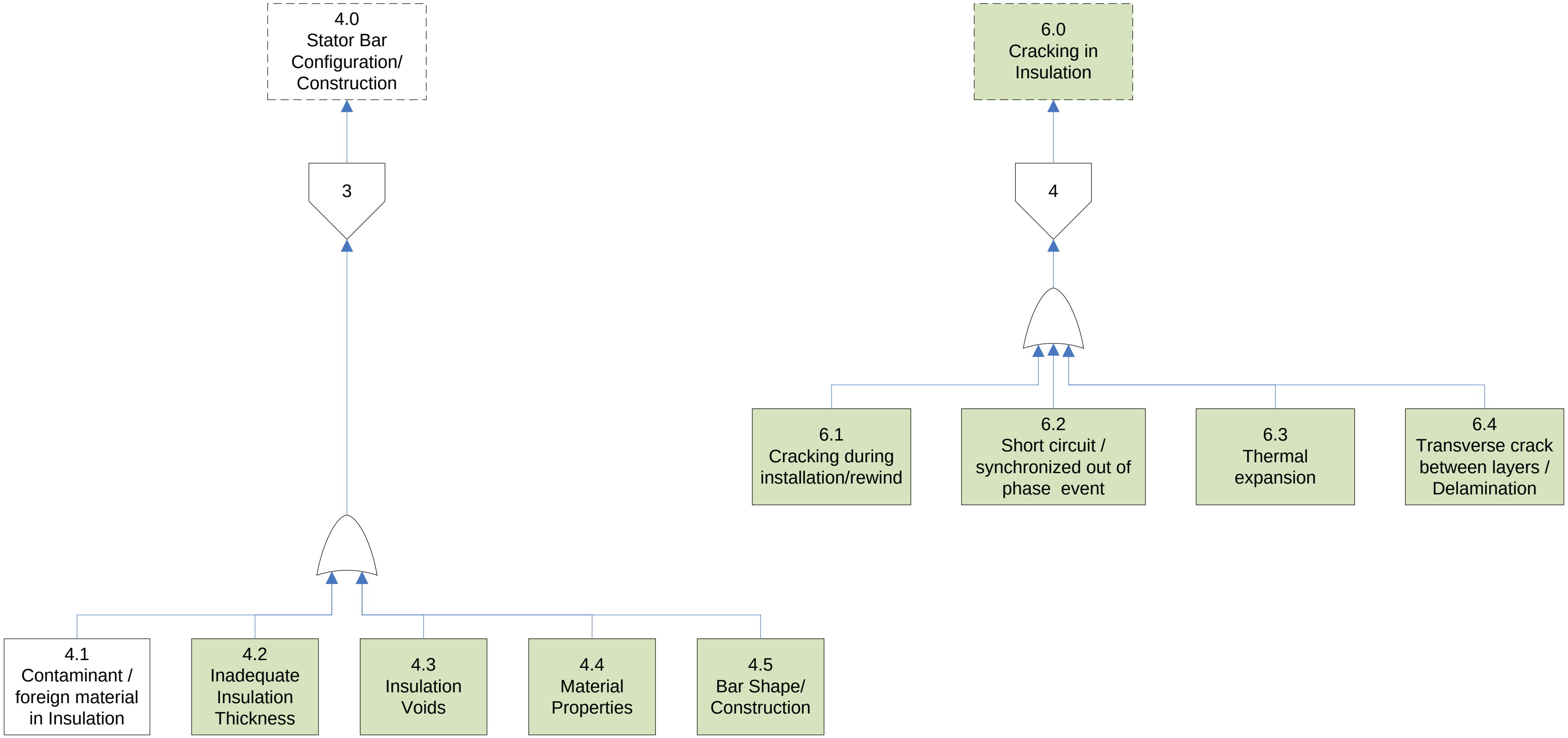
St. Lucie 1 Generator Ground Fault



By Elimination of possible failure modes the most probable and verified by 3rd party consultant is a "Magnetic Termite"

Fault Tree

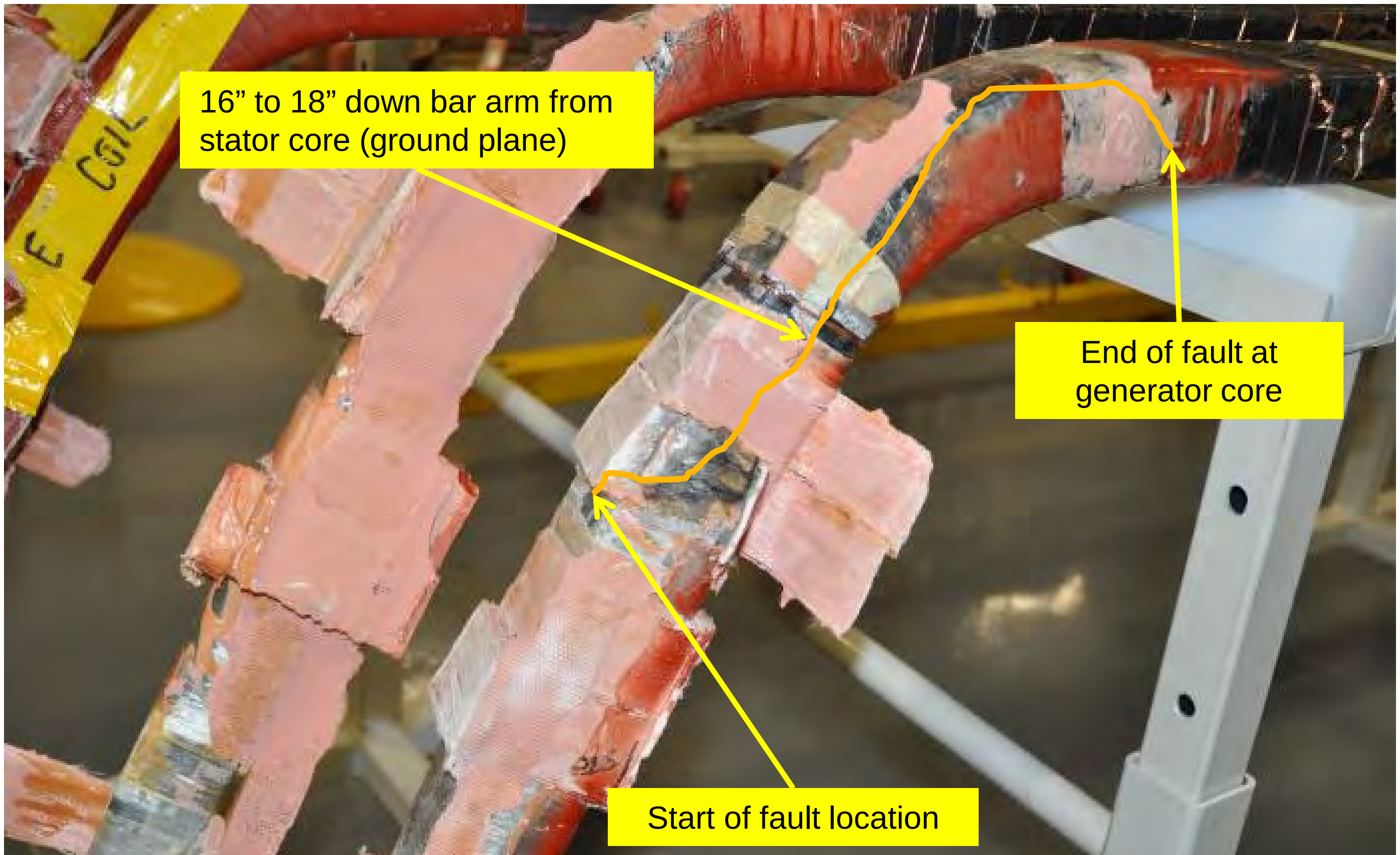
St. Lucie 1 Generator Ground Fault



2682

Review of Forensic Analysis at Siemens Charlotte Innovation Lab

St. Lucie 1 Generator Ground Fault Path



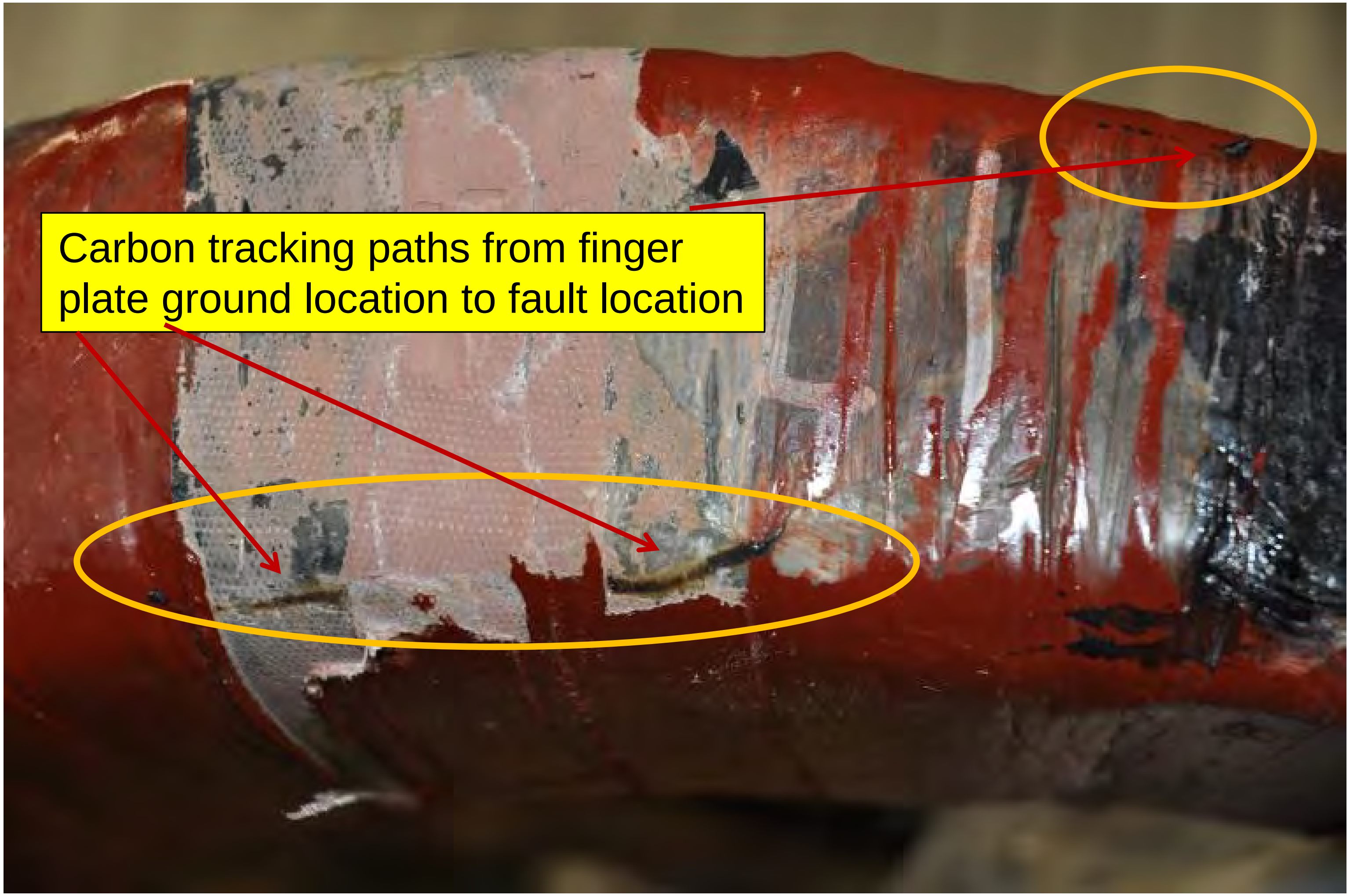
Fault Initiation at Endwinding Leading to Core Finger Plate

2683

FPL

Review of Forensic Analysis at Siemens Charlotte Innovation Lab

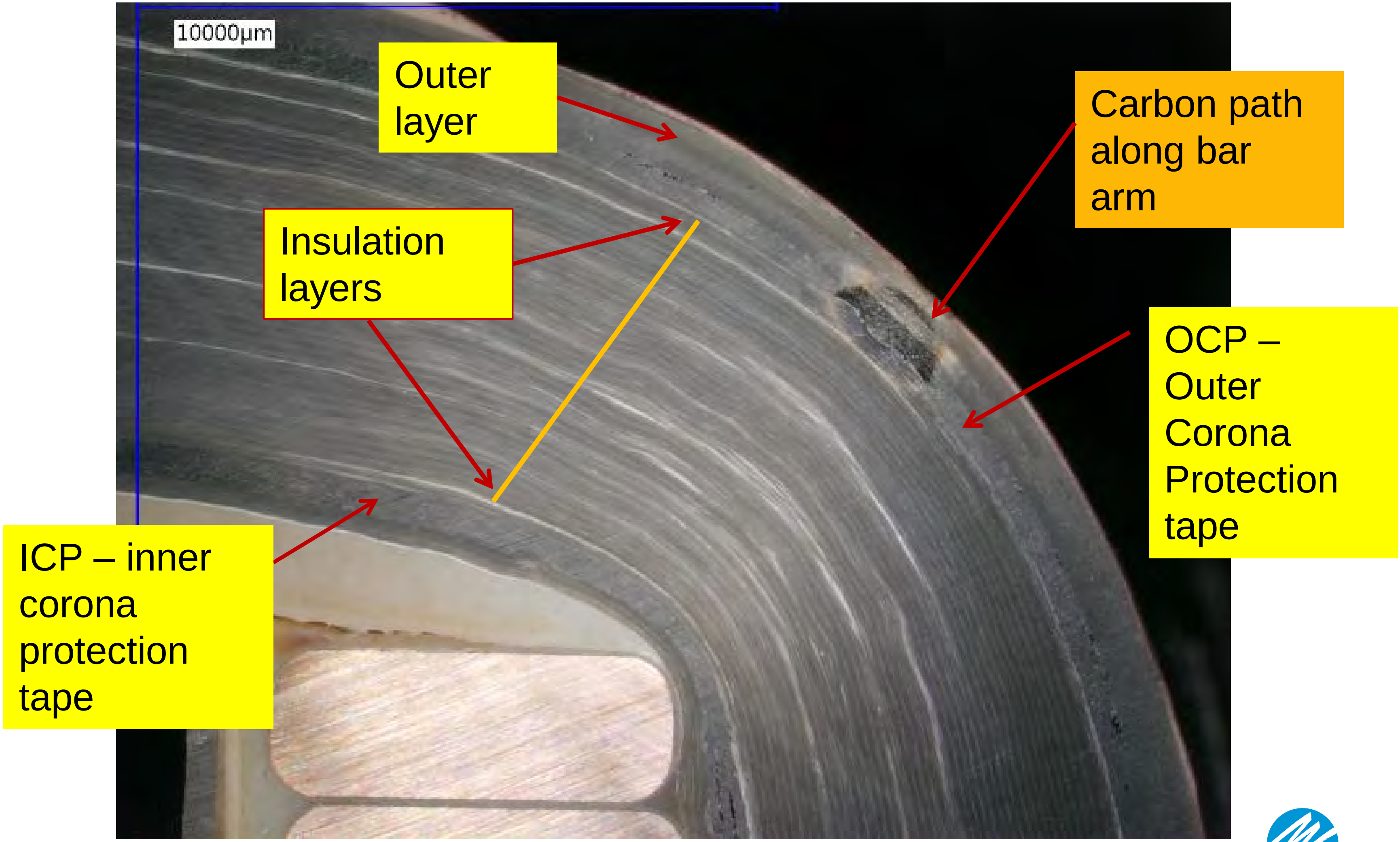
St. Lucie 1 Generator Ground Fault



2684

Review of Forensic Analysis at Siemens Charlotte Innovation Lab

St. Lucie 1 Generator Ground Fault

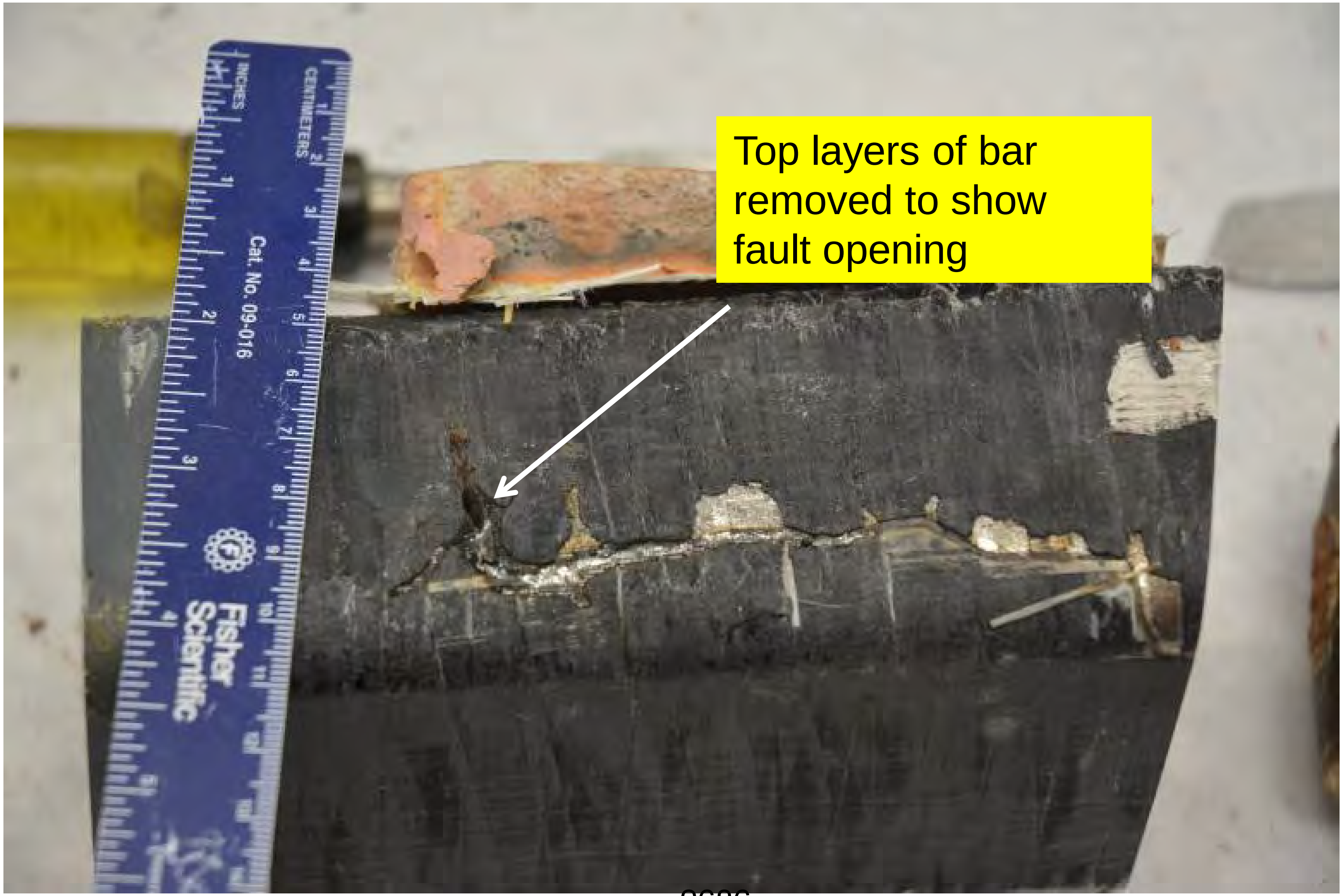


2685

FPL

Review of Forensic Analysis at Siemens Charlotte Innovation Lab

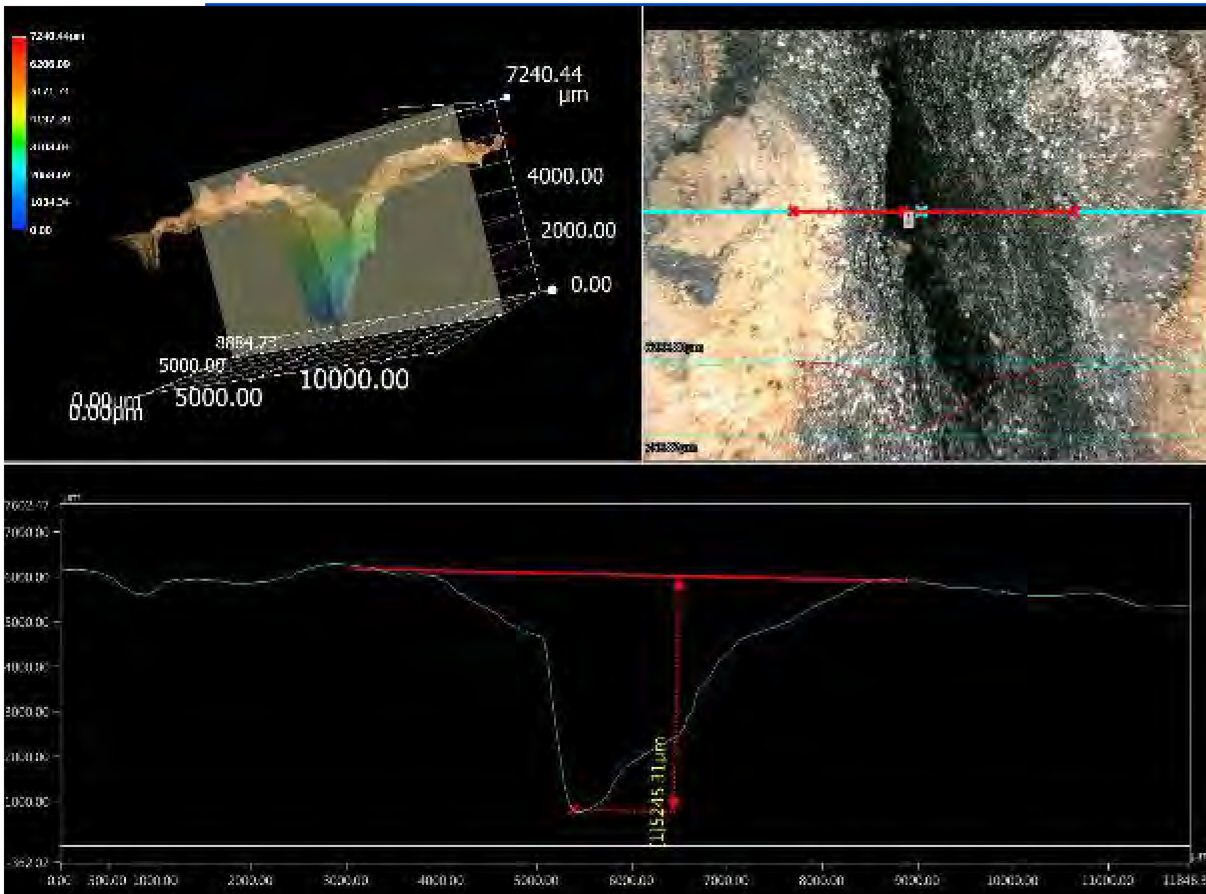
St. Lucie 1 Generator Ground Fault



2686

Review of Forensic Analysis at Siemens Charlotte Innovation Lab

St. Lucie 1 Generator Ground Fault



Failure straight down through insulation system

Failure mode characteristics of a Magnetic termite – 2.4 on refute matrix

Failure mode characteristics of a "Magnetic Termite" – 2.4 on fault tree
Magnetic Termite relatively long term failure mode

EOSS Conclusions

St. Lucie 1 Generator Ground Fault Summary

- **EOSS Analysis concludes the failure mode is a “Magnetic Termite”:**
  - Based on available evidence, the failure was caused by a “Magnetic Termite” introduced by a failure of FME process
  - PSL 1 only unit in NEE fleet with a complete core restack and extensive frame and core modifications coincident with a rewind
  - This is a know failure mode identified on two other units:
    - -- Electrabel, GDF Suez
    - -- DTE Energy
  - No known test / inspection to detect this failure mode
- **Recommendations**
  - No change to current NEE operational or maintenance plans
  - Ensure strict adherence to FME process during generator work

FME process adherence is critical to long term generator reliability

Appendix

Inspection of bottom bars is extremely difficult

<u>This is a Sanford STG which has the same endwinding support design as PSL-1</u>

There is no practical method to inspect many areas of the winding for 'termite' activity, most of which may be under the top layer of the bar and thus invisible even if it was possible to inspect the whole winding

2690

FPL

Exerts from EPRI Papers – Support Evidence

Fermi 2 – Issue manifested as an In leakage of H_2 Stator Cooling Water

DTE Energy

Fan baffle and cruciform removed

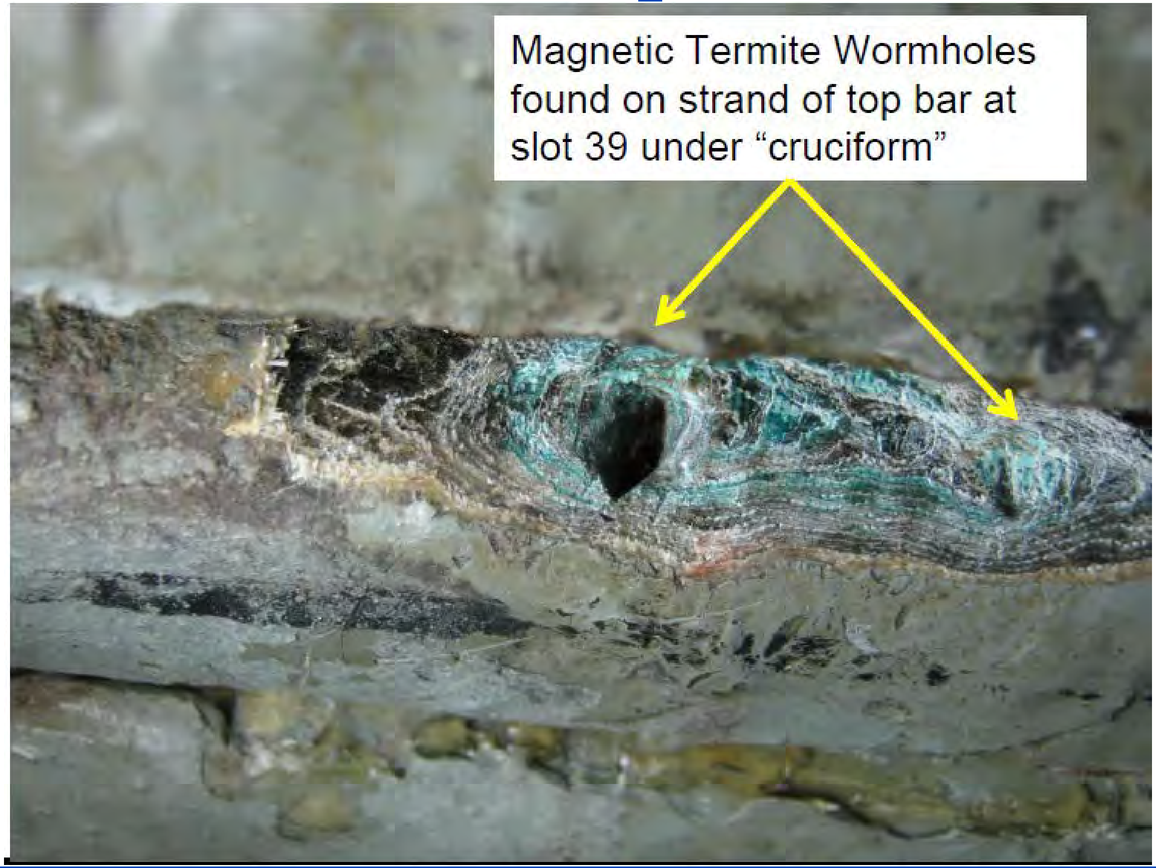
Failure under end winding supports similar to St. Lucie Unit 1

2691

FPL

Exerts from EPRI Papers – Support Evidence

Fermi 2 – In leakage of H_2 Stator Cooling Water



Failure opening in insulation similar to St. Lucie Unit 1

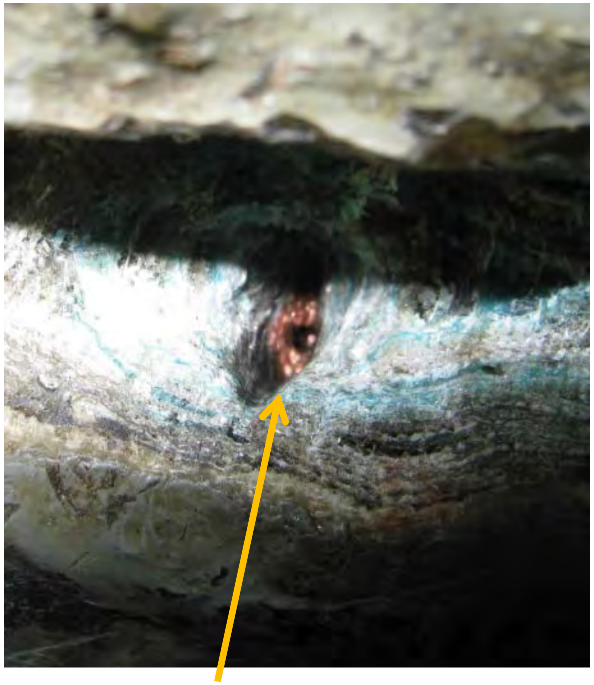
2692

FPL

Excerpts from EPRI Papers – Supporting Evidence

Fermi 2 – In leakage of H_2 Stator Cooling Water

Particle is approx. 2.39 X 0.613 mm



Magnetic Termite – worm hole

Failure opening in insulation similar to St. Lucie Unit 1 but, since there was no electrical fault, the particle was recovered

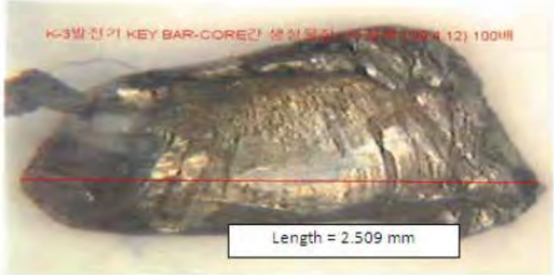
Excerpts from EPRI Papers – Supporting Evidence

Fermi 2 – In leakage of H_2 Stator Cooling Water

DTE Energy

Termites found at Kori

Particles from KoRi generator [lo carbon steel]



Magnetic termites failure mode documentation

Excerpts from EPRI Papers – Supporting Evidence

Electrabel GDF Suez – Belgian Nuclear Unit

Bottom bar failure

Excerpts from EPRI Papers – Supporting Evidence

Electrabel GDF Suez – Belgian Nuclear Unit

Failure mode identical to St. Lucie Unit 1 – tracking from insulation opening to ground over stator bar insulation

Excerpts from EPRI Papers – Supporting Evidence

Electrabel GDF Suez – Belgian Nuclear Unit

Electrabel GDF SUEZ

RCA - BAR AUTOPSY BY LABORELEC

- General condition of insulation good given the age of the machine (37Y)
- Correct alignment and impregnation of insulation layers
- Breakdown channel goes straight through insulation layers
- No traces of partial discharge activity between insulation layers
- No foreign materials found

12

Exact failure mode as St. Lucie Unit 1

2697

FPL

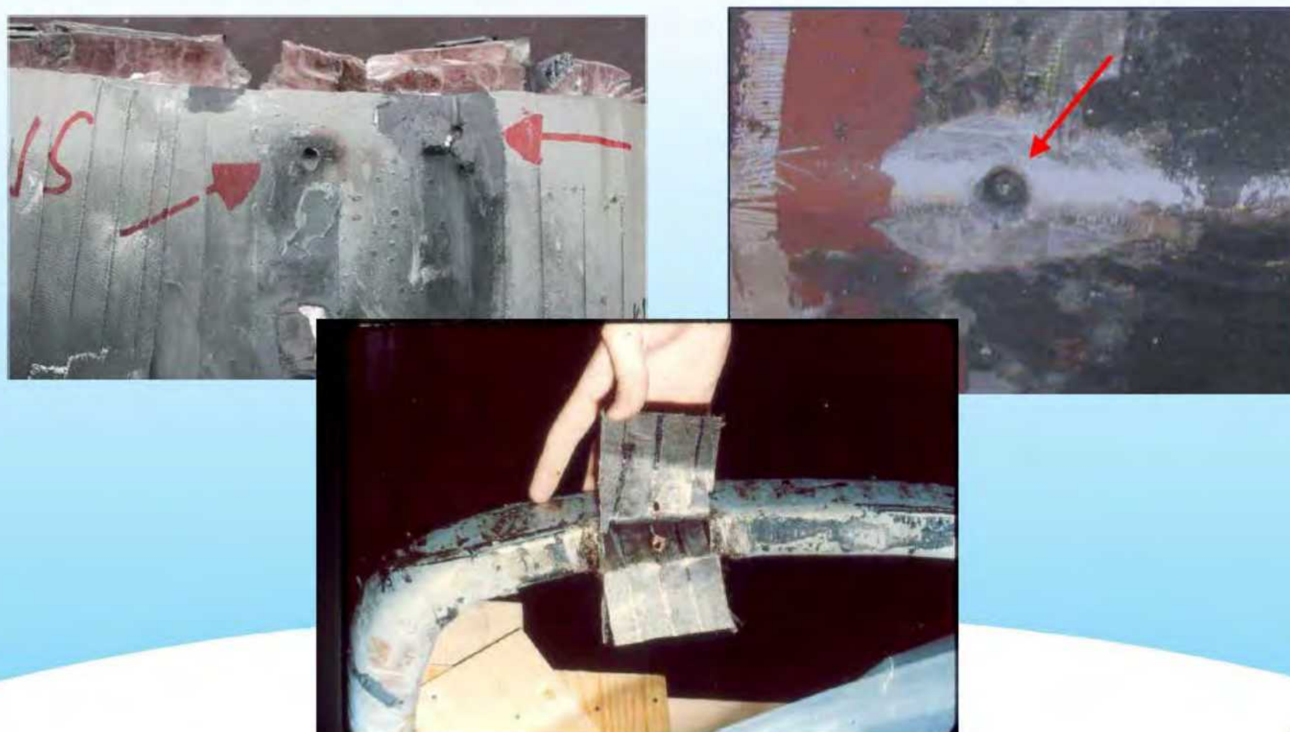
Excerpts from EPRI Papers – Supporting Evidence

Electrabel GDF Suez – Belgian Nuclear Unit

Electrabel
GDF SUEZ

RCA – EXTERNAL CONSULTATION

- Other examples of insulation failure caused by magnetic termites



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02698

Excerpts from EPRI Papers – Supporting Evidence

Electrabel GDF Suez – Belgium Nuclear Unit

Electrabel
GDF SUEZ

RCA – EXTERNAL CONSULTATION

- **Different parties were consulted to present their hypotheses based on pictures provided, discussion and lab visits.**
    - Thomas Hillfer (Alstom Birr, head of insulation competence center)
    - Gregg Stone (IEEE fellow, IRIS power)
    - Stefan Lanz (freelancer, former head of insulation CC Alstom/ABB Birr)
    - Siemens-Westinghouse engineering
- Independently all 4 experts pointed out the presence of a **'magnetic termite'** as the most probable cause of the defect.
- Magnetic termite = **metallic object** (1-2 mm) trapped locally, wearing out the insulation due to a combined effect of magnetic attraction (field around bar) and 50 Hz vibration due to eddy currents induced.
- **Origin** of the particle is **unknown**.
- **Propagation time** is **not clear**: according to some experts it can take many 10.000 OH, according to others 1 or 2 years can already be enough.

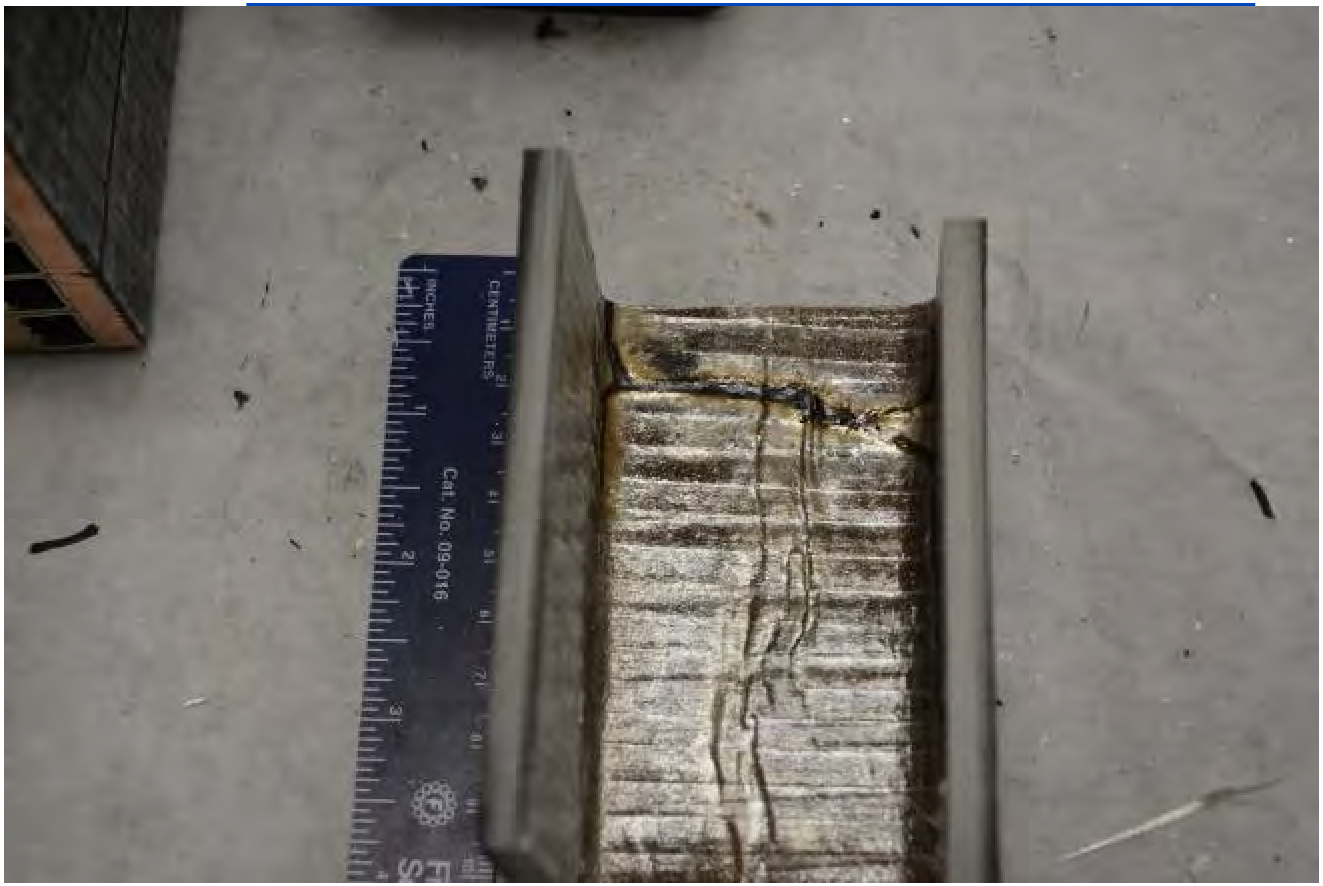
Review of Forensic Analysis at Siemens Charlotte Innovation Lab

St. Lucie Generator Ground Fault

Separated insulation from ICP layer – Forensic process evaluating specimen for failure mode – none NOTED AT THIS TIME

Review of Forensic Analysis at Siemens Charlotte Innovation Lab

St. Lucie Generator Ground Fault



FAULT OPENING STRAIGT DOWN DID NOT FOLLOW TAPE EDGS AS A NORMAL FAILURE MODE WOULD

Review of Forensic Analysis at Siemens Charlotte Innovation Lab

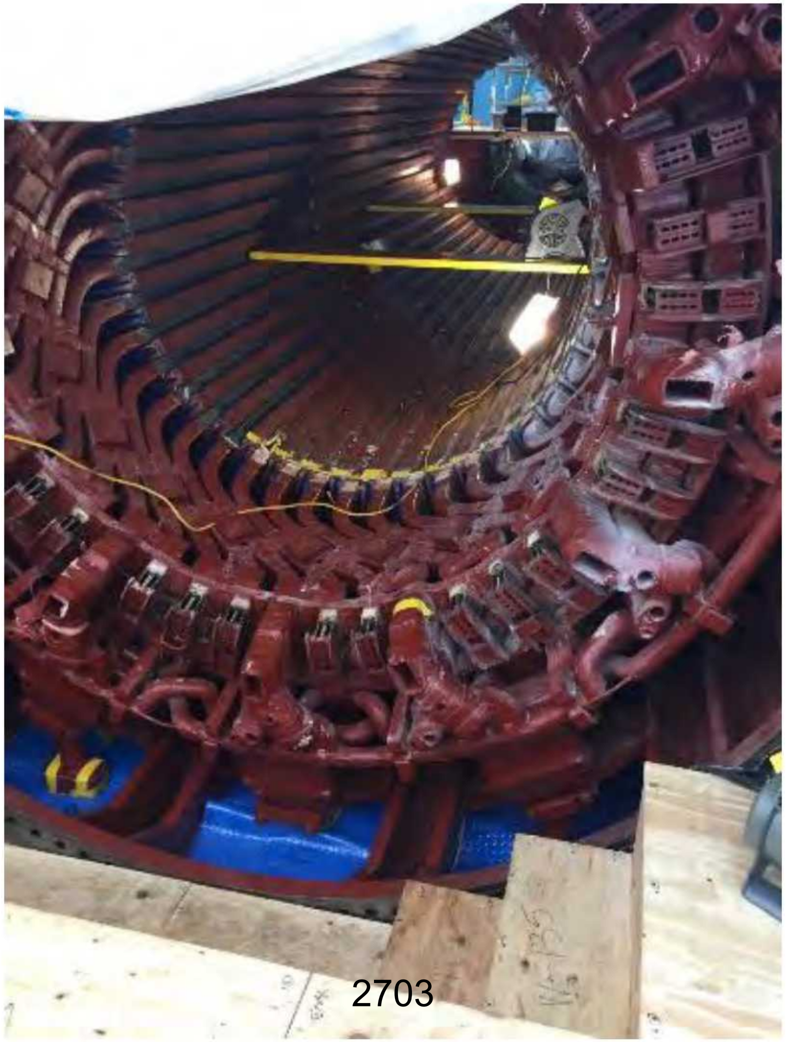
St. Lucie Generator Ground Fault

Discharge site to ground – Stator Core Finger Plate

2702

Review of Forensic Analysis at Siemens Charlotte Innovation Lab

St. Lucie 1 Generator Coil Removal



2703

02703

Review of Forensic Analysis at Siemens Charlotte Innovation Lab

St. Lucie 1 Generator Coil Removal

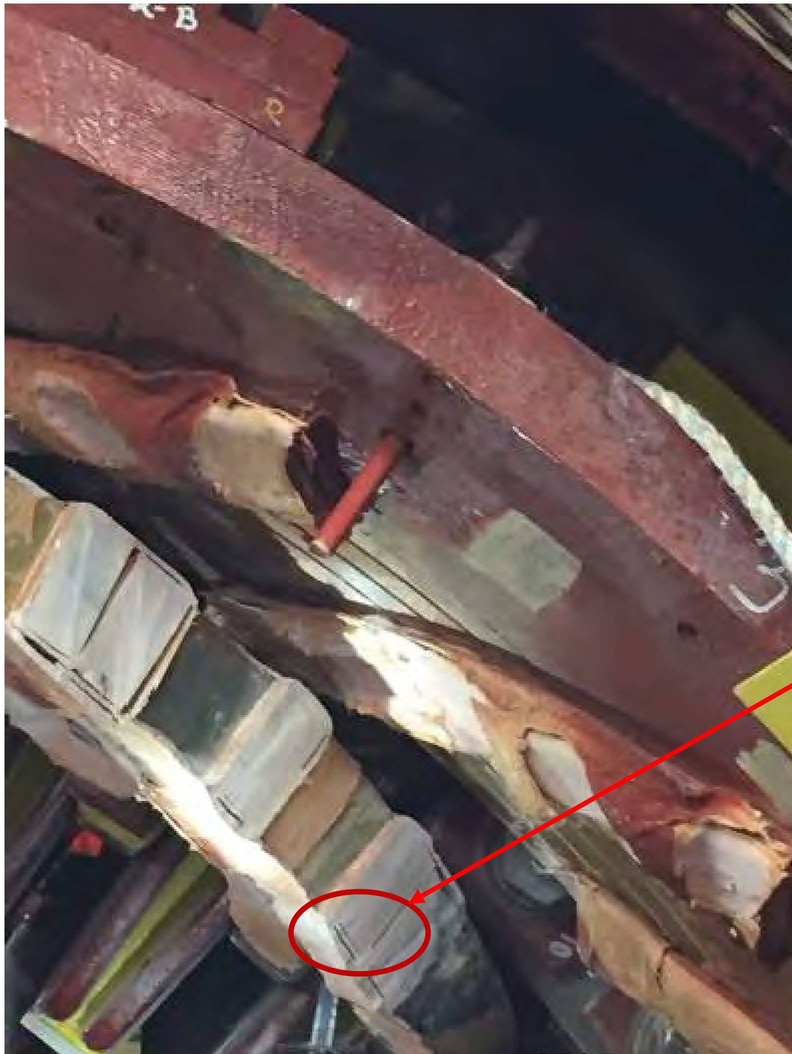
2704

02704

FPL

Review of Forensic Analysis at Siemens Charlotte Innovation Lab

St. Lucie Generator Ground Fault



Extraction of Bottom Bar 17 - Fault location under blocking Hidden from view by blocking

2705

EXHIBIT NOT ENTERED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 57
PARTY: OPC
DESCRIPTION: Coffey

EXHIBIT NOT ENTERED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 58
PARTY: OPC
DESCRIPTION: Coffey
2707

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20200001-EI

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE WITH
GENERATING PERFORMANCE
INCENTIVE FACTOR.
_____________________________/

PROCEEDINGS: PREHEARING CONFERENCE

COMMISSIONERS
PARTICIPATING: COMMISSIONER ANDREW GILES FAY
PREHEARING OFFICER

DATE: Monday, October 26, 2020

TIME: Commenced: 1:30 p.m.
Concluded: 2:52 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: ANDREA KOMARIDIS WRAY
Court Reporter and
Notary Public in and for
the State of Florida at Large

PREMIER REPORTING
114 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
(850) 894-0828

APPEARANCES:

MATTHEW R. BERNIER, ESQUIRE, 106 East College Avenue, Suite 800, Tallahassee, Florida 32301-7740; and DIANNE M. TRIPLETT, ESQUIRE, 299 First Avenue North, St. Petersburg, Florida 33701, appearing on behalf of Duke Energy Florida, LLC.

MARIA J. MONCADA, WADE R. LITCHFIELD, and DAVID M. LEE, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

BETH KEATING, ESQUIRE, Gunster, Yoakley & Stewart, P.A., 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1839, appearing on behalf of Florida Public Utilities Company.

RUSSELL A. BADDERS, ESQUIRE, One Energy Place, Pensacola, Florida 32520-0100; MARIA J. MONCADA, ESQUIRE, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Gulf Power Company.

JAMES D. BEASLEY, J. JEFFRY WAHLEN, and MALCOLM N. MEANS, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

APPEARANCES (CONTINUED):

J.R. KELLY, PUBLIC COUNSEL; CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL; and PATRICIA A. CHRISTENSEN, STEPHANIE A. MORSE, A. MIREILLE FALL-FRY, and THOMAS (TAD) DAVID, , ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

JON C. MOYLE, JR., and KAREN A. PUTNAL, ESQUIRES, Moyle Law Firm, P.A., The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

JAMES W. BREW and LAURA WYNN BAKER, ESQUIRES, Stone Mattheis Xenopoulos & Brew, PC, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington, DC 20007, appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate - White Springs.

SUZANNE BROWNLESS, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

APPEARANCES (CONTINUED):

KEITH HETRICK, GENERAL COUNSEL; MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

P R O C E E D I N G S

COMMISSIONER FAY: Thank you for waiting patiently, Ms. Brownless. You've got the end.

We've already read the notice for this docket. So, preliminary matters?

MS. BROWNLESS: Yes, sir, but not at this time.

COMMISSIONER FAY: Okay. Similar to the other dockets, we'll move through the draft prehearing order. Please interject if there's something you'd like to speak on.

We will start with the Sections I, II, and III, case background, conduct of proceedings, and jurisdiction.

Section IV, procedure for handling confidential information.

Section V, prefiled testimony and exhibits, witnesses.

MS. BROWNLESS: Yes, sir. At this time, a time will need to be set for witness summaries.

COMMISSIONER FAY: And I -- it's pretty standard for the Commission to set three minutes. So, without any objection, we -- I would set that in the hearing -- in the prehearing order.

MS. BROWNLESS: Thank you.

COMMISSIONER FAY: Order of witnesses.

MS. BROWNLESS: Yes, sir. We are not aware of any changes in the order of witnesses.

COMMISSIONER FAY: Okay. Great. And can we address which witnesses could be excused for this?

MS. BROWNLESS: Yes, sir. My understanding is that parties have agreed that all Gulf and TECO witnesses -- and that would be Mr. Hume, Rote for Gulf, and Sizemore, Cain, Smith, and Heisey for TECO, as well as staff witness Dobiac can be excused, their testimony inserted into the record as though read, and their exhibits entered into the record. This is reflected in the draft prehearing order circulated to the parties.

We would like to confirm with the parties at this time that they agree.

COMMISSIONER FAY: Well, I guess, we'll start with Gulf. Can you confirm the stipulated witnesses -- excuse me -- those excused witnesses.

MS. MONCADA: Gulf is in agreement. This is Maria Moncada. Thank you.

COMMISSIONER FAY: Great. Thank you.

And TECO?

MR. MEANS: Tampa Electric is in agreement. Thank you.

COMMISSIONER FAY: Okay. Great.

MS. BROWNLESS: Also, parties (technical interruption) --

COMMISSIONER FAY: Yeah, and just -- just to clarify, additional to any -- any other intervenors are -- this would be the time to object if -- if the -- if you had an issue with the witness being excused.

MS. CHRISTENSEN: Yeah, this is Patti Christensen with OPC. No objection to the stipulation of the witness testimony by the parties. I'm willing -- willing to accommodate that stipulation.

COMMISSIONER FAY: Okay. Great. Thank you.

Ms. Brownless, so that -- will that leave us here with any other witnesses that could be excused?

MS. BROWNLESS: Yes. We will, of course, check with the Commissioners to make sure Commissioners have no questions.

As to other witnesses, parties are working on stipulations at this time, and may result in other witnesses being excused. We think there may be agreement that all FP&L witnesses, with the exception of Witness Coffey, can be stipulated.

And that would be Witnesses Deaton, Yupp --

MS. HELTON: Commissioner and Ms. Brownless -- I'm sorry. The court reporter is asking me to remind everyone to speak up a little bit. She's having a hard time hearing everyone.

COMMISSIONER FAY: Got to lean into these new mics.

MS. BROWNLESS: Is that better?

COMMISSIONER FAY: I -- we'll -- we'll verify. Maybe just speak up just a little bit, Ms. --

MS. BROWNLESS: Okay. I'll go back.

COMMISSIONER FAY: -- Brownless. Thank you.

MS. BROWNLESS: Parties are working on stipulations at this time which may result in other witnesses being excused. I think there may be agreement that all FP&L witnesses, with the exception of Witness Coffey, can be stipulated. And that would be Deaton, Yupp, Rote, Fuentes, and Anderson.

Can the parties verify, please?

COMMISSIONER FAY: This would be the opportunity to verify that those witnesses can be stipulated for FPL.

MS. MONCADA: Maria Moncada for FPL. That works for FPL.

COMMISSIONER FAY: Okay. Any objection to that?

Okay. Ms. Brownless, anything additional?

MS. BROWNLESS: FPUC has provided new numbers for its issues on October 21 and made a second revision to its numbers on October 22nd based on the Commission's approval of its stipulation and settlement in Docket No. 20190156-EI. This is in our issue list, Issue No. 3A.

At this time, are the parties willing to stipulate to FPUC's numbers? These numbers are correctly stated in the draft prehearing order you received. And its witnesses Curtis Young and Mark Cutshaw.

COMMISSIONER FAY: Okay. Thank you.

Any objections to these numbers?

MS. KEATING: Commissioner, this is Beth Keating for FPUC. No objection from FPUC.

COMMISSIONER FAY: Okay. Thank you.

MR. REHWINKEL: Commissioner, from the Public Counsel's standpoint, the language that we have provided regarding accommodating Type 2 stipulations would apply to this language -- these numbers as well.

COMMISSIONER FAY: Okay. Ms. Brownless, any others?

MS. BROWNLESS: Mr. Moyle and --

COMMISSIONER FAY: I guess, any other parties have an objection to that?

No? Great. Thank you.

MS. BROWNLESS: Finally, it's our understanding that the Office of Public Counsel would like to cross-examine DEF Witness Menendez, but appears that the OPC does not wish to cross-examine DEF Witness Lewter.

Is that correct, OPC?

MR. REHWINKEL: That is correct. And I -- I believe at least one other party would want to cross-examine Mr. Menendez, but we are not going to be crossing any other witness than Coffey and Menendez in this docket.

MS. BROWNLESS: Okay.

COMMISSIONER FAY: Okay. Can we have the party who -- who does have issue with that speak up?

MR. MOYLE: Yes, FIPUG -- FIPUG would reserve its right to ask questions of the witness.

MS. BROWNLESS: Of Witness Lewter?

MR. MOYLE: The two that F- -- that OPC identified.

MR. REHWINKEL: With respect to DEF, I was referring to Menendez as who we affirmatively will cross. And I believe FIPUG and PCS have similar intentions.

COMMISSIONER FAY: Okay.

MS. BROWNLESS: Okay.

COMMISSIONER FAY: If -- if -- FIPUG is not stipulating to Lewter, that's fine. Is that the position?

MS. BROWNLESS: I guess what I'm trying to figure out is does FIPUG and PCS Phosphate -- are they willing to excuse Witness Lewter or do you wish Witness Lewter to participate?

COMMISSIONER FAY: FIPUG --

MR. MOYLE: We -- we -- at this -- I mean, at this point, we would ask that he participate. I mean, most of the time, when we're stipulating to witnesses, we do so shortly before the -- the hearing.

I know we're at the prehearing today and we're making these accommodations, but my understanding is that the Office of Public Counsel wants to ask questions of him. If that understanding is correct, we would like to reserve our rights to ask questions of him.

That doesn't mean, if things change, you know, we can't agree to stipulate him, but at this time, we're not prepared to do so.

COMMISSIONER FAY: Sure. And I don't --

MR. BERNIER: Hey, this is --

COMMISSIONER FAY: Yeah -- yeah, go ahead.

MR. BERNIER: Thank you, Commissioner. This is Matt Bernier for Duke Energy.

Jon, I believe you were talking about two different witnesses. OPC has indicated their desire to ask questions to Chris Menendez, who would be the fuel witness on, you know, recovery factors.

The other witness, Ms. Lewter, talks to GPIF. And that's the basis of her testimony. I don't think anybody else has indicated they wanted to ask her questions.

COMMISSIONER FAY: Mr. --

MR. MOYLE: Yeah, and I'm sorry for the confusion. I -- I messed that up. So, I don't need the GPIF witness.

COMMISSIONER FAY: Yeah, Mr. Moyle, it seems like --

MS. BAKER: And this is --

COMMISSIONER FAY: -- OPC is not asking to cross Lewter. And so, just for clarification, you don't have an objection to that.

MR. MOYLE: Correct.

COMMISSIONER FAY: Okay.

MS. BROWNLESS: And does P- --

MS. BAKER: And Commissioner, this is Laura Baker for PCS. I just wanted to confirm that we will be asking -- we have questions for Menendez, but we don't have an objection to Lewter being excused.

MS. BROWNLESS: Okay. So, we're all good --

COMMISSIONER FAY: Yeah.

MS. BROWNLESS: -- with Witness Lewter being excused.

COMMISSIONER FAY: Any objection to that?

Okay. With that -- and then -- so, Mr. Brownless -- Ms. Brownless, we'll have the witnesses left on the list and they'll just -- they'll move -- at the hearing, move through the order of how they are on the list for the ones that aren't stipulated, correct?

MS. BROWNLESS: Yes. And I want to take this opportunity to be very clear about where we are putting Public Counsel's statement with regard to what "no position" means.

What we have done in our prehearing order -- and the parties have obviously (technical interruption) -- is for each issue in which the Public Counsel took no position, we have made the following statements: OPC takes no position on this issue nor does it have the burden of proof related to it.

As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the company and another party or staff as a final resolution of the issues.

No person is authorized to state that the OPC is a participant in or a party to a stipulation on this issue, either in this docket, in an order of the Commission, or in a representation to a court.

So, our draft prehearing order has that statement everywhere the Public Counsel previously took no position or no position at this time. And that statement is also included at the beginning of the stipulation where we list Type 2 stipulations that have been agreed to.

And I want to make sure that that treatment satisfies Public Counsel with regards to their position.

COMMISSIONER FAY: Could OPC just address that and just make sure it's properly stated?

MR. REHWINKEL: Yes, Commissioner, Ms. Brownless has correctly represented the conversations that we've had about how we would like this to be presented and -- and that is correct.

I believe on the language that would go with the -- in Section X, it's slightly modified to acknowledge that there are pending stipulations as in -- and it's tweaked to be in the plural, but she is -- has correctly stated our request and our position in this.

COMMISSIONER FAY: Okay. Great. And just for clarity, FIPUG does take the same position as OPC on certain issues, to be consistent with the lang- --

MR. MOYLE: That -- that's right. And we don't feel a need to restate that again, but if we take the position of OPC, then we would -- we would take that position. And I think that largely has been a common position throughout, whether it's stated or not, you know, we all work together to try to get these Type 2 stipulations, but you know, rarely has it been represented that that's an affirmative agreement to something, so --

COMMISSIONER FAY: Okay. Just wanted to make sure --

MR. MOYLE: -- we agree with it, but don't feel a need to -- to restate it.

COMMISSIONER FAY: Yeah, I appreciate that. I just want to make sure your position is consistent with what they stated.

MS. BAKER: And -- and Commissioner --

MR. MOYLE: Yeah, no, I appreciate you checking.

MS. BAKER: Sorry. Commissioner, we've also adopted the position of OPC several times, and the same thing would apply for us.

COMMISSIONER FAY: I'm sorry --

MS. BAKER: Laura Baker on behalf of --

COMMISSIONER FAY: Is that Ms. Weisenfeld?

MS. BAKER: Sorry. No, this is Laura Baker on behalf of PCS Phosphate.

COMMISSIONER FAY: Oh, and can you speak up just a little bit, Ms. Baker?

MS. BAKER: Oh, sorry. Yes. Can you hear me better now?

COMMISSIONER FAY: A little bit better.

MS. BAKER: Okay. And I was saying that we have also adopted the position of OPC on several issues and the same thing that FIPUG just said -- Jon Moyle just said would apply to us as well.

COMMISSIONER FAY: Okay. Great. So, there's specific issues that you have the "no position taken" and then others where you've adopted OPC's position, just stating that you're consistent with FIPUG on it.

MS. BAKER: Correct.

We also have a few edits on a couple of positions. Let me know when -- when is the appropriate time to -- to raise those to you.

COMMISSIONER FAY: Okay. We're going to go through the issues now.

Ms. Brownless, do you have anything else?

MS. BROWNLESS: No, sir. I just would like to speak to the basic positions.

COMMISSIONER FAY: Let's go ahead and do that and then, when we get to positions, we can have -- Ms. Baker, we can have you speak to the issues that you'd like to.

Go ahead, Ms. Brownless.

MS. BROWNLESS: With regard to the basic positions, PCS Phosphate has given changes to its basic positions, to Issues 11, 20, 22, and contested Issue A. And those will be reflected in the pin- -- in the final prehearing order.

And I apologize to Ms. Baker for having overlooked them.

COMMISSIONER FAY: Great.

MS. BAKER: Commissioner, that -- those are the edits that I was referring to and -- and Ms. Brownless already has the edits, and will incorporate them, so...

COMMISSIONER FAY: Okay. Great. And we have until close of business tomorrow to make sure that's right, so please get with her.

MS. BAKER: Sounds good. Thank you.

COMMISSIONER FAY: Great.

Ms. Brownless, (unintelligible).

MS. BROWNLESS: With regard to the issues and positions?

COMMISSIONER FAY: Yes.

MS. BROWNLESS: The OEP requires that each party take a position at the prehearing conference unless good cause can be shown why they can't do so. If a party's position in the draft prehearing order is listed as "no position at this time," that party must change it today or show good cause why it can't take a position.

Absent a showing of good cause, the prehearing order will reflect "no position" for that party on that issue. If parties have not taken a position or wish to change a position, staff suggests they be allowed to do so by close of business, Tuesday, October 27th.

A "no position" on an issue prohibits any party from cross-examining witnesses with regard to those issues or briefing on those issues. That is the order establishing procedure, Section VI.

COMMISSIONER FAY: Great. Then, we'll take up Issue A, which is the contested issue here. Ms. Brownless, you want to give us some background on that?

MS. BROWNLESS: Yes. This issue has to do with Bartow Unit 4. And the order has come out -- the Bartow order has been issued, PSC-2020-0386-FOF-EI, on (unintelligible), 2020.

With regard to that order, time for appeal has not run until November (unintelligible), time for reconsideration runs on November (unintelligible). So, there's a couple of things that we need to talk about with regard to this issue.

The first is whether the issue should be included or not; and the second is, if it is included, should it be slightly reworded. And we do have a proposal for rewording this issue from the Office of Public Counsel, intervenors.

So, with regard to --

MS. HELTON: Mr. Chairman --

MS. BROWNLESS: -- whether it should --

MS. HELTON: I'm so sorry, but the court reporter has let me know that Ms. Brownless is cutting out again.

COMMISSIONER FAY: Is --

MS. HELTON: So, we want to make sure that the -- part of the issue, as I understand it --

MR. MOYLE: Yeah, I can't hear her either. I'm not able to hear what she's saying fully either.

MS. HELTON: These new microphones -- used to be you could kind of go sway around a little bit and everyone could hear you, but these new microphones, you have to speak directly straight on into the microphone to be heard.

COMMISSIONER FAY: Great. And let's see -- Ms. Brownless --

MS. BROWNLESS: I'm --

COMMISSIONER FAY: Have we got -- and she's not cutting out; it's just we're having trouble hearing her correctly? Okay.

MS. BROWNLESS: Okay.

MR. REHWINKEL: Actually, Commissioner, from the Public Counsel, Charles. She -- on our end, she is cutting out a lot, and -- and your microphone, in fact, has starting cutting out a little bit as well.

COMMISSIONER FAY: Okay. I -- the reason I'm asking --

MR. REHWINKEL: I'm able to follow, but I just -- it seems to be getting a little worse at this stage of the process.

COMMISSIONER FAY: Gotcha. Okay. Well, I just want to make sure, Ms. Brownless, that it's not your mic and we don't need to switch you over to a chair -- essentially they can hear you, so --

MS. BROWNLESS: I mean, is this better?

COMMISSIONER FAY: Yeah.

MS. BROWNLESS: Can you hear me better now?

COMMISSIONER FAY: Yeah, can we get clarification from -- that --

MS. BROWNLESS: Okay.

COMMISSIONER FAY: Okay.

MS. BROWNLESS: All right.

COMMISSIONER FAY: Ms. Brownless, I don't know if anyone has ever complained about you or me not being loud enough. It's an interesting scenario. So, go -- go ahead. We'll give it another try.

And I appreciate the -- the parties speaking up. If you're unable to hear any of us for any reason, do not hesitate to speak up so we can get that resolved. Thank you.

MS. BROWNLESS: All right. Is that better? Can the parties hear me now?

COMMISSIONER FAY: Yeah, that's better.

MS. BROWNLESS: Okay.

COMMISSIONER FAY: Great. Thank you.

MS. BROWNLESS: With regard to this contested issue, it has to do with Duke Energy's Bartow Unit 4, and the refund of certain replacement power costs pursuant to Commission's order, PSC-2020-0368-FOF-EI, which was issued on October 15th of 2020.

So, there's two pieces to this. The first piece is, should the issue be included in this docket; and, if you determine that it should be included in this docket, exactly what the wording of the issue should be because we've received wording from the Office of Public Counsel and other intervenors that they would like substituted, should the issue stay in the docket.

For background, I just want to say that, if a motion for reconsideration is filed, it must be filed by November 2nd, which is the first day of our hearing. And if an appeal is filed, the parties have until November 16th to do so.

And with that, I think it would be appropriate to hear from the parties as to their positions on whether the issue should be included.

COMMISSIONER FAY: Okay. I -- I would agree with that.

Just to keep things in order, we'll -- why don't we have Duke speak first, then Office of Public Counsel, FIPUG, PCS Phosphate, and then staff can address it.

Duke, go -- go ahead.

MR. BERNIER: Thank you, Commissioner Fay. Matt Bernier for Duke Energy.

I -- I'll get to the issue in one second, but first I wanted to ask a clarification question to Ms. Brownless, if I could. You indicated a second ago, I think, that the -- that the order was issued on the 15th of October. And I agree that that is the date that is on the order, but I don't think it was issued to us until the 16th of October because it had to get through whatever process the clerk's office had to do.

So, I'm just trying to make sure that I have got all the dates right and I don't miss a -- a filing date somehow on that disparity. So, can you confirm for me the dates, please?

MS. BROWNLESS: Mr. Bernier, the date that I was going by was the date in which the order was recorded on the docket sheet, and that is October 15th.

I do understand what you're saying; because this was a confidential order, you were not able to be provided with that order, nor were the other parties until the next day, is my understanding.

Does that --

MR. BERNIER: That's correct.

MS. BROWNLESS: -- match with what you believe?

MR. BERNIER: That's correct for us.

COMMISSIONER FAY: Yeah, and -- and Mr. Bernier, just to be clear, just -- just, as we're taking up this issue, you're just trying to get clarification on -- on the time period for an appeal?

MR. BERNIER: That's -- that's correct, sir.

I just don't want to miss a filing date inadvertently.

COMMISSIONER FAY: Okay. And can maybe you, Ms. Helton, just clarify, make sure -- I want to make sure we get that date right for you. That's important.

MS. HELTON: I'm going to need to --

MR. MOYLE: And I want to be heard on that as well, please, if I could.

MS. HELTON: I think I'm going to need to get with Mr. Teitzman and Ms. Cibula on that. What -- what is important from everyone's perspective is the date that the court considers the order to be rendered because that is the date from which the Court will decide its 30 days for when it would have jurisdiction to hear an appeal.

And so, I'm not sure that the court would consider the day that it took to get to the parties as giving them an extra day, so --

COMMISSIONER FAY: Yeah, I --

MS. HELTON: -- I want to talk to Mr. Teitzman and Ms. Cibula, and we will, I promise, get back to everyone to confirm the that date the order was rendered.

COMMISSIONER FAY: And Ms. Helton, will we be able to get that confirmation by today or tomorrow?

MS. HELTON: To my knowledge, we should be able to do that by today or tomorrow.

COMMISSIONER FAY: Okay. Great.

MS. HELTON: Def- -- definitely by tomorrow.

COMMISSIONER FAY: Okay. Great. Thank you.

Mr. Bernier, I -- I think your -- you -- you raised that point and the question. I think that's valid. With that said, the Commission will get you the appropriate confirmation on -- on when that date is.

I actually -- I was thinking October has got 31 in it and it was released the 15th, but you'll -- not due until the 16th. It almost sounded like you had a few extra days in there, but we'll make sure we get that date confirmed for you going forward so you recognize that -- that appellate time line.

With that said, the -- the issue in front of you should still be able to be addressed and taken up. I appreciate that point of clarification.

MR. BERNIER: Sure. I very much appreciate that. Thank you, Ms. Helton, for -- for following up on that.

Regarding the actual issue, I don't think I have seen the modification that's being proposed by OPC. So, with the caveat that we may want to -- you know, to re- -- reword it a little bit after we see that, Duke does not object to having the issue, itself, in the docket.

Any -- any issues we have regarding timing and all that, we can use as a substantive issue and -- but we won't object to the actual issue.

COMMISSIONER FAY: Okay. Great.

Is -- is there a -- a party that does object to this issue?

MR. MOYLE: Yes. FI- -- FIPUG would like to be heard on it -- on this issue.

COMMISSIONER FAY: Do you have an object- -- objection, Mr. Moyle, or do you just want to be heard?

MR. MOYLE: We've talked about this quite -- quite a bit, and I have a bit of a different view on -- on this as well as the -- the timing issue. So, maybe I could just state the position on -- on the record so it's preserved.

COMMISSIONER FAY: Okay. Just, if you could, try to be clear if there is an objection or not. Thank you.

MR. MOYLE: Okay. So, we would say, yes,

there is an objection, for this reason: that the whole Bartow issue is -- is a separate stand-alone case and it has been decided. And it's governed by whatever the law is with respect to what Duke opts to do with this. And so, that would include, you know, the issue about the timing of the appeal.

I mean, you know, the Commission has already taken action with respect to rendering the order, and there's law on how that gets calculated and counted and, you know, I'm not sure that even a corrective action, you know, would -- would carry the day. I mean, it seems the safer course of action is file it on day 29 as compared to day 30 if there's doubt about that.

But -- but the whole, you know, approach as to -- as to what the fallout of the order is -- you know, there's process and procedures for how that should be done. And we just -- we just have a view and a belief that whatever that process is should -- should be followed.

It doesn't need to be immersed and interwoven into a Fuel Clause docket at this point, in our view, and you know, and Duke can take whatever action they -- they view as appropriate, given the final order that has, you know, apparently been entered on the 15th of October.

COMMISSIONER FAY: Okay. And PCS Phosphate, you also want to comment?

MS. BAKER: Yes. Yes, Commissioner. Thank you.

I -- I would agree with FIPUG that we -- we fail to see a need for the separate issue. I think we've addressed the issues in the other issues that are in the docket. And, as Mr. Moyle said, this -- the Commission has already rendered a decision. And that decision should enter into, you know, fallout issues within the body of the normal issues that are in the docket.

COMMISSIONER FAY: Okay. And anybody from staff?

MS. BROWNLESS: Yes. We have no problem keeping this issue in at this time. The reason that I mentioned the time for appeal and motions for reconsideration are because we have a rule that states, if an appeal is taken and the subject of the appeal would result in a refund on the part by the company, that if the company requests an automatic stay, they would get it.

Our real- -- rule is not discretionary in that instance; it is mandatory. And that's the reason that I bring it up; however, at this time, since we do not have an appeal, nor a motion for reconsideration, I think it's appropriate to keep the issue in so that we can track -- basically track the results of the Bartow decision.

Now, with regard to the language that OPC proposed, it's very brief and I will read it to you. The issue, as they would like to frame it -- and we have no problem with that -- is: What action should be taken in response to the Commission Order No. PSC-2020-0368-FOF-EI regarding the Bartow Unit 4 February 2017 outage?

COMMISSIONER FAY: Okay. And -- and what I -- what I would like to do, without getting into too much wordsmith-ing -- so, I appreciate what staff has done, put forward.

I do think, just to be clear, that's word-for-word OPC's recommendation of the (unintelligible), correct? Because it sounds like not every party will have OPC's recommendation.

MS. BROWNLESS: Well, actually, the parties were provided OPC's language when they reviewed -- when they got OPC's revisions to their draft prehearing order. They may not have realized.

COMMISSIONER FAY: Okay. Great. And what you read is the -- the word-for-word --

MS. BROWNLESS: Word-for-word, yes.

COMMISSIONER FAY: -- word language. Okay. Great. And --

MR. REHWINKEL: Commissioner Fay -- Commissioner Fay?

COMMISSIONER FAY: Just so I'm clear -- one second. So, the -- the rule you're speaking of is a specific rule related to a -- a refund, which makes the stay --

MS. BROWNLESS: Yes.

COMMISSIONER FAY: -- automatic --

MS. BROWNLESS: Makes the stay mandatory.

COMMISSIONER FAY: Okay. Which is a deviation for what normally -- okay.

MS. BROWNLESS: Yes.

COMMISSIONER FAY: Gotcha.

Okay. Go ahead. Mr. Rehwinkel, is that -- is that you speaking up?

MR. REHWINKEL: Yes. Yes, Commissioner. Just to be -- be clear, we submitted the language with the order number instead of the reference to the ALJ recommended order. As -- if the or- -- if the issue is going to stay in, we at least wanted the reference to be to the order and not to the judge's recommended order.

COMMISSIONER FAY: Okay.

MR. REHWINKEL: And we provided a position as well, if that issue stays in.

I can say we are fairly agnostic to that issue staying in. We feel like we can address the refund issue -- I think it's in Issue 11; however, that's really -- I -- I'm kind of indifferent about it. I -- I certainly -- I understand and am largely in agreement with my co-counsel on the intervenor's side as far as whether it's truly needed.

But we really wanted to make sure the wording was -- was correct, if anything.

COMMISSIONER FAY: Okay. Great. Well -- so, hearing from all the parties on this, I'm inclined to leave to it in. I think Ms. Brownless makes a good point. We can't really predict the future on this. So, at this point in time, I -- I'd prefer to leave it in.

I don't have any issue with the recommendation -- the recommended language from the Office of Public Counsel that speaks specifically to the order number instead of the DOAH judge's reference. And so, if we could just, as we leave it in, make that correction, Ms. Brownless, to make sure, when it goes out tomorrow, that that correction is made.

With that, do we have any other issues, Ms. Brownless?

MS. BROWNLESS: Yes, sir.

COMMISSIONER FAY: Go ahead.

MS. BROWNLESS: Because you ruled that the issue stays in, DEF will have to provide a position on that issue by close of business tomorrow.

COMMISSIONER FAY: Okay. And Duke, can you confirm you -- you've heard that instruction?

MR. BERNIER: I did. We will do so. Thank you very much.

COMMISSIONER FAY: Okay. Great. Thank you, Ms. Brownless.

Anything else?

MS. BROWNLESS: No, sir.

COMMISSIONER FAY: With that, we'll move on to the exhibit list.

MS. BROWNLESS: Staff has prepared a comprehensive exhibit list which includes all prefiled exhibits and also includes exhibits staff wishes to introduce into the record. Staff will work with the parties to determine if there are any objections to the comprehensive exhibit list or any of staff's exhibits being entered in -- being entered into the record.

COMMISSIONER FAY: Okay. Section X, proposed stipulations.

MS. BROWNLESS: The proposed stipulations for Gulf and TECO are listed in Section VII of the draft prehearing -- Section X, I'm sorry -- of the draft prehearing order. And, as we discussed before, they're subject to OPC's statement defining a Type 2 stipulation.

Staff will continue to work with all parties to reach stipulations on the outstanding issues. A list of stipulations entered into after the prehearing order is issued will be provided to all parties and the Commissioners prior to the hearing.

COMMISSIONER FAY: Thank you.

Section XI, pending motions, and Section XII, confidentiality orders.

MS. BROWNLESS: There are no pending mission motions at this time. There are no outstanding confidentiality motions at this time. Orders have been written and are in the process of being issued by (technical interruption).

COMMISSIONER FAY: Thank you for your work on this.

Section XIII, the post-hearing procedures.

MS. BROWNLESS: Parties agree to waive briefs. The Commission may make a bench decision for this portion of the docket. If briefs are necessary, staff recommends that briefs be no longer than 40 pages.

COMMISSIONER FAY: Section XIV, rulings.

MS. BROWNLESS: Staff recommends that the prehearing officer make a ruling that opening statements, if any, should not exceed five minutes per party unless any party chooses to waive its opening statement.

COMMISSIONER FAY: I would confirm that recommendation.

Anything else?

MS. BROWNLESS: Lastly, all cross-examination exhibits that a party intends to use at the hearing must be provided to the Commission clerk by close of business on October 27th, 2020, in order to be processed and made available digital- -- digitally.

Attachment A to the draft prehearing order explains the process for the parties to follow when providing cross-examination exhibits to the clerk. The exhibits that are prefiled and designated as cross-examination or impeachment exhibits shall not be viewed by opposing witnesses or opposing counsel or otherwise have their contents or identity communicated to such witness or counsel.

COMMISSIONER FAY: Thank you.

And any -- any parties have any objections to those two rulings?

MR. REHWINKEL: No -- Commissioner Fay, I have one.

COMMISSIONER FAY: Yes, Mr. Rehwinkel. Go ahead.

MR. REHWINKEL: Really more of a question to -- to the Commission and staff. For Witness Menendez, I think our only exhibit, cross-examination exhibit, is going to be the Bartow order. And I think right now it has not been redacted, but I could be wrong.

MS. BROWNLESS: No, sir.

MR. REHWINKEL: And my -- my question is: Is there a preference as to whether we actually provide that as a -- as an exhibit in the "C" side of the cross-examination file or, because the Commission takes note -- or official recognition of its own orders, would you prefer us not to do that?

I'm happy to do it either way. It may be easier if people just have the document and can access it and reference it, unless there are some other issues with respect to the dissemination of confidential orders to the broader 01 community here.

COMMISSIONER FAY: Yeah, it's -- it's a good question, Mr. Rehwinkel. I -- as the Commission typically operates, those orders can be included, but because of confidentiality, I want to make sure with our general counsel's office that we get that correct because it's -- it's important to get it done by -- make sure that that is available by October 27th, so the -- have that process, but as far as --

MR. REHWINKEL: I can say this -- if it would facilitate -- I can prepare the exhibit and I -- I can just wait -- you don't necessarily have to answer it on the fly here today. I put that issue out there. We'll be prepared to file it by the end of the day tomorrow or change course as we are advised by the general counsel's office, if that would help.

COMMISSIONER FAY: No, that -- that's fine. And I do think it is an issue -- I mean -- an issue that needs to get resolved because we want to make sure it's done in a timely manner.

So, let me just check with our general counsel's office as to process, ensuring that confidentiality is done properly before just (technical interruption).

MS. HELTON: Mr. Chairman, normally, our orders -- we have gone on record saying that we will officially recognize all of our orders, but this order, because we are all dealing with this hearing remotely and because a good portion of the order will be redacted and is confidential -- I think, in my mind, the easiest way to go about it would be to have it included as an exhibit and -- and made part of the confidential filing -- I can't remember what we're exactly calling that, but part of the confidential record that everyone will be able to access remotely.

I think there should probably be a redacted version and a highlighted version.

COMMISSIONER FAY: Yeah. And, Ms. Brownless, if -- if you could just add to this because I want to make sure that, from my perspective, we don't need to initiate any (technical interruption).

MS. BROWNLESS: I think Ms. Helton is correct about having the Office of Public Counsel file it as an exhibit tomorrow and label is as "C" so that the clerk's office knows it goes in "C", in the confidential portion.

With regard to having a redacted version, the way this has worked in the past is that it is Duke's order. The information that is sought to be confidential belongs to Duke and Duke's third-party contractor. So, Duke has 21 days from the date that the order was entered to file a request for confidentiality and provide a redacted version.

That being the case, I doubt we will have a redacted version by the date of the hearing.

MS. HELTON: Can we ask Mr. Bernier, Mr. Chairman, if they can expedite that redaction? Because I think it would help this hearing tremendously to know exactly what it confidential and what is not confidential.

COMMISSIONER FAY: Yeah, that's -- that's a fair question. I think, for purposes of ensuring that -- you know, erring on the side that we're -- we're appreciating the proprietary nature and confidentiality of some of that information and that the portions of it do meet the exemptions that are allowed out there.

Mr. Bernier, what -- what sort of turnaround would you be able to provide that -- that redacted order to ensure that the information that's distributed is not unintentionally putting proprietary -- and I know that includes you -- both you and third-party information. So, I want to make sure we get this right.

MR. BERNIER: I will work to get it turned around as soon as I can. I know we have already gone through the ALJ's order, which is appended to the Commission's order, and highlighted that and filed for confidentiality previously.

I wasn't thinking really that, we needed to do that again -- but if we do, we will go through it. And then I'll take another look through the Commission's actual order as well and make sure that there's nothing there.

As far as timing goes, tough turnaround by the end of the day tomorrow. Could I have an additional day on top of that to get that done?

COMMISSIONER FAY: Yeah. And, Mr. Bernier, just to be clear, I think what Office of Public Counsel has stated with -- with some clarity is that they would be referencing the order specifically out of the Commission and not the DOAH judge's order. And so, I think the significance would be that we would need to make sure the

Commission order has been redacted.

MR. BERNIER: Yes, sir, will do.

COMMISSIONER FAY: Great. Thank you.

MR. REHWINKEL: Commissioner, if I could offer this, we're happy -- I'm not sure exactly how the -- the -- the partitioning of that file goes, but assumedly, only staff, Duke, OPC, FIPUG, and PCS should be able to access that order if we upload the unredacted version.

I don't know if others could get to it, but to avoid any possibility that there's a problem there, I would be happy to -- if it's okay with you -- because I don't -- I don't think we're going to have a significant -- well, that's the only exhibit we're going to have there. We might have two others for FPL. We're going to have a very small number of exhibits to upload, and there have been no glitches that I'm aware of in that.

If it could be accommodated that we can wait for the Duke order -- I'm happy to file the FPL stuff tomorrow, as planned. If we can wait until we get a redacted order, I would be happy to file the redacted order and not have to put confidentiality at issue at all, if --

COMMISSIONER FAY: Okay. Yeah, and I think that would be the -- be the goal here for the other two that you're speaking of. You're stating you'll file those by close of business tomorrow for the cross exhibits?

MR. REHWINKEL: Yes.

COMMISSIONER FAY: Okay. Great. And so, then specifically to the Duke redacted, you're -- to your point, it's a resolution, if they're able to provide that information by the close of business tomorrow, to have it filed?

MR. REHWINKEL: I'll -- whenever they redact it, I'll file it as an exhibit if we can get some leeway to file it after your -- your deadline. I don't think it's a logistical problem --

COMMISSIONER FAY: Okay.

MR. REHWINKEL: -- with this one document if -- if we have to wait a day or two extra.

COMMISSIONER FAY: No, I -- I understand. I just --

MR. REHWINKEL: But I -- I don't want to presume that.

COMMISSIONER FAY: Yeah, Mr. Rehwinkel, I want to make sure we stick on that time line.

So, Ms. Brownless, what would be -- as far as presenting that redacted document to the

Commission, what would be the alternative to that, to make sure (technical interruption)?

MS. BROWNLESS: What we would like, in order to get the exhibits together for the hearing, we would like OPC to file the -- our order confidentially tomorrow, and then --

MR. REHWINKEL: Okay. Will do.

MS. BROWNLESS: That works best procedurally for us processing the materials.

COMMISSIONER FAY: Okay. Which would only be accessible to the current parties.

MS. BROWNLESS: Exactly.

COMMISSIONER FAY: Right. Okay.

MR. REHWINKEL: Okay.

COMMISSIONER FAY: That -- that's fine with me, Mr. Rehwinkel. Is that okay with you?

MR. REHWINKEL: Yes, sir. And I apologize for the diversion on this, but I just wanted to be clear on it. And I'm happy.

COMMISSIONER FAY: No, I appreciate that. I have all these -- these clause dockets and -- and there would be accusations that it went way too smoothly. So, I appreciate you throwing in a little -- a little wrinkle there at the end, but I think we have it resolved.

Mr. Bernier, is that sufficient for you?
MR. BERNIER: Yes, sir, we will get it done.
COMMISSIONER FAY: Great. Thank you.
MS. BAKER: And Commissioner Fay, this is Laura Baker for PCS. I just wanted to echo and say, you know, if we use the exhibit, we could use the redacted version. So, we wouldn't need the confidential version if -- you know, if you can take it out and have it not be an issue, then we wouldn't have any objections to that. We -- we would be fine with the redacted version to work from.
COMMISSIONER FAY: Okay. Great. Thank you.
Any other matters from the parties?
MR. MOYLE: I -- I have one -- just kind of a process question, along the lines of what has been discussed, but it seems to me that -- that we're positioned now to have an issue that relates to the Bartow docket and the refund being decided in the Fuel Clause docket.
So, for the purposes of making sure that the record in the Bartow docket is clear, I was wondering whether staff has given thought as to what, you know, will be dual -- dual filings in the -- in the Bartow docket to reflect, you know,

what's happening with respect to this issue because the issue is now going to be, you know, decided in the fuel docket, it sounds to me.

So, I just want to -- was curious about how that record will be preserved. And it seems, just upon initial thought, that maybe also filing actions that are taken with respect to this refund issue probably makes sense to put them in the Bartow docket as -- as well.

COMMISSIONER FAY: Yeah, Mr. Moyle, I'll get clarification from -- from our staff on that to make sure we're -- we're in the right posture. That seems like a separate operation (technical interruption) issues if you don't know exactly what the future will hold on that, but let me -- Ms. Brownless, do you have any comments on that before we close --

MS. BROWNLESS: Yes. Mr. Moyle, this -- this fuel docket is not deciding anything with regard to the Bartow case. The Bartow docket is one that was conducted by Judge Stevenson, is complete, and there is a final order for that decision. Okay. So, that's marching along in its own procedural posture.

The only thing we are doing here in the Fuel

Clause is talking about the timing of the refund. Okay. Will the refund be done this year or the -- will the refund be done next year.

If there is an appeal filed and the appeal is pending, then, obviously, we have to wait and decide whether a refund will be made based upon the outcome of the appeal.

So, we're not combining the docket. All we're talking about here is where the 16-million bucks gets refunded or not refunded. It has nothing to do with the underlying merits (technical interruption).

COMMISSIONER FAY: Mr. Moyle, your -- your point is taken. For the record, I appreciate it. I do think this can be moved forward without concerns for that. I -- I see where you're coming from, but I think, from a clause perspective and (unintelligible) perspective, we're --

MR. MOYLE: No, I appreciate it. I mean, we -- we take the view that the 16 million is material. We would rather have it sooner than later and -- so, anyway, but I think -- I think we understand --

COMMISSIONER FAY: Okay.

MR. MOYLE: -- that so -- so, thank you for letting me make that point.

COMMISSIONER FAY: Sure. No problem.

Any other matters, I guess, Ms. Brownless, that we need to address?

MS. BROWNLESS: No, sir. Thank you.

COMMISSIONER FAY: Okay. With that, we will conclude the 01 docket, which also concludes this prehearing conference.

Thank you. We're adjourned.

(Whereupon, the proceedings concluded at 2:52 p.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, ANDREA KOMARIDIS WRAY, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 6th day of November, 2020.

ANDREA KOMARIDIS WRAY
NOTARY PUBLIC
COMMISSION #GG365545
EXPIRES February 9, 2021

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor __________________________________/	DOCKET NO. 20200001-EI FILED: November 9, 2020

CONSUMER PARTIES' JOINT RESPONSE TO MOTION FOR STAY

The Citizens of the State of Florida, through the Office of Public Counsel, ("OPC"), The Florida Industrial Power Users Group ("FIPUG") and White Springs Agricultural Chemicals d/b/a PCS Phosphate ("PCS"), collectively the Consumer Parties ("Consumers"), submit this response in opposition for the Motion to Stay ("Motion") filed by Duke Energy Florida, LLC ("DEF" or "Duke" or "Company"). The Motion to withhold, for up to 6 years, $16.1 million of improvidently collected customer funds for damages caused by the imprudent operation of a Duke power plant should not be granted. Rule 25-22.061(1)(a), Florida Administrative Code ("Rule"), does not apply to the self-correcting true-up mechanism that embodies the fuel clause, and the Florida Supreme Court has effectively deemed it surplusage. Additionally, the Motion itself demonstrates that the fuel clause is self-correcting, and no stay is warranted. In support, the Consumers state as follows:

2017 outage replacement costs and the 2017 "over/under account" stipulation demonstrates the inapplicability of the Rule.

For purposes of this response, DEF's description of the effect of Commission Order No. PSC-2020-0368-FOF-EI ("Bartow Order") adopting the Division of Administrative Hearings ("DOAH") Judge's Recommended Order is accurate. That order found that the customers had incurred damages in the amount of $16.1 million in replacement power costs, which DEF has recovered from those customers in its adjusted and updated fuel factor charges collected in 2019 and 2020. Bartow Order at 18-21; 55-56. These damages are comprised of two elements. $11.1 million is attributable to the two-month period in 2017 when the entire Bartow unit was off-line. Another $5 million was attributable to the 40 MW de-rating of the unit that began in May 2017 and continued until mid- 2019 and was occasioned by the installation of a pressure plate that limited the output of the unit pending a more permanent repair to Bartow's damaged steam generator. Bartow Order at 18-21; 55-56.

In the Spring of 2017, after DEF had experienced the two-month outage at its Bartow Unit 4 (Steam Turbine) and installed the power limiting pressure plate, the Commission approved a stipulation between DEF and customer representatives in which DEF agreed it would not seek to recover the then estimated $11 million in replacement power costs associated with the outage. Instead, DEF agreed to record the estimated replacement fuel costs in an "over/under account" for future recovery in the fuel clause. This recovery occurred throughout the year 2019. TR 356.[1] DEF witness Menendez conceded that the "over/under account" preserved the Company's opportunity to recover the costs in a future period. TR 356-357. DEF's fuel factor calculations accordingly were lower in 2018 than its actual/estimated costs by $10.9 million because the Company accounted for the unrecovered costs in the "over/under account" and not through its fuel clause recovery mechanism.

DEF witness Menendez testified in the fuel clause hearing this year that the Company was able to submit the 2017 outage replacement costs for clause recovery one year later because of the availability of the "over/under account." He described the true-up function of the account in this manner:

> The over/under account that is being referred to is otherwise known as the true-up balance, or the true-up variance.
>
> ***
>
> It is a variance between the revenues collected an [sic] the expense occurred [sic] in the clause account.

TR 355. This mechanism conclusively demonstrates that the fuel clause is self-correcting and adequately provides a mechanism for restoring the *status quo ante* on the chance that the Court orders that DEF should recover the disputed replacement power costs addressed in the Bartow Order. Accordingly, there is no need to interject the surplus stay mechanism into the fuel clause.

[1] Transcript references are to the transcript of the November 2, 2020 hearing in Docket No. 20200001-EI.

De-rate replacement power costs have not been deemed reasonable or prudent and should not be stayed in any event.

As noted, the outage costs were not the only costs at issue in the Bartow order. In 2018, Duke began charging customers for replacement power costs attributable to the de-rating of the Bartow Unit 4 (steam turbine) that was determined by the Commission to have been caused by the 40 MW de-rating of the Steam Turbine. The de-rating of the Bartow unit occurred from May 2017 to September 2019. Order No. PSC-2020-0368A-EI ("Bartow Order") at 56; TR 358-361 (Bernier stipulation). There was no evidence that the replacement power costs required because of the de-rating were ever recorded in the "over/under account" since these costs were apparently never withheld from recovery or separately identified by DEF. Regardless, DEF collected the money with no Commission review until the conduct of the hearing that was referred to DOAH in 2019. These funds were ruled to be imprudently collected. Now DEF is seeking to retain for up to 2-3 more years funds that were never expressly approved or even considered by the Commission in a reasonableness or prudence determination until the vote on September 1, 2020 denying recovery. By itself, this portion of the overcollections should not be subject to a stay given the provenance of no Commission action in approving them as replacement power costs.

The Rule is not applicable to the self-correcting true-up mechanism of the fuel clause and is not mandatory and is in fact mere surplusage.

DEF asks the Commission to treat the provisions of Rule 25-22.061(10)(a), Florida Administrative Code, as mandatory and cites an inapposite water and sewer rate case as an example where a refund of moneys was ordered and stayed in accordance with the Rule.[2] This rule has never been applied to a case where the self-correcting provisions of the fuel clause were available. There is a good reason for this. The Rule is not necessary or designed to be used in conjunction with the fuel clause. As noted above, implementing the requirements of the Bartow Order simply requires an update to DEF's fuel factor calculations, which is an unremarkable, common occurrence throughout the fuel clause proceedings. TR 379. DEF provides a return of any court-mandated refund of moneys by the crediting of the fuel factor mechanism and the use of the "over/under account" in the same fashion that it already has demonstrated adequately protects its

[2] *In re Aloha Utilities, Inc*, 2005 WL 405335 (Fla. P.S.C. Feb. 7, 2005).

interests. Moreover, the Florida Supreme Court has stated that the stay contemplated by the Rule does not function to protect the rights of a utility to recover its costs for which it has been improperly denied recovery. A regulated telecommunications company, upon appealing a Commission order, did not request a stay when it filed the appeal. Upon remand, after losing the appeal of its order denying affiliate transactions cost recovery and because no stay was sought, the Commission erroneously denied the company full recovery of the costs beginning with the effective date of the original Commission order. The Court stated:

> Both the Florida Statutes and the Florida Administrative Code have provisions by which GTE could have obtained a stay. However, neither of those mechanisms is mandatory. We view utility ratemaking as a matter of fairness. Equity requires that both ratepayers and utilities be treated in a similar manner.
>
> ***
>
> It would clearly be inequitable for either utilities or ratepayers to benefit, thereby receiving a windfall, from an erroneous PSC order. The rule providing for stays does not indicate that a stay is a prerequisite to the recovery of an overcharge or the imposition of a surcharge. The rule says nothing about a waiver, and the failure to request a stay is not, under these circumstances, dispositive.

GTE v Clark (Fla 1996), 668 So. 2d 971, 972-973. The essence of the *GTE* decision is that, even in a rate case scenario where there is no self-correcting true-up mechanism like there is here, the Stay Rule is an anachronism that serves no purpose to protect the rights of a utility to recover its lawful costs when prevailing on appeal. In any event, there is no evidence that the Commission intended the Rule to apply to the specialized true-up mechanism subsumed in the fuel clause.

DEF's request for relief from the bond or corporate undertaking provisions demonstrate the Rule does not apply to the fuel clause.

Despite invoking the purported mandatory nature of the Rule in granting the stay, the Company asks the Commission to ignore what can only be read as an equally mandatory imposition of conditions of bond or corporate undertaking (or the functional equivalent thereof) that requires that the "stay ***shall*** be conditioned…." (Emphasis added.) Amazingly, DEF urges the Commission to ignore this mandatory provision precisely because of the self-correcting nature of the fuel clause thusly:

> Given the circumstances of this case and the on-going nature of the fuel docket, DEF should not be required to post a bond, corporate undertaking, or any other conditions to secure the revenues collected by DEF that may ultimately be subject to refund if the order under appeal is upheld; that is, because such a refund would take the form of a reduction in DEF's fuel collections for the refund period, no bond, undertaking or other assurances are necessary or appropriate.

This internally inconsistent effort to evade the otherwise non-discretionary nature of the assurance provision bolsters the Consumers' position that the Rule was not intended to apply to collections in the fuel clause.[3]

The Commission has no basis to grant a stay pursuant to the "discretionary" provisions of the Rule.

The Company purports to seek to make a showing that it is entitled to discretionary relief by referencing its case that was rejected by the Commission as a demonstration that it is likely to prevail on the merits. This colorable claim based on a previously advanced and twice rejected argument is insufficient on its face and does not amount to a "demonstration." At a minimum, DEF must advance an argument that shows that good reasons for anticipating that result (success on the merits) are demonstrated. It is not enough that a merely colorable claim is advanced. *City of Jacksonville v. Naegele Outdoor Advertising Co*., 634 So. 2d 750, (Fla 1st DCA 1994). (Court applied the standard to the threshold of demonstrating the likelihood of prevailing on the merits in an injunctive relief context.)

An even greater failure is shown in the complete absence of a showing by DEF that it will sustain irreparable harm if the stay is not granted. This argument is internally inconsistent with, and self-defeated by, the request to not require DEF to implement the mandatory posting of a bond or corporate undertaking or other conditions – i.e. because of the availability of the self-correcting

[3] In 1992-1993, the Commission delayed the implementation of the brand-new Capacity Cost Recovery Clause ("CCRC") as to Gulf Power in a dispute over whether to offset revenues from sales to another utility with certain costs that were being recovered in base rates. Order No. PSC-1992-1361-FOF-EI at 2. The Commission cited the Rule but, as to Gulf Power Co., ended up delaying implementation of the inaugural CCRC. This action did not involve a "refund of moneys," as is alleged to be the situation here. In the *Gulf* case, the Commission would have otherwise implemented a rate reduction in the inaugural CCRC, and thus would not have reduced an *existing* rate charged to customers. Order No. PSC-1992-1001-FOF-EI at 18. That dispute was resolved on reconsideration and the appeal was dismissed and any notion of a stay – if ever implemented – was moot. Likewise, there was no action taken to lift a stay. Order No. PSC-1993-0047-FOF-EI. It is not even clear to what extent a stay was ordered under the Rule or if there was any consideration at that time that the CCRC operates as a true-up mechanism like the fuel clause. Regardless, the 1992-1993 CCRC case was not a fuel clause case and it predated the Supreme Court's holding in *GTE* that effectively neutered the import of the Rule in any event.

true-up mechanism in the fuel clause. On its face, the irreparable harm standard cannot be met or even countenanced. This "throw away" request for alternate discretionary relief merely serves to illustrate that the Rule is not intended or designed to provide relief from a Commission order in the context of the self-contained fuel clause mechanism.

Conclusion.

At the end of the day, the Consumers submit that the Commission should decline to order a stay of the requirement to credit $16.1 million to DEF's fuel factor for 2021.[4] Collections of the replacement power costs began in 2017 and largely ended in 2019. Witness Menendez acknowledged that if the credit is not made in the 2021 cycle and a stay is granted, customers would likely not begin to see their money returned until 2023 at the earliest and their money would not be fully returned until the end of 2023 in the likely event DEF fails to convince the Supreme Court that its version of the conclusions of law can be supported by the 102 contrary findings of facts to which the Company agreed. To some extent, if a stay is granted, these customer dollars will not be restored until 5-6 years after the customers originally began paying for the imprudently incurred costs. TR. 373 - 374. Of particular note is that 31% of the funds (related to de-rate costs) that the DEF asks the Commission to let it hold for another 2-3 years, were never even approved by the Commission as reasonable or prudent for recovery as replacement power costs. This fact further mitigates against application of the mistakenly characterized non-discretionary nature of the Rule.

In summary, the Consumers urge the Commission to deny the stay. Customers have over-paid these replacement power costs for years now and are entitled to a return of the funds. The Rule is incompatible with the operation of the rate setting mechanism of the fuel clause and should not be applied to allow DEF to keep its customers' money through the end of 2023. The Consumers

[4] DEF has not sought to invoke the Rule on the second prong of the test ("…decrease in rates charged to customers…") because the relief ordered by the Commission in the Bartow Order does not involve a decrease in the rates charged to customers. DEF already had proposed a decrease in the current rate. TR 345. DEF witness Menendez speculated without factual predicate that crediting the $16.1 million in replacement power costs years in the future would reduce customer rates, and this was not grounded in fact. TR 394 - 395. He offered no evidence of what rates would be in two years or what the starting point would be. Logic supports that there would be a reduction in *collections*, but that is what happens in the true-up process. TR 379. How customer rates currently being paid will be affected, if at all, is unknowable.

submit that the 2017 stipulation that resulted in the forbearance of outage replacement power costs in 2018, can be utilized in concert with the "over/under account" to protect DEF in the unlikely event that it prevails on appeal.

The Consumers are willing to stipulate, if necessary (which we think it is not given the self-correcting true-up nature of the fuel clause) that DEF would be able to credit the clause with the $16.1 million (plus interest) for 2021 fuel factor purposes and debit the "over/under account" so that if DEF prevails on appeal, the process can be reversed and the "over/under account" would be credited and the fuel factor would be debited by the amount ordered collected from customers. This is how the fuel clause operates ordinarily and independently of the stay provisions of the Rule. The GTE decision confirms that this type of equity and fairness works regardless of the invocation of the Rule. DEF's Motion should be denied.

Respectfully submitted by Consumers,

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing **CONSUMER PARTIES' JOINT RESPONSE TO MOTION FOR STAY** has been furnished by electronic mail on this 9th day of November, 2020, to the following:

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 20200001-EI ORDER NO. PSC-2020-0431-CFO-EI ISSUED: November 10, 2020

ORDER GRANTING REQUEST FOR CONFIDENTIAL CLASSIFICATION (DOCUMENT NO. 11612-2020, X-REF. 11211-2020)

On October 29, 2020, pursuant to Section 366.093, Florida Statutes (F.S.), and Rule 25-22.006, Florida Administrative Code (F.A.C.), Duke Energy Florida, LLC (DEF) filed a Request for Confidential Classification (Request) of the Florida Public Service Commission's Order No. PSC-2020-0368-FOF-EI, issued October 15, 2020 (Document No. 11612-2020, x-ref. 11211-2020).

Request for Confidential Classification

DEF contends that the information contained in Order No. PSC-2020-0368-FOF-EI, more specifically described in Exhibit C to its Request, constitutes proprietary confidential business information entitled to protection under Section 366.093, F.S., and Rule 25-22.006, F.A.C. DEF asserts that this information is intended to be and is treated by DEF as private and has not been publicly disclosed.

The information contained in Order No. PSC-2020-0368-FOF-EI consists of operational, design, and cost information associated with the Mitsubishi steam turbine connected to DEF's Bartow Unit 4 power plant which is proprietary to Mitsubishi. Order No. PSC-2020-0368-FOF-EI also includes the Administrative Law Judge's Recommended Order and Duke Energy Florida, LLC's, the Intervenors', and Commission staff's Proposed Recommended Orders which have previously been granted confidential status.[1] Disclosure of Order No. PSC-2020-0368-FOF-EI would reveal this proprietary third-party owned information resulting in competitive harm to Mitsubishi and potentially impairing DEF's ability to contract for goods and services on favorable terms in the future as vendors would refuse to do business with DEF if DEF could not protect their information. DEF argues that this information is protected by Subsections 366.093(3)(d) and (e), F.S.

Ruling

Subsection 366.093(1), F.S., provides that records the Florida Public Service Commission (Commission) has found to contain proprietary business information shall be kept confidential and shall be exempt from Chapter 119, F.S. Subsection 366.093(3), F.S.,

[1] Order No. PSC-2020-0377-CFO-EI, issued October 16, 2020, in Docket No. 20200001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor;* Order No. PSC-2020-0376-CFO-EI, issued October 16, 2020, in Docket No. 20200001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

defines proprietary confidential business information as information that is intended to be and is treated by the company as private, in that disclosure of the information would cause harm to the company's ratepayers or business operations, and has not been voluntarily disclosed to the public. Subsection 366.093(3), F.S., provides that proprietary confidential business information includes, but is not limited to:

> (d) Information concerning bids or other contractual data, the disclosure of which would impair the efforts of the public utility or its affiliates to contract for goods or services on favorable terms.
>
> (e) Information relating to competitive interests, the disclosure of which would impair the competitive business of the provider of the information.

Upon review, it appears the information and data provided in this request satisfies the criteria set forth in Subsection 366.093(3), F.S., for classification as proprietary confidential business information. The operational, design, and cost information for the DEF's Bartow Unit 4 power plant discussed in Order No. PSC-2020-0368-FOF-EI appear to be "information concerning bids or other contractual data, the disclosure of which would impair the efforts of the public utility or its affiliates to contract for goods or services on favorable terms" and "information relating to competitive interests, the disclosure of which would impair the competitive business of the provider of the information." Thus the information identified in Document No. 11612-2020, x-ref. 11211-2020, shall be granted confidential classification.

Pursuant to Subsection 366.093(4), F.S., the information for which confidential classification is granted herein shall remain protected from disclosure for a period of up to 18 months from the date of issuance of this Order. At the conclusion of the 18-month period, the confidential information will no longer be exempt from Section 119.07(1), F.S., unless DEF or another affected person shows, and the Commission finds, that the records continue to contain proprietary confidential business information.

Based on the foregoing, it is hereby

ORDERED by Commissioner Andrew Giles Fay, as Prehearing Officer, that Duke Energy Florida, LLC's Request for Confidential Classification of Document No. 11612-2020, x-ref. 11211-2020, is granted, as set forth herein. It is further

ORDERED that the information in Document No. 11612-2020, x-ref. 11211-2020, for which confidential classification has been granted, shall remain protected from disclosure for a period of up to 18 months from the date of issuance of this Order. It is further

ORDERED that this Order shall be the only notification by the Commission to the parties of the date of declassification of the materials discussed herein.

By ORDER of Commissioner Andrew Giles Fay, as Prehearing Officer, this 10th day of November, 2020.

ANDREW GILES FAY
Commissioner and Prehearing Officer
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

Any party adversely affected by this order, which is preliminary, procedural or intermediate in nature, may request: (1) reconsideration within 10 days pursuant to Rule 25-22.0376, Florida Administrative Code; or (2) judicial review by the Florida Supreme Court, in the case of an electric, gas or telephone utility, or the First District Court of Appeal, in the case of a water or wastewater utility. A motion for reconsideration shall be filed with the Office of Commission Clerk, in the form prescribed by Rule 25-22.0376, Florida Administrative Code. Judicial review of a preliminary, procedural or intermediate ruling or order is available if review of the final action will not provide an adequate remedy. Such review may be requested from the appropriate court, as described above, pursuant to Rule 9.100, Florida Rules of Appellate Procedure.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

Fuel and purchased power cost recovery clause with generating performance incentive factor	))))	Docket No. 20200001-EI Filed: November 10, 2020

POST-HEARING BRIEF AND STATEMENT OF WHITE SPRINGS AGRICULTURAL CHEMICALS, INC. D/B/A PCS PHOSPHATE – WHITE SPRINGS

Pursuant to Rule 28-106.215, F.A.C., and the Prehearing Order, Order No. PSC-2020-0415-PHO-EI, issued in this proceeding on October 30, 2020, White Springs Agricultural Chemicals Inc., d/b/a PCS Phosphate – White Springs ("PCS") hereby submits its Post-Hearing Brief and Statement of Issues.

INTRODUCTION

At its agenda conference held on September 1, 2020, the Commission voted to adopt, without modifications, the findings and recommendations ("Recommended Order") of the Department of Administrative Hearings ("DOAH") which concluded that Duke Energy Florida ("Duke" or "DEF") should not be permitted to recover in consumer rates the replacement power costs associated with the 2017 DEF Bartow Unit 4 outage and subsequent de-rating. The disputed costs had previously been included in fuel clause charges pending that Commission determination. In its recommendation memorandum, Public Service Commission Staff stated that DEF should credit the fuel clause cost recovery for $11.1 million in replacement power costs associated with its April 2017 Bartow Unit 4 outage and $5,016,782 for replacement fuel costs associated with the de-rating of the unit from May 2017 until December of 2019 in its fuel cost calculations, for a total credit of $16,116,782.[1] Based on the Commission's final Order No. PSC-2020-0368-FOF-EI,

[1] Docket No. 20200001, Fuel and purchased power cost recovery clause with generating performance incentive factor, *Memorandum from Public Service Commission Staff* at 23 (Aug. 6, 2020).

issued October 15, 2020, DEF should credit those disallowed costs in the determination of its fuel clause factor to be collected in 2021.

I. <u>Post Hearing Statement of Issues and Positions</u>

Consistent with the discussion at the November 3, 2020 hearing, PCS limits its post-hearing statements of position to issues 1A, 11, 18, 20, and 22 as DEF issues and fallout issues relating to the impact on the fuel clause of Order No. 2020-0368-FOF-EI, issued October 15, 2020.

<u>ISSUE 1A:</u> What action should be taken in response to Commission Order No. PSC-2020-0368-FOF-EI regarding the Bartow Unit 4 February 2017 outage?

PCS Phosphate: **Based on Order No. PSC-2020-0368-FOF-EI, issued October 15, 2020, the Commission should direct DEF to reduce its proposed cost recovery amounts for January 2021 through December 2021 by $16.1 million, plus interest, to credit the fuel clause recovery for costs relating to the replacement power and de-rating of Bartow Unit 4.**

<u>ISSUE 11:</u> What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2021 through December 2021?

PCS Phosphate: **Pursuant to Order No. PSC-2020-0368-FOF-EI, DEF's cost recovery amounts for January 2021 through December 2021 should be reduced by $16.1 million, plus interest, to credit the fuel clause recovery for costs relating to the replacement power and de-rating of Bartow Unit 4.**

<u>ISSUE 18:</u> What are the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2021 through December 2021?

PCS Phosphate: **Agree with OPC.**

<u>ISSUE 20:</u> What are the appropriate levelized fuel cost recovery factors for the period January 2021 through December 2021?

PCS Phosphate: **Pursuant to Order No. PCS-2020-0368-FOF-EI, DEF's cost recovery amounts for January 2021 through December 2021 should be reduced by $16.1 million, plus interest, to credit through the fuel factor costs relating to the replacement power and de-rating of Bartow Unit 4. **

ISSUE 22: **What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?**

PCS Phosphate: **Pursuant to Order No. PSC-2020-0368-FOF-EI, DEF's cost recovery amounts for January 2021 through December 2021 should be reduced by $16.1 million to credit through the fuel factor costs relating to the replacement power and de-rating of Bartow Unit 4. To the extent that this reduction in allowed cost recovery reduces the fuel cost recovery factors for DEF, those factors should be adjusted.**

II. Argument

All parties agree that DEF has recovered the disputed Bartow replacement power fuel costs in its 2019 and 2020 fuel factors. There also is no dispute that the actual true-up for 2019 includes replacement fuel costs associated with the Bartow de-rating caused by the steam generator pressure plate pending permanent repairs. The Commission's final Order No. PSC-2020-0368-FOF-EI adopting the DOAH Recommended Order dispositively determined that the $16.1 million in disputed replacement fuel costs should not have been charged to DEF customers. On November 2, 2020, DEF filed a notice of administrative appeal to the Florida Supreme Court and a *Motion for Stay Pending Judicial Review* in this docket. In that motion, DEF asked the Commission under Rule 25-22.061(1), F.A.C., to grant DEF a stay from implementing the direction in that final order that DEF update its fuel factor calculations to reverse the prior collection of the disputed amounts. In response to the *Motion for Stay,* PCS joined with the Office of Public Counsel ("OPC") and the Florida Industrial Power Users Group ("FIPUG") in the *Consumer Parties' Joint Response to Motion for Stay*, filed November 9, 2020. That response explains that the mandatory stay provision of subsection (1) of the Rule is not applicable to fuel cost factor reconciliations, and that DEF has not satisfied the required test for receiving a discretionary stay of the order (i.e., there is no irreparable harm to DEF since the fuel clause will inevitably reflect the final outcome of its noticed appeal). Because DEF has not satisfied the requirements of Rule 25-22.061, F.A.C., PCS opposes the requested stay and asks that the Commission instruct DEF to reverse its prior collection of the disputed $16.1 million in replacement fuel costs through the fuel clause factor to be collected in 2021.

CONCLUSION

For the reasons set forth above, PCS urges the Commission to (1) reduce DEF's fuel cost recovery amounts for January 2021 through December 2021 by $16.1 million, plus interest, to credit the fuel clause recovery costs relating to the replacement power and de-rating costs due to the outage of Bartow Unit 4 in April 2017; and (2) adjust the fuel cost recovery factors to the extent that the reduction in allowed cost recovery reduces the fuel cost recovery factors for DEF.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing Statement of Issues and Brief has been furnished by electronic mail and/or U.S. Mail this 10th day of November, 2020, to the following:

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor ___/	DOCKET NO. 20200001-EI FILED: November 10, 2020

JOINT POST HEARING BRIEF OF THE OFFICE OF PUBLIC COUNSEL AND THE FLORIDA INDUSTRIAL POWER USERS GROUP

The Citizens of the State of Florida, through the Office of Public Counsel, ("OPC") and The Florida Industrial Power Users Group ("FIPUG") collectively the Joint Parties,[1] pursuant to the Order Establishing Procedure in this docket, Order No. PSC-2020-0041-PCO-EI, issued January 31, 2020, hereby submit this Joint Post Hearing Statement and Brief.

STATEMENT OF POSITION

The specific disputed issue related to Duke Energy Florida, LLC ("DEF" "Duke" or Company") is simple. Duke has over collected $16.1 million from its customers as a result of imprudently incurred replacement power costs. The Commission has determined that Duke operated the Bartow Unit 4 imprudently, and that Duke's imprudence caused both the full unit outage and subsequently resulted in a 40 MW degraded generator. Duke has conceded that that the replacement power costs for both circumstances total $16.1 million, before adding interest. On November 2, 2020, Duke filed a notice of appeal of Order No. PSC-2020-0368A-EI ("Bartow Order") and a motion seeking a stay of that order pending appeal. On November 9, 2020, OPC, FIPUG and PCS filed a Joint Response to DEF's Motion for Stay ("Joint Response") asking the Commission to deny the stay request on the basis that the cited rule does not apply to the fuel clause's self-correcting true-up mechanism.

Simply put, the customers want their money back, and they want it back now. The Commission has the power to order that the over collected money be included as a true-up in the calculation of the 2021 fuel factor, along with a reasonable estimate of interest (subject to true-up in a subsequent proceeding). The Commission should exercise this power.

[1] White Springs Agricultural Chemicals d/b/a PCS Phosphate ("PCS") is filing a separate brief. The Joint Parties concur in that brief.

<u>ISSUE 1</u>: What action should be taken in response to Commission Order No. PSC-2020-0368-FOF-EI regarding the Bartow Unit 4 February 2017 outage?

Joint Parties: **DEF should credit the 2021 fuel (along with a reasonable estimate of interest (subject to true-up in a subsequent proceeding)), to adjust for the prior overcollection of imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4. **

Argument

The customers of DEF respectfully request a return of the money they began overpaying in 2018. The Commission determined in the Bartow Order Duke's customers had incurred damages in the amount of $16.1 million in replacement power costs, which DEF has recovered from those customers in its adjusted and updated fuel factor charges collected in 2019 and 2020. Bartow Order at 18-21; 55-56. These damages are comprised of two elements. $11.1 million is attributable to the two-month period in 2017 when the entire Bartow unit was off-line. Another $5 million is attributable to the 40 MW de-rating of the unit that began in May 2017 and continued until mid- 2019, and was occasioned by the installation of a pressure plate that limited the output of the unit pending a more permanent repair to Bartow's damaged steam generator. Bartow Order at 18-21; 55-56.

In the Spring of 2017, after DEF had experienced the two-month outage at its Bartow Unit 4 (Steam Turbine) and installed the power limiting pressure plate, the Commission approved a stipulation between DEF and customer representatives in which DEF agreed it would not seek to recover the then estimated $11 million in replacement power costs associated with the outage. Instead, DEF agreed to record the estimated replacement fuel costs in an "over/under account" for future recovery in the fuel clause. This recovery occurred throughout the year 2019. TR 356.[2] DEF witness Menendez conceded that the "over/under account" preserved the Company's opportunity to recover the costs in a future period. TR 356-357. DEF's fuel factor calculations accordingly were lower in 2018 than its actual/estimated costs by $10.9 million because the Company

[2] Transcript references are to the transcript of the November 2, 2020 hearing in Docket No. 20200001-EI and shown as "TR __."

accounted for the unrecovered costs in the "over/under account" and not through its fuel clause cost recovery mechanism.

DEF witness Menendez testified in the fuel clause hearing this year that the Company was able to submit the 2017 outage replacement costs for clause recovery one year later because of the availability of the "over/under account." He described the true-up function of the account in this manner:

> The over/under account that is being referred to is otherwise known as the true-up balance, or the true-up variance.
>
> ***
>
> It is a variance between the revenues collected an [sic] the expense occurred [sic] in the clause account.

TR 355. This mechanism conclusively demonstrates that the fuel clause is self-correcting and adequately provides a mechanism for restoring the *status quo ante* on the chance that DEF may not have recovered the disputed replacement power costs addressed in the Bartow Order.

As noted, the outage costs were not the only costs at issue in the Bartow Order. In 2018, Duke began charging customers for replacement power costs attributable to the de-rating of the Bartow Unit 4 (steam turbine) that was determined by the Commission to have resulted from the 40 MW de-rating of the Steam Turbine. The de-rating of the Bartow unit occurred from May 2017 to September 2019. Order No. PSC-2020-0368A-EI ("Bartow Order") at 56; TR 358-361 (Bernier stipulation). There was no evidence that the replacement power costs that were required because of the de-rating were ever recorded in the "over/under account" since these costs were apparently never withheld from recovery or separately identified by DEF. TR 362. Regardless, DEF collected this money from its customers with no Commission review until the conduct of the hearing that was referred to DOAH in 2019. These funds were ruled to be imprudently collected. Now DEF is seeking to retain for up to 2-3 more years funds that were never expressly approved or even considered by the Commission in a reasonableness or prudence determination until the vote on September 1, 2020 denying recovery. What's more, collections of the replacement power costs began in 2017 and largely ended in 2019. Witness Menendez acknowledged that, if the credit is not made in the 2021 cycle and a stay is granted, customers would likely not begin to see their money returned until 2023 at the earliest and their money would not be fully returned until the end of 2023 in the likely event DEF fails to convince the Supreme Court that its version of the conclusions of law can be supported by the 102 contrary findings of facts to which the Company agreed.

As noted in the Joint Response, if a stay were to be granted (and it should not be), these customer dollars would not be restored until as much as five to six years after the customers originally began paying for the imprudently incurred costs. TR. 373 - 374. Of particular note is that 31% of the funds (related to de-rate costs) that the DEF asks the Commission to let it hold for another two to three years, have never been approved by the Commission as reasonable or prudent for recovery as replacement power costs. Customers have over-paid these Bartow outage and replacement power costs for years now and are entitled to a return of the funds now. As also noted in the Joint Response, the Consumers are willing to stipulate, if necessary, to accommodate the return of long overdue customer funds.[3] In short, there is no reason for the Commission to not direct that the 2021 fuel factor reflect the credit of $16.1 million. A reasonable estimate of interest can be added now and later adjusted in the true-up process, if necessary.

For the reasons stated herein and in the Joint Response, the Commission should expedite the return of long overdue overcollections of imprudently incurred replacement power costs.

<u>ISSUE 11</u>: What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2021 through December 2021?

Joint Parties: **The fuel cost recovery factors for 2021 should reflect an adjustment for the overcollection of $16.1 million (along with a reasonable estimate of interest (subject to true-up in a subsequent proceeding)) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.**

[3] The Consumers are willing to stipulate, if necessary (and we think it is not given the self-correcting true-up nature of the fuel clause), that DEF would be able to credit the clause with the $16.1 million (plus interest) for 2021 fuel factor purposes and correspondingly debit the "over/under account" in the same amount so that *if* DEF prevails on appeal, the process can be reversed and the "over/under account" would be credited and the fuel factor would be debited by the amount ordered collected from customers.

Argument

See argument on Issue 1B. This issue is a fallout issue that should reflect an adjustment for the overcollection of $16.1 million (plus reasonable interest) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.

<u>ISSUE 18</u>: What are the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2021 through December 2021?

Consumers: **The net fuel and purchased power cost recovery and Generating Performance Incentive amounts included in the recovery factor for 2021 should reflect an adjustment for the overcollection of $16.1 million (along with a reasonable estimate of interest (subject to true-up in a subsequent proceeding)) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.**

Argument

See argument on Issue 1B. This issue is a fallout issue that should reflect an adjustment for the overcollection of $16.1 million (plus reasonable interest) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.

<u>ISSUE 20</u>: What are the appropriate levelized fuel cost recovery factors for the period January 2021 through December 2021?

Consumers: **The levelized fuel cost recovery factors for the period January 2021 through December 2021 should reflect an adjustment for the overcollection of $16.1 million (along with a reasonable estimate of interest (subject to true-up in a subsequent proceeding)) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.**

Argument

See argument on Issue 1B. This issue is a fallout issue that should reflect an adjustment for the overcollection of $16.1 million (plus reasonable interest) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.

ISSUE 22: What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?

Consumers: **The allocation of fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses should reflect an adjustment for the overcollection of $16.1 million (along with a reasonable estimate of interest (subject to true-up in a subsequent proceeding)) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.**

Argument

See argument on Issue 1B. This issue is a fallout issue that should reflect an adjustment for the overcollection of $16.1 million (plus reasonable interest) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.

ISSUE 36: Should this docket be closed?

Consumers: *No. The docket should remain open until any action approved, if at all, by the Commission is completed satisfactorily.*

Dated this 10th day of November 2020.

Respectfully submitted,

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CERTIFICATE OF SERVICE
Docket No. 20200001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Joint Parties' Brief has been furnished by electronic mail on this 10th day of November 2020, to the following:

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FILED 11/10/2020
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FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor	Docket No. 20200001-EI Filed: November 10, 2020

DUKE ENERGY FLORIDA, LLC'S
POST-HEARING STATEMENT AND BRIEF

Duke Energy Florida, LLC ("DEF") hereby submits its Post-Hearing Statement of Issues, Positions, and Brief in this matter and states as follows:

I. Introduction

This Commission should approve DEF's requested fuel and capacity costs and DEF's proposed 2021 fuel and capacity cost recovery factors as filed. The sole remaining contested, substantive issue for the Commission's determination is Issue 1A: "What action should be taken in response to Commission Order No. PSC-2020-0368-FOF-EI-A[1] regarding the Bartow Unit 4 February 2017 outage?"[2] In DEF's Prehearing Statement, DEF took the position that no Commission action is appropriate at this time because any such action would be premature given that the Bartow Order was not rendered until October 15, 2020, approximately five weeks after DEF made its 2021 fuel and capacity cost projection filing. Subsequent to filing its Prehearing

[1] After the Issues were determined, but before the Prehearing Order issued in this docket, Order No. 2020-0368-FOF-EI was amended to include "Attachment A" – the ALJ's Recommended Order. Herein, the Order, as amended, will be referred to as the "Bartow Order."

[2] The Office of Public Counsel ("OPC"), Florida Industrial Power Users Group ("FIPUG"), and White Springs Agricultural Chemicals d/b/a PCS Phosphate ("PCS Phosphate"), have also contested fallout issues pertaining to Issue 1A, Issues 10, 11, 18, 20, and 22. The resolution of Issue 1A will determine the resolution of those remaining issues, thus they will be discussed together and collectively referred to as the "Bartow Issue."

Statement, DEF filed its Notice of Appeal and Motion for Stay Pending Judicial Review of the Bartow Order.[3]

II. <u>The Commission should Approve Recovery of DEF's Projected 2021 Fuel and Capacity Costs and Associated Fuel and Capacity Cost Recovery Factors</u>

As more thoroughly discussed in DEF's Motion for Stay Pending Judicial Review of the Bartow Order (the "Motion"),[4] which is hereby incorporated herein by reference, because the Bartow Order involves a refund to customers, DEF is entitled as a matter of law to a stay of the effectiveness of the Order pending judicial review. Rule 25-22.061(1), F.A.C. The Commission will consider the Motion and the response filed by the intervenor parties at its December 1, 2020, Agenda Conference.

Rule 25-22.061(1), F.A.C. (the "Rule"), clearly and unambiguously controls in this situation. This statement of Commission policy[5] provides that "[w]hen the order being appealed involves the ***refund of moneys to customers or a decrease in rates charged to customers***, the Commission ***shall***, upon motion filed by the utility or company affected, ***grant a stay*** pending judicial proceedings." (emphasis supplied). This Rule could not be clearer nor more on point.

While DEF respectfully disagrees with the ALJ's and Commission's determination that DEF was imprudent in its operation of the Bartow Plant, the Bartow Order unambiguously "involves the refund of moneys to customers" – indeed, Paragraph 125 of the ALJ's Recommended

[3] As mentioned in footnote 2, the Bartow Order has been amended, and DEF will amend its Notice of Appeal and Motion to Stay accordingly.

[4] *See* Document No. 11692-2020, Docket No. 20200001-EI, filed Nov. 2, 2020.

[5] *See* § 120.52(16), Fla. Stat. ("'Rule' means each agency statement of general applicability that implements, interprets, or prescribes law or policy or describes the procedure or practice requirements of an agency and includes any form which imposes any requirement or solicits any information not specifically required by statute or by an existing rule. . .").

Order, adopted by this Commission without modification,[6] states: "The total amount to be refunded to customers . . . is $16,116,782, without interest." Moreover, as DEF witness Mr. Menendez testified at hearing, if ultimately upheld on appeal, the refund would be delivered to customers as a decrease in the fuel rates charged to customers during the refund period. *See* Tr. Vol. II, p. 394, l. 24 – p. 395, l. 1. Thus, although one element of the Rule's requirement is phrased in the disjunctive (i.e., the Rule applies when the order under appeal involves *either* a refund of moneys *or* a decrease in rates), in this situation *both* are true. If upheld on appeal, the Bartow Order: 1.) involves a refund of moneys; and 2.) results in a decrease in rates. Clearly, whether the Bartow Order is construed to require a refund or a decrease in rates, the Rule applies, and the stay should be granted.

Simply put, the Commission is not permitted to make a case-by-case determination of when to apply the Rule, rather it "is obligated to follow its own rules." *See Vantage Healthcare Corp. v. Agency for Healthcare Admin.*, 687 So. 2d 306, 308 (Fla. 1st DCA 1997). The Intervenors attempt to read in a limitation that does not exist in the text of the Rule. The Intervenors argue "there is no evidence that the Commission intended the Rule to apply to the specialized true-up mechanism subsumed in the fuel clause." Of course, the opposite is true; there is no evidence the Commission ***did not*** intend the Rule to apply the cost recovery clauses. To the contrary, the absence of the limitation the Intervenors are seeking to graft onto the Rule is clear evidence that the Commission did not intend such a limitation to apply. Indeed, the Rule was amended in both 2010 and 2014. During those years, the Commission administered the Fuel and Capacity, Energy Conservation, Environmental, and Nuclear Cost Recovery Clauses. If the Commission had agreed

[6] Order No. PSC-2020-0368-FOF-EI, at p. 21 ("As set forth above, we deny all exceptions filed by DEF, approve all of the ALJ's findings of fact and conclusions of law without modification, and hereby adopt the ALJ's Recommended Order, found in Attachment A, as our Final Order.").

with the limitation now being offered, it could have taken action at that time to limit the applicability of the Rule to non-clause related Orders.

Furthermore, the Intervenors argue that the Rule is "surplusage" and an "anachronism that serves no purpose." Again, if the Commission agreed, it could have repealed the Rule in either 2010 or 2014, or at any other point since the Court rendered its decision in *GTE* in 1996.[7] The fact that it has opted not to do so clearly evinces the Commission's determination that its Rule still has merit and embodies sound regulatory policy.

Finally, the Intervenors' argument that DEF is picking and choosing by treating the stay provision and not the bond or corporate undertaking provisions of the Rule as mandatory is without merit and continues to ignore the Rule's plain language, which states:

> (1) ***When the order being appealed involves the refund of moneys to customers or a decrease in rates charged to customers, the Commission shall, upon motion filed by the utility or company affected, grant a stay pending judicial proceedings***. The stay shall be conditioned upon the posting of good and sufficient bond, the posting of a corporate undertaking, ***or such other conditions as the Commission finds appropriate*** to secure the revenues collected by the utility subject to refund.

Rule 25-22.061(1), F.A.C. (e.s.). The first sentence has three elements: 1.) an order being appealed; 2.) involving the refund of monies to customers or a decrease in rates charged to customers; and 3.) a motion to stay filed by the utility affected. Once the three elements are met, as they are here, the Rule is clear that the stay is mandatory. *Id.* ("the Commission ***shall . . . grant a stay pending judicial proceedings***.") (e.s.).[8] The second sentence of subsection (1) is different. It provides the Commission a range of options to secure the revenues necessary to make the refund if upheld on appeal. DEF is merely arguing that, given the nature of the fuel clause and the method

[7] *See GTE, Fla. v. Clark*, 668 So. 2d 971 (Fla. 1996).

[8] If the Commission had intended to provide itself discretion regarding granting or denying the stay when the elements of subsection (1) are met, it easily could have done so.

such a refund would take (a reduction in fuel rates in the refund year), no bond or undertaking is necessary to secure those funds. Such a determination is clearly within the Commission's discretion. *See id.* ("… ***or such other conditions as the Commission finds appropriate*** . . .") (e.s.).

If the Commission grants DEF's motion as required by Rule, *see Vantage*, and rules in DEF's favor on Issue 1A, because DEF has otherwise demonstrated the reasonableness of its proposed fuel and capacity costs and resulting recovery factors, the Commission should approve DEF's 2021 projected fuel recovery (Issue 11), DEF's 2021 fuel cost recovery factors (Issue 22), and all other remaining DEF issues (Issues 6-10, 16-21, 23A-D, and 27-36) as filed by DEF.

III. Post-Hearing Statement of Issues and Positions

As discussed at the Final Hearing, OPC, PCS Phosphate, and FIPUG, took "no position" on all Issues pertaining to DEF other than Issues 1A, 10, 11, 18, 20, and 22. Therefore, they have waived their right to contest DEF's positions on, or to brief, these Issues. Rather than reiterate DEF's position on each of the remaining Issues, DEF hereby adopts and Incorporates by Reference its positions on those Issues[9] as provided in the Pre-Hearing Order.[10]

Issue 1A: What action should be taken in response to Commission Order No. PSC-2020-0368-FOF-EI-A regarding the Bartow Unit 4 February 2017 outage?

No action should be taken at this time. The Commission should grant DEF's Motion for Stay Pending Judicial Review. Pursuant to Rule 25-22.061(1), F.A.C., upon motion by an affected utility, the Commission shall stay the effectiveness of any ordered refund or decrease in rates pending judicial review of the order.

[9] For clarity, the remaining DEF Issues are: 6-9, 16-17, 19, 21, 23A-D, and 27-36.

[10] Order No. PSC-2020-0415-PHO-EI.

Issue 10: What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2021 through December 2021?

$61,083,424 over-recovery.

Issue 11: What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2021 through December 2021?

$1,279,043,741, which is adjusted for line losses and excludes prior period true-up amounts, revenue taxes and GPIF amounts.

Issue 18: What are the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2021 through December 2021?

$1,223,244,961.

Issue 20: What are the appropriate levelized fuel cost recovery factors for the period January 2021 through December 2021?

3.090 cents/kWh (adjusted for jurisdictional losses).

Issue 22: What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?

Fuel Cost Factors (cents/kWh)						
					Time of Use	
Group	Delivery Voltage Level	First Tier Factor	Second Tier Factors	Levelized Factors	On-Peak	Off-Peak
A	Transmission	--	--	3.032	3.793	2.689
B	Distribution Primary	--	--	3.063	3.832	2.717

C	**Distribution Secondary**	**2.811**	**3.811**	**3.094**	**3.871**	**2.744**
D	**Lighting Secondary**	**--**	**--**	**2.955**	**--**	**--**

RESPECTFULLY SUBMITTED this 10th day of November, 2020.

/s/ Matthew R. Bernier
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CERTIFICATE OF SERVICE

Docket No. 20200001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 10th day of November, 2020.

/s/ Matthew R. Bernier
Attorney

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Matthew R. Bernier
ASSOCIATE GENERAL COUNSEL

November 17, 2020

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. 20200001-EI*

Dear Mr. Teitzman:

Please find enclosed for electronic filing on behalf of Duke Energy Florida, LLC ("DEF"), DEF's Request for Confidential Classification filed in connection with certain information provided in the Florida Public Service Commission's (FPSC) Amended Final Order No. PSC-2020-0368A-FOF-EI (DN 11601-2020). The filing includes the following:

- DEF's Request for Confidential Classification
- Slipsheet for confidential Exhibit A
- Exhibit B (two redacted copies)
- Exhibit C (Justification Matrix), and
- Exhibit D (Affidavit of Jeffrey Swartz)

DEF's confidential Exhibit A that accompanies the above-referenced filing has been submitted under separate cover.

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,

<u>/s/ Matthew R. Bernier</u>

Matthew R. Bernier

MRB/cmw
Enclosure

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery Clause with generating performance incentive Factor

Docket No. 20200001-EI

Filed: November 17, 2020

DUKE ENERGY FLORIDA, LLC'S
<u>REQUEST FOR CONFIDENTIAL CLASSIFICATION</u>

Duke Energy Florida, LLC, ("DEF" or "Company"), pursuant to Section 366.093, Florida Statutes (F.S.), and Rule 25-22.006, Florida Administrative Code (F.A.C.), submits this Request for Confidential Classification for certain information provided in the Florida Public Service Commission's (FPSC) Amended Final Order No. PSC-2020-0368A-FOF-EI (DN 11601-2020). This Request is timely. *See* Rule 25-22.006(3)(a)1, F.A.C. In support of this Request, DEF states:

The FPSC's Amended Final Order No. PSC-2020-0368A-FOF-EI, contains "proprietary confidential business information" under § 366.093(3), Florida Statutes.

1. The following exhibits are included with this request:

(a) Sealed Composite Exhibit A is a package containing an unredacted copy of all the documents for which DEF seeks confidential treatment. Composite Exhibit A was submitted separately in a sealed envelope labeled "CONFIDENTIAL" on November 18, 2020. In the unredacted version, the information asserted to be confidential is highlighted in yellow.

(b) Composite Exhibit B is a package containing two copies of redacted versions of the documents for which the Company requests confidential classification, or slip sheets for documents which are confidential in their entirety. The specific information for which confidential treatment is requested has been blocked out by opaque marker or other means.

(c) Exhibit C is a table which identifies the information for which DEF seeks confidential classification and the specific statutory bases for seeking confidential treatment.

(d) Exhibit D is an affidavit attesting to the confidential nature of information identified in this request.

2. As indicated in Exhibit C, the information for which DEF requests confidential classification is "proprietary confidential business information" within the meaning of § 366.093(3), F.S. DEF is requesting confidential classification of this information because it contains contractual information or information provided by a third party that DEF is obligated to keep confidential, the disclosure of which would harm its competitive business interest and ability to contract for goods or services on favorable terms. *See* §§ 366.093(3)(d) & (e), F.S.; Affidavit of Jeffrey Swartz at ¶¶ 3, 4 and 5. Accordingly, such information constitutes "proprietary confidential business information" which is exempt from disclosure under the Public Records Act pursuant to § 366.093(1), F.S.

3. In order to contract with third-party vendors and Original Equipment Manufacturers on favorable terms, DEF must keep contractual terms and third-party proprietary information confidential. The disclosure of which would be to the detriment of DEF and its customers. Additionally, the disclosure of confidential information provided by a third party could adversely impact DEF's competitive business interests. If such information was disclosed to DEF's competitors, DEF's efforts to obtain competitive contracts that add economic value to both DEF and its customers could be undermined. *See* Affidavit of Swartz at ¶¶ 4 and 5. *Id.*

4. The information identified as Exhibit "A" is intended to be and is treated as confidential by the Company. *See* Affidavit of Swartz at ¶¶ 4 and 6. The information has not

been disclosed to the public, and the Company and third-party vendors have treated and continue to treat this information as confidential. *Id.*

5. DEF requests that the information identified in Exhibit A be classified as "proprietary confidential business information" within the meaning of § 366.093(3), F.S., that the information remains confidential for a period of at least 18 months as provided in § 366.093(4) F.S., and that the information be returned as soon as it is no longer necessary for the Commission to conduct its business.

WHEREFORE, for the foregoing reasons, DEF respectfully requests that this Request for Confidential Classification be granted.

RESPECTFULLY SUBMITTED this 17th day of November, 2020.

/s/ Matthew R. Bernier

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CERTIFICATE OF SERVICE
Docket No. 20200001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 17th day of November, 2020.

/s/ Matthew R. Bernier
Attorney

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Exhibit A

CONFIDENTIAL

(Slipsheet: The confidential documents have been provided under separate cover.)

Exhibit B

(Two Copies)

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evidence. The revised Comprehensive Exhibit List (CEL) was admitted into evidence by stipulation as Exhibit No. 114.

A three-volume transcript of the final hearing was filed with the Commission Clerk on February 18, 2020, and was provided to the DOAH Clerk on February 24, 2020. DEF, Commission staff, and OPC, jointly with PCS Phosphate and FIPUG, timely filed confidential proposed recommended orders on March 20, 2020. The ALJ issued his Recommended Order[2] on April 27, 2020. A redacted version of the Recommended Order is found in Attachment A to this Final Order.

C. Overview of the Recommended Order

This case involves the operation of DEF's Bartow Unit 4 combined cycle natural gas plant and whether DEF operated the plant prudently from the time it was brought on line in June 2009 until February 2017. Bartow Unit 4 is comprised of a steam turbine manufactured by Mitsubishi Hitachi Power Systems (Mitsubishi) with a gross output of 420 MW connected to four M501 Type F combustion turbines. The steam turbine is an "after-market" unit which was originally designed for Tenaska Power Equipment, LLC (Tenaska) to be used in a 3x1 configuration with three M501 Type F combustion turbines with a gross output of 420 MW. Prior to purchasing the steam turbine, DEF's predecessor, Progress Energy Florida, LLC contracted with Mitsubishi to [redacted] As required by its contract, [redacted]

The Bartow plant has experienced five outages since it was brought on line in June 2009: March 2012 (planned), August 2014 (planned), April 2016 (planned), October 2016 (forced), and February 2017 (forced).

In March 2012 during a scheduled outage, DEF discovered that the [redacted] in the low pressure section of the steam turbine were damaged. The [redacted] were replaced with [redacted] and the plant was operated until August 2014 when the plant was taken out of service to [redacted] the [redacted]. The plant came back on line in December 2014 and ran until April 2016 when it was taken off line for routine valve work and [redacted] inspection. The plant was placed back in service in May 2016 with a [redacted] and operated until October 2016, when DEF shut the plant down due to excessive vibration and loss of [redacted] material. In December 2016 the plant was put back in service with the [redacted], and was taken out of service in February of 2017 due to a [redacted] projectile that traveled through the low pressure turbine rupture disk diaphragm. DEF brought the plant back on line in April 2017 with a pressure plate installed in the low pressure section of the steam turbine, which effectively decreased the output of the plant from 420 to 380 MW. DEF continued to operate the plant with the pressure plates until September 28, 2019.

[2] "Recommended Order" is defined in Section 120.52(15), F.S., as the official recommendation of the ALJ assigned by DOAH or of any other duly authorized presiding officer, other than the agency head or member thereof.

There are two amounts that are associated with the initial prudence question: 1) replacement power costs for the February 2017 outage in the amount of $11.1 million, and 2) May 2017 through September 2019 unit derating[3] costs in the amount of $5,016,782 million.

Petitioner, DEF, has the burden of proving by a preponderance of the evidence, that it acted prudently in the operation of Bartow Unit 4 up to and restoring the unit to service after the February 2017 forced outage. Additionally, DEF must prove by a preponderance of the evidence that no adjustment to replacement power costs should be made to account for the fact that after March 2017, and the installation of a pressure plate, Bartow Unit 4 could no longer produce its rated nameplate capacity of 420 MW. The standard for determining whether replacement power costs are prudent is "what a reasonable utility manager would have done, in light of the conditions and circumstances that were known, or should [have] been known at the time the decision was made."[4]

In his Recommended Order, the ALJ detailed the relevant facts and legal standards required to determine whether DEF acted prudently in its operation of Bartow Unit 4 from June 2009 until February 2017. In his conclusion, the ALJ recommended that this Commission find that DEF failed to demonstrate that it acted prudently in the operation of its Bartow Unit 4 plant and in restoring the unit to service after the February 2017 forced outage, and that DEF should refund a total of $16,116,782 to its customers.

D. Post-Hearing proceedings before the Commission

On May 12, 2020, DEF submitted exceptions to the Recommended Order. OPC, jointly with PCS Phosphate and FIPUG (collectively, the Intervenors), filed a Response to DEF's Exceptions.

We have Jurisdiction over this matter under Sections 120.57, 366.04, 366.05, and 366.06, F.S. As discussed in more detail below, we deny DEF's Exceptions to the Recommended Order and adopt the Administrative Law Judge's Recommended Order as the Final Order.

II. RULINGS ON EXCEPTIONS

A. Standard of Review of Recommended Order and Exceptions

Section 120.57(1)(l), F.S., establishes the standards an agency must apply in reviewing a Recommended Order following a formal administrative proceeding. The statute provides that the agency may adopt the Recommended Order as the Final Order of the agency or may modify or reject the Recommended Order. An agency may only reject or modify an ALJ's findings of fact if, after a review of the entire record, the agency determines and states with particularity that the

[3] "Derating" is the reduction in MW output due to installing pressure plates in place of the [redacted] in the low pressure section of the steam turbine.
[4] *Southern Alliance for Clean Energy v. Graham*, 113 So. 3d 742, 750 (Fla. 2013).

findings of fact were not based on competent substantial evidence or that the proceedings on which the findings were based did not comply with the essential requirements of law.[5]

Section 120.57(1)(l), F.S., also states that an agency in its final order may reject or modify conclusions of law over which it has substantive jurisdiction and interpretations of administrative rules over which it has substantive jurisdiction. When rejecting or modifying a conclusion of law or interpretation of administrative rule, the agency must state with particularity its reasons for rejecting or modifying the conclusion of law or interpretation of administrative rule and must make a finding that its substituted conclusion of law or interpretation of administrative rule is as or more reasonable than that which was rejected or modified. Rejection or modification of conclusions of law may not form the basis for rejection or modification of findings of fact.[6]

In regard to parties' exceptions to the ALJ's Recommended Order, Section 120.57(1)(k), F.S., provides that the Commission does not have to rule on exceptions that fail to clearly identify the disputed portion of the Recommended Order by specific page numbers or paragraphs or that do not identify the legal basis for the exception, or those that lack appropriate and specific citations to the record.[7] Section 120.57(1)(l), F.S., requires our final order to include an explicit ruling on each exception and sets a high bar for rejecting an ALJ's findings.

B. Rulings on Exceptions to the Recommended Order

DEF Exception to Conclusion of Law 110

DEF takes exception with the ALJ's Conclusion of Law 110, which states:

> 110. DEF failed to demonstrate by a preponderance of the evidence that its actions during Period 1 were prudent. DEF purchased an aftermarket steam turbine from Mitsubishi with the knowledge that it had been manufactured to the specifications of Tenaska with a design point of 420 MW of output. Mr. Swartz's testimony regarding the irrelevance of the 420 MW limitation was unpersuasive in light of the documentation that after the initial blade failure, DEF itself accepted the limitation and worked with Mitsubishi to find a way to increase the output of the turbine to [redacted]

First, as a general criticism, DEF argues that when weighing the facts presented at hearing, although stating the correct legal standard of review what a reasonable utility manager should have done based on what he knew or should have known at the time - the ALJ did not apply that standard but instead evaluated DEF's actions from the perspective of what is currently known. DEF states that this type of "hindsight" and "Monday-morning quarterbacking" prudence analysis has been found to be inappropriate under *Florida Power Corporation v. Public Service Comm. (Florida Power),* 456 So. 2d 451, 452 (Fla. 1984).

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[5] Section 120.57(1)(l), F.S.
[6] *Id.*
[7] Section 120.57(1)(k), F.S.

Second, DEF disagrees with the ALJ's conclusion that the 420 MW design point was a limitation on the steam turbine. DEF argues that the record supports the conclusion that the 420 MW design point is a fall out number based on various combinations of operating parameters provided by Mitsubishi. DEF argues that operating within the [redacted] was prudent given what DEF knew or should have known during Period 1. At that time, DEF contends that there was no reason to believe that increasing the output above 420 MW would damage the unit [redacted] Thus, DEF concludes that the fact that the [redacted] failed in February 2017 does not mean that the plant operator reasonably should have known that would happen in June 2009.

Third, DEF argues that DEF's compliance with lower than 420 MW output after Period 1 and its request to Mitsubishi for modifications to operate the unit at [redacted] do not logically support the conclusion that DEF agreed the unit originally could not be operated above 420 MW. These actions, according to DEF, allowed the unit to continue to be operated to produce the most power possible while research into the cause of the Period 1 outage was conducted. DEF argues that getting the unit back on line producing as much power as possible is implementation of long standing Commission policy that utilities operate generating units for maximum efficiency. DEF asserts that these actions are not evidence of DEF's acceptance of 420 MW as a limitation on the output of the unit.

Intervenors' Response

Intervenors contend that DEF, while conceding that the ALJ referenced the correct legal standard for prudence review, never explains or demonstrates exactly how the ALJ applied "Monday-morning quarterbacking" to reach any of the conclusions in Conclusions of Law 110. In the determination of what a utility knew or should have known at any past point in time, Intervenors state that there is necessarily a review of contemporaneous prior actions and documents. They contend that that review was done here. Intervenors note that DEF has not argued that there is no competent substantial evidence supporting the ALJ's conclusions in Conclusions of Law 110 and cites nine separate parts of the record that do logically support the ALJ's conclusion that DEF did not act prudently in running the unit above 420 MW in Period 1.

Intervenors further argue that the *Florida Power* case relied upon by DEF is not applicable here for several reasons. In *Florida Power*, the Commission classified "non-safety related" repair work as "safety-related" repair work and then applied the higher standard of care for "safety-related" repair work to determine if Florida Power had conducted the repairs prudently. Finding that the record indicated that the extensive repair work was not *per se* safety-related, the Court found that the Commission could not apply the higher standard of care. *Florida Power,* 456 So. 2d at 451. Intervenors argue that in this case, the facts upon which the ALJ relied regarding the repair of the unit are supported by competent substantial evidence and are not in dispute, nor does DEF argue that the inferences drawn from the facts by the ALJ are unreasonable. Intervenors state that DEF would simply draw different conclusions from the same set of facts, i.e., would have us weigh the evidence differently, an action prohibited by Chapter 120, F.S.

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were relied upon by the ALJ in reaching his conclusion of imprudence. Without identifying the facts upon which the ALJ improperly relied, it is impossible to evaluate this contention and it is rejected.

The ALJ bases his conclusion that a preponderance of the evidence established the actions of DEF in Period 1 were imprudent on three facts. First, the Mitsubishi aftermarket steam turbine was manufactured with a design point of 420 MW of output. Second, witness Swartz's testimony that the 420 MW was not an operational limitation was unpersuasive. Third, DEF accepted this limitation in Periods 2-5 and [redacted]

With regard to the first point, DEF does not contest that the steam turbine was aftermarket manufactured with a design point of 420 MW. This conclusion is supported by Findings of Fact Nos. 14-26. With regard to the second point, the ALJ extensively discusses the arguments presented by DEF witness Swartz that the 420 MW is not an operational limitation for this steam turbine in Findings of Fact Nos. 16-32 which culminate in Finding of Fact No. 33. Finding of Fact No. 33, a finding that DEF did not contest, states: "The greater weight of the evidence establishes that the Mitsubishi steam turbine was designed to operate at 420 MW of output and that 420 MW was an operational limitation of the turbine." Since DEF did not take exception to the identical statement in Finding of Fact No. 33, DEF has waived its ability to contest Conclusion of Law 110 on the grounds that the design point did not act as an operational limitation. However, even if DEF had taken exception to Finding of Fact 33, it is clear that the ALJ considered and rejected witness Swartz's arguments that DEF did not act imprudently by operating the steam turbine for extended periods of time at more than 420 MW.

With regard to the third point, DEF does not dispute that in Periods 2-5 it complied with the lower operating limitations placed on it by Mitsubishi and worked with Mitsubishi to increase the steam turbine's output to [redacted]. DEF disputes the significance of having done so. DEF argues that by [redacted] in Periods 2-5 it was acting to maximize the steam turbine's output for the benefit of its customers. As a general matter, DEF has argued that if a conclusion of law is "infused with overriding policy considerations," the agency, not the ALJ, should decide that issue.[12] Although not specifically identified, apparently, DEF believes that "maximization of output" is such an "overriding policy consideration" which should be given agency deference when determining operational prudence. However, DEF has not identified any statute, rule or Commission order that identifies "maximization of output" as a Commission policy. Additionally, the idea of agency deference, even in the interpretation of an agency's own rules and statutes, is now highly questionable given the passage of Amendment 6 to the Florida Constitution.[13]

[12] *Pillsbury v. State, Department of Health & Rehabilitative Services,* 744 So. 2d 1040, 1042 (Fla. 2d DCA 1999).
[13] "Section 21. Judicial interpretation of statutes and rules. – In interpreting a state statute or rule, a state court or an officer hearing an administrative action pursuant to general law may not defer to an agency's interpretation of such statute or rule, and must instead interpret such statute or rule de novo."

REDACTED

Additionally, we do not find the *Florida Power* decision cited by DEF on the issue of hindsight to be relevant. In *Florida Power*, the Commission made a finding of fact that was not supported by the record - that "non- safety related" repair work was "safety-related" repair work - and then improperly applied the higher standard of care for "safety-related" repair work. The crux of the problem in *Florida Power* was this unsupported finding of fact. Here DEF is not contesting any of the ALJ's 102 findings of fact as being unsupported by competent substantial evidence. Nor is DEF arguing that the legal conclusions the ALJ has drawn from these uncontested facts are unreasonable. Here there is no mistake of fact triggering the misapplication of a legal standard. In this case all parties agree on the standard to be applied, DEF simply does not like the result reached by the ALJ.

Because DEF has failed to establish that its exception to Conclusion of Law 110 is as or more reasonable that that of the ALJ, DEF's Exception to Conclusion of Law 110 is denied.

DEF Exception to Conclusion of Law 111

DEF takes exception with the ALJ's Conclusion of Law 111, which states:

> 111. DEF's RCA [Root Cause Analysis] concluded that the blade failures were caused [redacted] This conclusion is belied by the fact that [redacted] Mitsubishi cannot be faulted for [redacted] in a way that would allow an operator to run the turbine consistently beyond its capacity.

DEF takes exception to the conclusion that the [redacted] were not caused by [redacted] DEF argues that Mitsubishi was contracted specifically to assess whether this particular steam turbine could handle the proposed 4x1 steam configuration. DEF states that Mitsubishi did not originally identify [redacted] as a potential problem and it was reasonable for DEF in Period 1 to rely upon Mitsubishi's assessment. The better comparison, according to DEF, is not with other Mitsubishi facilities, but with blade failures in Periods 2-5 when the unit was run at less than 420 MW. Finally, DEF notes that the exact time that the [redacted] were damaged in Period 1 cannot be established. DEF states that the damage could have occurred during the half of the time in Period 1 when the steam turbine was operated at less than 420 MW.

Intervenors' Response

Intervenors respond that the conclusions of law in Paragraph 111 are supported by competent substantial evidence of record. Further, to the extent that a finding is both a factual and legal conclusion, Intervenors state that it cannot be rejected when there is competent substantial evidence to support the conclusion and the legal conclusion necessarily follows. *Berger*, 653 So. 2d at 480; *Strickland*, 799 So. 2d at 279; *Dunham*, 652 So. 2d at 897. Additionally, Intervenors contend that it is the ALJ, not the Commission, who is authorized to interpret the evidence presented and to decide between two contrary positions supported by conflicting evidence. *Heifetz v. Dept. of Business Regulation,* 475 So. 2d 1277, 1281-2 (Fla. 1st DCA 1985). With regard to DEF's reliance on the fact that it is impossible to tell when the [redacted] were damaged in Period 1, Intervenors find this to be irrelevant since the ALJ does not address that fact in Paragraph 111.

Ruling

This conclusion of law constitutes the ALJ's rejection of DEF's Root Cause Analysis (RCA) conclusion that the low pressure steam turbine 40" [redacted].[14] [redacted][15] [redacted][16] Given these facts, none of which are disputed by DEF, the ALJ found DEF's exclusion of [redacted] from its final RCA to be troubling, as does this Commission.

The ALJ's Conclusion of Law was adequately supported by the relevant findings of fact. DEF has failed to demonstrate that its conclusion is as or more reasonable than that of the ALJ. For this reason, DEF's Exception to Conclusion of Law 111 is denied.

DEF Exception to Conclusion of Law 112

DEF takes exception with the ALJ's Conclusion of Law 112, which states:

> 112. [redacted]

DEF states that Mitsubishi did not ultimately attribute the [redacted] DEF argues that given the fact that the turbine was not operated above 420 MW in Periods 2 through 5, it is more reasonable to conclude that the damage to the [redacted] in Period 1 was the result of [redacted]

[14] Finding of Fact No. 67.
[15] Finding of Fact No. 83.
[16] Finding of Fact No. 70.

Intervenors' Response

Intervenors contend that DEF does not contest that there are findings of fact supported by competent substantial evidence in the record to support the ALJ's conclusion of law. Thus, Intervenors conclude that, under those circumstances, we cannot reject the ALJ's conclusion of law or substitute its own judgment for that of the ALJ.

Ruling

This conclusion of law constitutes the ALJ's acceptance of Mitsubishi's RCA which concluded [redacted][17] [redacted][18] [redacted][19].

DEF is simply rearguing its case that its RCA should be substituted for that of Mitsubishi. DEF has not contested the facts upon which Conclusion of Law 112 is based. Conclusion of Law 112 is the companion to Conclusion of Law 111 and it is upheld for the same reasons – that there is competent substantial evidence to support this conclusion and the conclusion is reasonable given the facts proven by a preponderance of the evidence presented. DEF has failed to demonstrate that its conclusion is as or more reasonable than that of the ALJ. Thus, DEF's Exception to Conclusion of Law 112 is denied.

DEF Exception to Conclusion of Law 113

DEF takes exception with the ALJ's Conclusion of Law 113, which states:

> 113. Mr. Polich persuasively argued that it would have been simple prudence for DEF to ask Mitsubishi about the ability of the turbine to operate continuously in excess of 420 MW output before actually operating it at those levels. DEF understood that the blades had been designed for the Tenaska 3x1 configuration and should have at least explored with Mitsubishi the wisdom of operating the steam turbine with steam flows in excess of those anticipated in the original design.

[17] Finding of Fact Nos. 37, 63.
[18] Finding of Fact No. 70.
[19] Finding of Fact No. 78.

REDACTED

DEF defends not contacting Mitsubishi by citing the followin g evidence in the record: 1) [redacted] 2) the MW output of a steam turbine is not an "operating parameter"; and 3) Mitsubishi knew DEF would operate the plant in excess of 420 MW. For these reasons, DEF argues that it is "as or more reasonable" to conclude that DEF did not need to contact Mitsubishi.

Intervenors' Response

Intervenors argue that DEF is simply rehashing the evidence presented and urging this Commission to make new findings that are "as or more reasonable" than the findings made by the ALJ. The ALJ states that he found OPC's expert persuasive on this point and it is the exclusive prerogative of the ALJ, not the Commission, to evaluate the credibility of a witness and the weight to be given to his/her testimony. Intervenors contend that since there is competent substantial evidence supporting the conclusion that DEF should have called Mitsubishi, this conclusion cannot be modified.

Ruling

When viewed as a whole, the ALJ has based his analysis of this case by focusing on several areas. [redacted] Second, the type and meaning of [redacted] Third, the cause of the damage to the low pressure [redacted] Analysis of these three areas results in a finding regarding whether DEF acted prudently in the operation of the steam turbine which in turn drives the decision of whether replacement power costs for the April 2017 outage should be recovered or denied.

The ALJ's findings of fact establish that the steam turbine was originally designed to be used in a 3x1 configuration with a design point maximum of 420 MW. The 3x1 configuration used three M501 Type F combustion turbines connected to the steam turbine.[20] The 4x1 design configuration used by DEF used four M501 Type F combustion turbines connected to the same steam turbine.[21] Section 3.2.1 of the original Purchase Agreement[22] clearly states [redacted].[23] [redacted][24]

[20] Finding of Fact No. 14.
[21] Finding of Fact No. 6.
[22] Entitled the [redacted] executed between Florida Progress and Mitsubishi.
[23] Finding of Fact No. 26.
[24] Finding of Fact No. 87.

Under these circumstances it is reasonable to believe that Mitsubishi would have [redacted][25] This is especially true since DEF was proposing the use of an additional 501 Type F combustion turbine and heat recovery steam generator, giving DEF's proposed configuration the ability to produce far more steam than needed to generate 420 MW of output when compared to the original 3x1 application for which the steam turbine was designed.[26] Additionally, neither DEF nor Mitsubishi had any experience running a 4x1 combined cycle plant prior to commencing operation of Bartow Unit 4.[27] In sum, for these reasons the ALJ found that Mitsubishi did not contemplate DEF's operation of the steam turbine beyond the [redacted] set out in the Purchase Agreement.[28]

Given these extremely unique circumstances, the ALJ concluded that DEF's failure to contact Mitsubishi before pushing output beyond 420 MW was not prudent. Contacting Mitsubishi would have allowed DEF to receive written verification from Mitsubishi that the steam turbine could be safely operated above 420 MW and would have effectively updated the warranty to reflect the higher MW output.[29] The ALJ's conclusion of law is supported by competent substantial evidence of record. Because DEF has failed to demonstrate that its conclusion of law is as or more reasonable than the ALJ's, DEF's Exception to Conclusion of Law 113 is denied.

DEF Exception to Conclusion of Law 114

DEF takes exception with the ALJ's Conclusion of Law 114, which states:

> 114. The record evidence demonstrated an [redacted] that vibrations associated with high energy loadings were the primary cause of the L-0 blade failures. DEF failed to satisfy its burden of showing its actions in operating the steam turbine in Period 1 did not cause or contribute significantly to the vibrations that repeatedly damaged the L-0 blades. To the contrary, the preponderance of the evidence pointed to DEF's operation of the steam turbine in Period 1 as the most plausible culprit.

DEF argues that it is "as or more reasonable" to conclude from the evidence presented that DEF's actions did not cause or contribute significantly to the [redacted] DEF contends this is true because the [redacted] were damaged in Periods 2-5 when the unit was not run above 420 MW as well as Period 1 when it was. DEF further states that the ALJ is imposing the impossible standard of proving a negative. DEF argues that it does not have the burden to prove that damage did not occur as a result of its actions. Rather, DEF states that it is only required to show that it acted as a reasonable utility manager would have done given the facts known or reasonably knowable at the time without the benefit of hindsight review.

[25] Finding of Fact No. 87.
[26] Finding of Fact No. 31.
[27] Finding of Fact No. 85.
[28] Finding of Fact No. 102.
[29] Factual Finding No. 93.

REDACTED

Intervenors' Response

Intervenors argue that Conclusion of Law 114 summaries the findings of fact that support the ALJ's ultimate determination. Intervenors state that these findings of fact are supported by competent substantial evidence and we may not reject them. With regard to the contention that the ALJ required DEF to prove a negative, Intervenors argue that DEF has the burden of proof to demonstrate that it acted prudently in the operation of Bartow Unit 4 which requires it to establish a *prima facie* case that it did act prudently and to rebut evidence of its imprudence. The Intervenors assert that DEF did neither here and the ALJ's conclusion may not be disturbed.

Ruling

As discussed in the ruling on Conclusions of Law 110-113 above, the ALJ found that a preponderance of the evidence supported the finding that the [redacted] was caused by vibrations/flutter associated with high energy loadings. Further, the ALJ found that the weight of the evidence supported the conclusion that the high energy loading on the blades was the result of [redacted]. DEF does not contest that these findings of fact are supported by competent substantial evidence of record.

We agree with the ALJ that DEF has the burden of proving that it acted prudently in the operation of its steam turbine, i.e., the burden to make a *prima facie* case supported by competent substantial evidence that it acted prudently. The burden of proof also requires DEF to rebut evidence produced that it acted imprudently. Here under the unique circumstances of this case, DEF has failed to prove it acted prudently in light of the information that was available to it at the time as found by the ALJ in Conclusion of Law 110. DEF's exception to Conclusion of Law 114 reargues DEF's factual position and fails to demonstrate that its conclusion is as or more reasonable than the ALJ's. For these reasons, DEF's Exception to Conclusion of Law 114 is denied.

DEF Exception to Conclusion of Law 119

DEF takes exception with the ALJ's Conclusion of Law 119, which states:

> 119. It is speculative to state that the original Period L-0 blades would still be operating today had DEF observed the [redacted] of 420 MW. It is not speculative to state that the events of Periods 2 through 5 were precipitated by DEF's actions during Period 1. It is not possible to state what would have happened from 2012 to 2017 if the excessive loading had not occurred, but it is possible to state that events would not have been the same.

Specifically, DEF disputes the ALJ's conclusion that it is not speculative to state that the events of Periods 2 through 5 were precipitated by DEF's actions during Period 1. DEF argues that there is no causal link between the operation of the unit in Period 1 and the forced outage that occurred in Period 5. DEF contends that the lack of a causal link is proven by the fact that there was no residual damage done to the steam turbine itself in Period 1 and all parties agreed that DEF's operation of the plant subsequent to Period 1 was prudent.

Intervenors' Response

Intervenors state that the conclusions in Paragraph 119 are based on the ALJ's findings of fact in Paragraphs 84 and 89 which are supported by competent substantial evidence and OPC's expert's credible testimony. Intervenors argue that to the extent that this conclusion is an inference from the ALJ's factual findings, the ALJ is permitted to draw reasonable inferences from competent substantial evidence in the record. *Amador v. School Board of Monroe County*, 225 So. 3d 853, 858 (Fla. 3d DCA 2017). Further, Intervenors state that the fact that more than one reasonable inference can be drawn from the same evidence of record is not grounds for setting aside the ALJ's conclusion. *Id.*

Ruling

This conclusion of law is in response to OPC witness Polich's testimony that the low pressure [redacted] would still have been in use but for the operation of the steam turbine in excess of 420 MW.[30] While the ALJ rejected that conclusion as too speculative, he did accept witness Polich's testimony that the damage to the blades was most likely cumulative during Period 1, making it irrelevant exactly when during the operation of the unit in Period 1 the damage occurred.[31] DEF's witness Swartz testified that the damage to the blades could have occurred in Period 1 during the 50% of the time that the steam turbine was operated under 420 MW, i.e., when by Intervenors' standards, the unit was being operated prudently. Where reasonable people can differ about the facts, an agency is bound by the hearing officer's reasonable inferences based on the conflicting inferences arising from the evidence. *Amador v. School Board of Monroe County*, 225 So. 3d 853, 857-8 (Fla. 3d DCA 2017). Additionally, the hearing officer is entitled to rely on the testimony of a single witness even if the testimony contradicts the testimony of a number of other witnesses. *Stinson v. Winn*, 938 So. 2d 554, 555 (Fla. 1st DCA 2006).

DEF's exception to Conclusion of Law 119 reargues DEF's factual position and fails to demonstrate that its conclusion is as or more reasonable than the ALJ's. For these reasons, DEF's Exception to Conclusion of Law 119 is denied.

DEF Exception to Conclusion of Law 120

DEF takes exception with the ALJ's Conclusion of Law 120, which states:

> 120. In his closing argument, counsel for White Springs summarized the equities of the situation very well:

[30] Finding of Fact No. 84.
[31] Finding of Fact No. 89; Footnote 4.

> You can drive a four-cylinder Ford Fiesta like a V8 Ferrari, but it's not quite the same thing. At 4,000 RPMs, in second gear, the Ferrari is already doing 60 and it's just warming up. The Ford Fiesta, however, will be moaning and begging you to slow down and shift gears. And that's kind of what we're talking about here.
>
> It's conceded as fact that the root cause of the Bartow low pressure turbine problems is [redacted] caused repeatedly over time. The answer to the question is was this due to the way [DEF] ran the plant or is it due to a [redacted] Well, the answer is both.
>
> The fact is that [DEF] bought a steam turbine that was already built for a different configuration that was in storage, and then hooked it up to a configuration . . . that it knew could produce much more steam than it needed. It had a generator that could produce more megawatts, so the limiting factor was the steam turbine.
>
> On its own initiative, it decided to push more steam through the steam turbine to get more megawatts until it broke.
>
> * * *
>
> So from our perspective, [DEF] clearly was at fault for pushing excessive steam flow into the turbine in the first place. The repair which has been established . . . may or may not work, but the early operation clearly impeded [DEF's] ability to simply claim that Mitsubishi was entirely at fault. And under those circumstances, it's not appropriate to assign the cost to the consumers.

DEF argues that Conclusion of Law 120 is a slightly edited, verbatim recitation of PCS Phosphate counsel's final argument which the ALJ adopts, characterizing it as summarizing "the equities of the situation very well." DEF takes exception to that portion of the final argument stating that under the circumstances presented in this case, it is not appropriate to assign the cost of the February 2017 forced outage to DEF's customers. DEF argues that it is as or more reasonable to conclude that here, where DEF consistently acted prudently, DEF should not be forced to bear replacement power costs.

<u>Intervenors' Response</u>

As demonstrated in its response to Paragraphs 110-114 above, Intervenors argue that there is more than adequate competent substantial evidence to support the ALJ's ultimate determination that DEF did not act prudently and should bear replacement power costs. Intervenors state that DEF is simply rearguing the case it presented to the ALJ which the ALJ found to be unpersuasive.

Ruling

As noted above, this conclusion of law is an edited version of PCS Phosphate counsel's final argument which the ALJ agrees has summarized the "equities of the situation very well." [redacted] Further, whether the vibration was due to the way the plant was run or [redacted] is that both are true. The ALJ concludes that DEF was at fault for pushing excessive steam flow into the turbine. The ALJ further agrees that by operating the unit above 420 MW, without contacting Mitsubishi, DEF impeded its ability to claim that Mitsubishi was entirely at fault. Under these circumstances, PCS Phosphate's counsel, and the ALJ, conclude that consumers should not bear replacement power costs.

Upon review of this material, it is clear that it is a summary of Conclusions of Law 110-114 above. These conclusions are supported by competent substantial evidence of record. Again, DEF reargues the factual underpinnings of the ALJ's Conclusion of Law without adequately demonstrating that DEF's conclusion is as or more reasonable. Therefore, DEF's Exception to Conclusion of Law 120 is denied.

DEF Exception to Conclusion of Law 121

DEF takes exception with the ALJ's Conclusion of Law 121, which states:

> 121. The greater weight of the evidence supports the conclusion that DEF did not exercise reasonable care in operating the steam turbine in a configuration for which it was not designed and under circumstances which DEF knew, or should have known, that it should have proceeded with caution, seeking the cooperation of Mitsubishi to devise a means to operate the steam turbine above 420 MW.

Specifically, DEF takes exception with the ALJ's conclusion that it did not exercise reasonable care in operating the steam turbine and should have sought the cooperation of Mitsubishi prior to operating the steam turbine above 420 MW. DEF again argues that it is as or more reasonable to conclude that operation within the express parameters given by Mitsubishi was prudent and did not require further consultation with the manufacturer.

Intervenors' Response

As demonstrated in their response to Paragraphs 110-114 above, Intervenors argue that there is more than adequate competent substantial evidence to support the ALJ's ultimate determination that DEF did not exercise reasonable care operating the plant in excess of 420 MW without consulting Mitsubishi first. Intervenors assert that the Commission is not free to reject or modify conclusions of law that are supported by competent substantial evidence and logically flow from that evidence.

> 123. DEF failed to carry its burden to show that the Period 5 blade damage and the required replacement power costs were not consequences of DEF's imprudent operation of the steam turbine in Period 1.

For the reasons stated in its exception to Paragraph 110, DEF argues that it did demonstrate by a preponderance of the evidence that it operated the steam turbine prudently in Period 1. Thus, DEF contends that it is as or more reasonable to conclude that DEF carried its burden of proof that the steam turbine was operated prudently in Period 1.

Intervenors' Response

Intervenors contend that the ALJ's conclusion is supported by competent substantial evidence of record as detailed in Intervenors' responses to DEF's exceptions to Paragraphs 110-114 and 119, and is consistent with applicable law. Therefore, Intervenors argue that we cannot, under these circumstances, reject the ALJ's conclusion of law by reweighing the evidence and substituting new and directly contrary findings that are favorable to DEF.

Ruling

A review of DEF's exception reveals that it is simply re-argument of its position taken in Conclusion of Law No. 110 discussed above. For the reasons stated therein, DEF's Exception to Conclusion of Law 123 is denied because DEF has failed to demonstrate that its conclusion is as or more reasonable that the ALJ's.

DEF Exception to Conclusion of Law 124

DEF takes exception with the ALJ's Conclusion of Law 124, which states:

> 124. The de-rating of the steam turbine that required the purchase of replacement power for the 40 MW loss caused by the installation of the pressure plate was a consequence of DEF's failure to prudently operate the steam turbine during Period 1. Because it was ultimately responsible for the de-rating, DEF should refund replacement costs incurred from the point the steam turbine came back on line in May 2017 until the start of the planned fall 2019 outage that allowed the replacement of the pressure plate with the [redacted] in December 2019. Based on the record evidence, the amount to be refunded due to the de-rating is $5,016,782.

DEF argues that the operation of the steam turbine in Period 1 was proven by DEF by a preponderance of the evidence to be prudent. DEF contends that this fact, coupled with the undisputed evidence that DEF also operated the steam turbine prudently in Periods 2-5, demonstrates that it is as or more reasonable to conclude that the Period 5 blade damage and resulting replacement power costs were not a consequence of DEF's operation of the steam turbine during Period 1.

REDACTED

evidence. The revised Comprehensive Exhibit List (CEL) was admitted into evidence by stipulation as Exhibit No. 114.

A three-volume transcript of the final hearing was filed with the Commission Clerk on February 18, 2020, and was provided to the DOAH Clerk on February 24, 2020. DEF, Commission staff, and OPC, jointly with PCS Phosphate and FIPUG, timely filed confidential proposed recommended orders on March 20, 2020. The ALJ issued his Recommended Order[2] on April 27, 2020. A redacted version of the Recommended Order is found in Attachment A to this Final Order.

C. Overview of the Recommended Order

This case involves the operation of DEF's Bartow Unit 4 combined cycle natural gas plant and whether DEF operated the plant prudently from the time it was brought on line in June 2009 until February 2017. Bartow Unit 4 is comprised of a steam turbine manufactured by Mitsubishi Hitachi Power Systems (Mitsubishi) with a gross output of 420 MW connected to four M501 Type F combustion turbines. The steam turbine is an "after-market" unit which was originally designed for Tenaska Power Equipment, LLC (Tenaska) to be used in a 3x1 configuration with three M501 Type F combustion turbines with a gross output of 420 MW. Prior to purchasing the steam turbine, DEF's predecessor, Progress Energy Florida, LLC contracted with Mitsubishi to [redacted] As required by its contract, [redacted]

The Bartow plant has experienced five outages since it was brought on line in June 2009: March 2012 (planned), August 2014 (planned), April 2016 (planned), October 2016 (forced), and February 2017 (forced).

In March 2012 during a scheduled outage, DEF discovered that the [redacted] in the low pressure section of the steam turbine were damaged. The [redacted] were replaced with [redacted] and the plant was operated until August 2014 when the plant was taken out of service to [redacted] the [redacted]. The plant came back on line in December 2014 and ran until April 2016 when it was taken off line for routine valve work and [redacted] inspection. The plant was placed back in service in May 2016 with a [redacted] and operated until October 2016, when DEF shut the plant down due to excessive vibration and loss of [redacted] material. In December 2016 the plant was put back in service with the [redacted], and was taken out of service in February of 2017 due to a [redacted] projectile that traveled through the low pressure turbine rupture disk diaphragm. DEF brought the plant back on line in April 2017 with a pressure plate installed in the low pressure section of the steam turbine, which effectively decreased the output of the plant from 420 to 380 MW. DEF continued to operate the plant with the pressure plates until September 28, 2019.

[2] "Recommended Order" is defined in Section 120.52(15), F.S., as the official recommendation of the ALJ assigned by DOAH or of any other duly authorized presiding officer, other than the agency head or member thereof.

There are two amounts that are associated with the initial prudence question: 1) replacement power costs for the February 2017 outage in the amount of $11.1 million, and 2) May 2017 through September 2019 unit derating[3] costs in the amount of $5,016,782 million.

Petitioner, DEF, has the burden of proving by a preponderance of the evidence, that it acted prudently in the operation of Bartow Unit 4 up to and restoring the unit to service after the February 2017 forced outage. Additionally, DEF must prove by a preponderance of the evidence that no adjustment to replacement power costs should be made to account for the fact that after March 2017, and the installation of a pressure plate, Bartow Unit 4 could no longer produce its rated nameplate capacity of 420 MW. The standard for determining whether replacement power costs are prudent is "what a reasonable utility manager would have done, in light of the conditions and circumstances that were known, or should [have] been known at the time the decision was made."[4]

In his Recommended Order, the ALJ detailed the relevant facts and legal standards required to determine whether DEF acted prudently in its operation of Bartow Unit 4 from June 2009 until February 2017. In his conclusion, the ALJ recommended that this Commission find that DEF failed to demonstrate that it acted prudently in the operation of its Bartow Unit 4 plant and in restoring the unit to service after the February 2017 forced outage, and that DEF should refund a total of $16,116,782 to its customers.

D. Post-Hearing proceedings before the Commission

On May 12, 2020, DEF submitted exceptions to the Recommended Order. OPC, jointly with PCS Phosphate and FIPUG (collectively, the Intervenors), filed a Response to DEF's Exceptions.

We have Jurisdiction over this matter under Sections 120.57, 366.04, 366.05, and 366.06, F.S. As discussed in more detail below, we deny DEF's Exceptions to the Recommended Order and adopt the Administrative Law Judge's Recommended Order as the Final Order.

II. RULINGS ON EXCEPTIONS

A. Standard of Review of Recommended Order and Exceptions

Section 120.57(1)(l), F.S., establishes the standards an agency must apply in reviewing a Recommended Order following a formal administrative proceeding. The statute provides that the agency may adopt the Recommended Order as the Final Order of the agency or may modify or reject the Recommended Order. An agency may only reject or modify an ALJ's findings of fact if, after a review of the entire record, the agency determines and states with particularity that the

[3] "Derating" is the reduction in MW output due to installing pressure plates in place of the [redacted] in the low pressure section of the steam turbine.
[4] *Southern Alliance for Clean Energy v. Graham*, 113 So. 3d 742, 750 (Fla. 2013).

REDACTED

findings of fact were not based on competent substantial evidence or that the proceedings on which the findings were based did not comply with the essential requirements of law.[5]

Section 120.57(1)(l), F.S., also states that an agency in its final order may reject or modify conclusions of law over which it has substantive jurisdiction and interpretations of administrative rules over which it has substantive jurisdiction. When rejecting or modifying a conclusion of law or interpretation of administrative rule, the agency must state with particularity its reasons for rejecting or modifying the conclusion of law or interpretation of administrative rule and must make a finding that its substituted conclusion of law or interpretation of administrative rule is as or more reasonable than that which was rejected or modified. Rejection or modification of conclusions of law may not form the basis for rejection or modification of findings of fact.[6]

In regard to parties' exceptions to the ALJ's Recommended Order, Section 120.57(1)(k), F.S., provides that the Commission does not have to rule on exceptions that fail to clearly identify the disputed portion of the Recommended Order by specific page numbers or paragraphs or that do not identify the legal basis for the exception, or those that lack appropriate and specific citations to the record.[7] Section 120.57(1)(l), F.S., requires our final order to include an explicit ruling on each exception and sets a high bar for rejecting an ALJ's findings.

B. <u>Rulings on Exceptions to the Recommended Order</u>

<u>DEF Exception to Conclusion of Law 110</u>

DEF takes exception with the ALJ's Conclusion of Law 110, which states:

> 110. DEF failed to demonstrate by a preponderance of the evidence that its actions during Period 1 were prudent. DEF purchased an aftermarket steam turbine from Mitsubishi with the knowledge that it had been manufactured to the specifications of Tenaska with a design point of 420 MW of output. Mr. Swartz's testimony regarding the irrelevance of the 420 MW limitation was unpersuasive in light of the documentation that after the initial blade failure, DEF itself accepted the limitation and worked with Mitsubishi to find a way to increase the output of the turbine to [redacted]

First, as a general criticism, DEF argues that when weighing the facts presented at hearing, although stating the correct legal standard of review what a reasonable utility manager should have done based on what he knew or should have known at the time - the ALJ did not apply that standard but instead evaluated DEF's actions from the perspective of what is currently known. DEF states that this type of "hindsight" and "Monday-morning quarterbacking" prudence analysis has been found to be inappropriate under *Florida Power Corporation v. Public Service Comm. (Florida Power),* 456 So. 2d 451, 452 (Fla. 1984).

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[5] Section 120.57(1)(l), F.S.
[6] *Id.*
[7] Section 120.57(1)(k), F.S.

Second, DEF disagrees with the ALJ's conclusion that the 420 MW design point was a limitation on the steam turbine. DEF argues that the record supports the conclusion that the 420 MW design point is a fall out number based on various combinations of operating parameters provided by Mitsubishi. DEF argues that operating within the [redacted] was prudent given what DEF knew or should have known during Period 1. At that time, DEF contends that there was no reason to believe that increasing the output above 420 MW would damage the unit [redacted] Thus, DEF concludes that the fact that the [redacted] failed in February 2017 does not mean that the plant operator reasonably should have known that would happen in June 2009.

Third, DEF argues that DEF's compliance with lower than 420 MW output after Period 1 and its request to Mitsubishi for modifications to operate the unit at [redacted] do not logically support the conclusion that DEF agreed the unit originally could not be operated above 420 MW. These actions, according to DEF, allowed the unit to continue to be operated to produce the most power possible while research into the cause of the Period 1 outage was conducted. DEF argues that getting the unit back on line producing as much power as possible is implementation of long standing Commission policy that utilities operate generating units for maximum efficiency. DEF asserts that these actions are not evidence of DEF's acceptance of 420 MW as a limitation on the output of the unit.

Intervenors' Response

Intervenors contend that DEF, while conceding that the ALJ referenced the correct legal standard for prudence review, never explains or demonstrates exactly how the ALJ applied "Monday-morning quarterbacking" to reach any of the conclusions in Conclusions of Law 110. In the determination of what a utility knew or should have known at any past point in time, Intervenors state that there is necessarily a review of contemporaneous prior actions and documents. They contend that that review was done here. Intervenors note that DEF has not argued that there is no competent substantial evidence supporting the ALJ's conclusions in Conclusions of Law 110 and cites nine separate parts of the record that do logically support the ALJ's conclusion that DEF did not act prudently in running the unit above 420 MW in Period 1.

Intervenors further argue that the *Florida Power* case relied upon by DEF is not applicable here for several reasons. In *Florida Power*, the Commission classified "non-safety related" repair work as "safety-related" repair work and then applied the higher standard of care for "safety-related" repair work to determine if Florida Power had conducted the repairs prudently. Finding that the record indicated that the extensive repair work was not *per se* safety-related, the Court found that the Commission could not apply the higher standard of care. *Florida Power,* 456 So. 2d at 451. Intervenors argue that in this case, the facts upon which the ALJ relied regarding the repair of the unit are supported by competent substantial evidence and are not in dispute, nor does DEF argue that the inferences drawn from the facts by the ALJ are unreasonable. Intervenors state that DEF would simply draw different conclusions from the same set of facts, i.e., would have us weigh the evidence differently, an action prohibited by Chapter 120, F.S.

were relied upon by the ALJ in reaching his conclusion of imprudence. Without identifying the facts upon which the ALJ improperly relied, it is impossible to evaluate this contention and it is rejected.

The ALJ bases his conclusion that a preponderance of the evidence established the actions of DEF in Period 1 were imprudent on three facts. First, the Mitsubishi aftermarket steam turbine was manufactured with a design point of 420 MW of output. Second, witness Swartz's testimony that the 420 MW was not an operational limitation was unpersuasive. Third, DEF accepted this limitation in Periods 2-5 and [redacted]

With regard to the first point, DEF does not contest that the steam turbine was aftermarket manufactured with a design point of 420 MW. This conclusion is supported by Findings of Fact Nos. 14-26. With regard to the second point, the ALJ extensively discusses the arguments presented by DEF witness Swartz that the 420 MW is not an operational limitation for this steam turbine in Findings of Fact Nos. 16-32 which culminate in Finding of Fact No. 33. Finding of Fact No. 33, a finding that DEF did not contest, states: "The greater weight of the evidence establishes that the Mitsubishi steam turbine was designed to operate at 420 MW of output and that 420 MW was an operational limitation of the turbine." Since DEF did not take exception to the identical statement in Finding of Fact No. 33, DEF has waived its ability to contest Conclusion of Law 110 on the grounds that the design point did not act as an operational limitation. However, even if DEF had taken exception to Finding of Fact 33, it is clear that the ALJ considered and rejected witness Swartz's arguments that DEF did not act imprudently by operating the steam turbine for extended periods of time at more than 420 MW.

With regard to the third point, DEF does not dispute that in Periods 2-5 it complied with the lower operating limitations placed on it by Mitsubishi and worked with Mitsubishi to increase the steam turbine's output to [redacted]. DEF disputes the significance of having done so. DEF argues that by [redacted] in Periods 2-5 it was acting to maximize the steam turbine's output for the benefit of its customers. As a general matter, DEF has argued that if a conclusion of law is "infused with overriding policy considerations," the agency, not the ALJ, should decide that issue.[12] Although not specifically identified, apparently, DEF believes that "maximization of output" is such an "overriding policy consideration" which should be given agency deference when determining operational prudence. However, DEF has not identified any statute, rule or Commission order that identifies "maximization of output" as a Commission policy. Additionally, the idea of agency deference, even in the interpretation of an agency's own rules and statutes, is now highly questionable given the passage of Amendment 6 to the Florida Constitution.[13]

[12] *Pillsbury v. State, Department of Health & Rehabilitative Services,* 744 So. 2d 1040, 1042 (Fla. 2d DCA 1999).

[13] "Section 21. Judicial interpretation of statutes and rules. – In interpreting a state statute or rule, a state court or an officer hearing an administrative action pursuant to general law may not defer to an agency's interpretation of such statute or rule, and must instead interpret such statute or rule de novo."

Additionally, we do not find the *Florida Power* decision cited by DEF on the issue of hindsight to be relevant. In *Florida Power*, the Commission made a finding of fact that was not supported by the record - that "non- safety related" repair work was "safety-related" repair work - and then improperly applied the higher standard of care for "safety-related" repair work. The crux of the problem in *Florida Power* was this unsupported finding of fact. Here DEF is not contesting any of the ALJ's 102 findings of fact as being unsupported by competent substantial evidence. Nor is DEF arguing that the legal conclusions the ALJ has drawn from these uncontested facts are unreasonable. Here there is no mistake of fact triggering the misapplication of a legal standard. In this case all parties agree on the standard to be applied, DEF simply does not like the result reached by the ALJ.

Because DEF has failed to establish that its exception to Conclusion of Law 110 is as or more reasonable that that of the ALJ, DEF's Exception to Conclusion of Law 110 is denied.

DEF Exception to Conclusion of Law 111

DEF takes exception with the ALJ's Conclusion of Law 111, which states:

> 111. DEF's RCA [Root Cause Analysis] concluded that the blade failures were caused [redacted] This conclusion is belied by the fact that [redacted] Mitsubishi cannot be faulted for [redacted] in a way that would allow an operator to run the turbine consistently beyond its capacity.

DEF takes exception to the conclusion that the [redacted] were not caused by [redacted] DEF argues that Mitsubishi was contracted specifically to assess whether this particular steam turbine could handle the proposed 4x1 steam configuration. DEF states that Mitsubishi did not originally identify [redacted] as a potential problem and it was reasonable for DEF in Period 1 to rely upon Mitsubishi's assessment. The better comparison, according to DEF, is not with other Mitsubishi facilities, but with blade failures in Periods 2-5 when the unit was run at less than 420 MW. Finally, DEF notes that the exact time that the [redacted] were damaged in Period 1 cannot be established. DEF states that the damage could have occurred during the half of the time in Period 1 when the steam turbine was operated at less than 420 MW.

Intervenors' Response

Intervenors respond that the conclusions of law in Paragraph 111 are supported by competent substantial evidence of record. Further, to the extent that a finding is both a factual and legal conclusion, Intervenors state that it cannot be rejected when there is competent substantial evidence to support the conclusion and the legal conclusion necessarily follows. *Berger*, 653 So. 2d at 480; *Strickland*, 799 So. 2d at 279; *Dunham*, 652 So. 2d at 897. Additionally, Intervenors contend that it is the ALJ, not the Commission, who is authorized to interpret the evidence presented and to decide between two contrary positions supported by conflicting evidence. *Heifetz v. Dept. of Business Regulation*, 475 So. 2d 1277, 1281-2 (Fla. 1st DCA 1985). With regard to DEF's reliance on the fact that it is impossible to tell when the [redacted] were damaged in Period 1, Intervenors find this to be irrelevant since the ALJ does not address that fact in Paragraph 111.

Ruling

This conclusion of law constitutes the ALJ's rejection of DEF's Root Cause Analysis (RCA) conclusion that the low pressure steam turbine 40" [redacted].[14] [redacted][15] [redacted][16] Given these facts, none of which are disputed by DEF, the ALJ found DEF's exclusion of [redacted] from its final RCA to be troubling, as does this Commission.

The ALJ's Conclusion of Law was adequately supported by the relevant findings of fact. DEF has failed to demonstrate that its conclusion is as or more reasonable than that of the ALJ. For this reason, DEF's Exception to Conclusion of Law 111 is denied.

DEF Exception to Conclusion of Law 112

DEF takes exception with the ALJ's Conclusion of Law 112, which states:

> 112. [redacted]

DEF states that Mitsubishi did not ultimately attribute the [redacted] DEF argues that given the fact that the turbine was not operated above 420 MW in Periods 2 through 5, it is more reasonable to conclude that the damage to the [redacted] in Period 1 was the result of [redacted]

[14] Finding of Fact No. 67.
[15] Finding of Fact No. 83.
[16] Finding of Fact No. 70.

Intervenors' Response

Intervenors contend that DEF does not contest that there are findings of fact supported by competent substantial evidence in the record to support the ALJ's conclusion of law. Thus, Intervenors conclude that, under those circumstances, we cannot reject the ALJ's conclusion of law or substitute its own judgment for that of the ALJ.

Ruling

This conclusion of law constitutes the ALJ's acceptance of Mitsubishi's RCA which concluded [redacted][17] [redacted][18] [redacted].[19]

DEF is simply rearguing its case that its RCA should be substituted for that of Mitsubishi. DEF has not contested the facts upon which Conclusion of Law 112 is based. Conclusion of Law 112 is the companion to Conclusion of Law 111 and it is upheld for the same reasons – that there is competent substantial evidence to support this conclusion and the conclusion is reasonable given the facts proven by a preponderance of the evidence presented. DEF has failed to demonstrate that its conclusion is as or more reasonable than that of the ALJ. Thus, DEF's Exception to Conclusion of Law 112 is denied.

DEF Exception to Conclusion of Law 113

DEF takes exception with the ALJ's Conclusion of Law 113, which states:

> 113. Mr. Polich persuasively argued that it would have been simple prudence for DEF to ask Mitsubishi about the ability of the turbine to operate continuously in excess of 420 MW output before actually operating it at those levels. DEF understood that the blades had been designed for the Tenaska 3x1 configuration and should have at least explored with Mitsubishi the wisdom of operating the steam turbine with steam flows in excess of those anticipated in the original design.

[17] Finding of Fact Nos. 37, 63.
[18] Finding of Fact No. 70.
[19] Finding of Fact No. 78.

DEF defends not contacting Mitsubishi by citing the followin g evidence in the record: 1) [redacted] 2) the MW output of a steam turbine is not an "operating parameter"; and 3) Mitsubishi knew DEF would operate the plant in excess of 420 MW. For these reasons, DEF argues that it is "as or more reasonable" to conclude that DEF did not need to contact Mitsubishi.

Intervenors' Response

Intervenors argue that DEF is simply rehashing the evidence presented and urging this Commission to make new findings that are "as or more reasonable" than the findings made by the ALJ. The ALJ states that he found OPC's expert persuasive on this point and it is the exclusive prerogative of the ALJ, not the Commission, to evaluate the credibility of a witness and the weight to be given to his/her testimony. Intervenors contend that since there is competent substantial evidence supporting the conclusion that DEF should have called Mitsubishi, this conclusion cannot be modified.

Ruling

When viewed as a whole, the ALJ has based his analysis of this case by focusing on several areas. [redacted] Second, the type and meaning of [redacted] Third, the cause of the damage to the low pressure [redacted] Analysis of these three areas results in a finding regarding whether DEF acted prudently in the operation of the steam turbine which in turn drives the decision of whether replacement power costs for the April 2017 outage should be recovered or denied.

The ALJ's findings of fact establish that the steam turbine was originally designed to be used in a 3x1 configuration with a design point maximum of 420 MW. The 3x1 configuration used three M501 Type F combustion turbines connected to the steam turbine.[20] The 4x1 design configuration used by DEF used four M501 Type F combustion turbines connected to the same steam turbine.[21] Section 3.2.1 of the original Purchase Agreement[22] clearly states [redacted].[23] [redacted][24]

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[20] Finding of Fact No. 14.
[21] Finding of Fact No. 6.
[22] Entitled the [redacted] executed between Florida Progress and Mitsubishi.
[23] Finding of Fact No. 26.
[24] Finding of Fact No. 87.

Under these circumstances it is reasonable to believe that Mitsubishi would have [redacted][25] This is especially true since DEF was proposing the use of an additional 501 Type F combustion turbine and heat recovery steam generator, giving DEF's proposed configuration the ability to produce far more steam than needed to generate 420 MW of output when compared to the original 3x1 application for which the steam turbine was designed.[26] Additionally, neither DEF nor Mitsubishi had any experience running a 4x1 combined cycle plant prior to commencing operation of Bartow Unit 4.[27] In sum, for these reasons the ALJ found that Mitsubishi did not contemplate DEF's operation of the steam turbine beyond the [redacted] set out in the Purchase Agreement.[28]

Given these extremely unique circumstances, the ALJ concluded that DEF's failure to contact Mitsubishi before pushing output beyond 420 MW was not prudent. Contacting Mitsubishi would have allowed DEF to receive written verification from Mitsubishi that the steam turbine could be safely operated above 420 MW and would have effectively updated the warranty to reflect the higher MW output.[29] The ALJ's conclusion of law is supported by competent substantial evidence of record. Because DEF has failed to demonstrate that its conclusion of law is as or more reasonable than the ALJ's, DEF's Exception to Conclusion of Law 113 is denied.

DEF Exception to Conclusion of Law 114

DEF takes exception with the ALJ's Conclusion of Law 114, which states:

> 114. The record evidence demonstrated an [redacted] that vibrations associated with high energy loadings were the primary cause of the L-0 blade failures. DEF failed to satisfy its burden of showing its actions in operating the steam turbine in Period 1 did not cause or contribute significantly to the vibrations that repeatedly damaged the L-0 blades. To the contrary, the preponderance of the evidence pointed to DEF's operation of the steam turbine in Period 1 as the most plausible culprit.

DEF argues that it is "as or more reasonable" to conclude from the evidence presented that DEF's actions did not cause or contribute significantly to the [redacted] DEF contends this is true because the [redacted] were damaged in Periods 2-5 when the unit was not run above 420 MW as well as Period 1 when it was. DEF further states that the ALJ is imposing the impossible standard of proving a negative. DEF argues that it does not have the burden to prove that damage did not occur as a result of its actions. Rather, DEF states that it is only required to show that it acted as a reasonable utility manager would have done given the facts known or reasonably knowable at the time without the benefit of hindsight review.

[25] Finding of Fact No. 87.
[26] Finding of Fact No. 31.
[27] Finding of Fact No. 85.
[28] Finding of Fact No. 102.
[29] Factual Finding No. 93.

Intervenors' Response

Intervenors argue that Conclusion of Law 114 summaries the findings of fact that support the ALJ's ultimate determination. Intervenors state that these findings of fact are supported by competent substantial evidence and we may not reject them. With regard to the contention that the ALJ required DEF to prove a negative, Intervenors argue that DEF has the burden of proof to demonstrate that it acted prudently in the operation of Bartow Unit 4 which requires it to establish a *prima facie* case that it did act prudently and to rebut evidence of its imprudence. The Intervenors assert that DEF did neither here and the ALJ's conclusion may not be disturbed.

Ruling

As discussed in the ruling on Conclusions of Law 110-113 above, the ALJ found that a preponderance of the evidence supported the finding that the [redacted] was caused by vibrations/flutter associated with high energy loadings. Further, the ALJ found that the weight of the evidence supported the conclusion that the high energy loading on the blades was the result of [redacted]. DEF does not contest that these findings of fact are supported by competent substantial evidence of record.

We agree with the ALJ that DEF has the burden of proving that it acted prudently in the operation of its steam turbine, i.e., the burden to make a *prima facie* case supported by competent substantial evidence that it acted prudently. The burden of proof also requires DEF to rebut evidence produced that it acted imprudently. Here under the unique circumstances of this case, DEF has failed to prove it acted prudently in light of the information that was available to it at the time as found by the ALJ in Conclusion of Law 110. DEF's exception to Conclusion of Law 114 reargues DEF's factual position and fails to demonstrate that its conclusion is as or more reasonable than the ALJ's. For these reasons, DEF's Exception to Conclusion of Law 114 is denied.

DEF Exception to Conclusion of Law 119

DEF takes exception with the ALJ's Conclusion of Law 119, which states:

> 119. It is speculative to state that the original Period L-0 blades would still be operating today had DEF observed the [redacted] of 420 MW. It is not speculative to state that the events of Periods 2 through 5 were precipitated by DEF's actions during Period 1. It is not possible to state what would have happened from 2012 to 2017 if the excessive loading had not occurred, but it is possible to state that events would not have been the same.

Specifically, DEF disputes the ALJ's conclusion that it is not speculative to state that the events of Periods 2 through 5 were precipitated by DEF's actions during Period 1. DEF argues that there is no causal link between the operation of the unit in Period 1 and the forced outage that occurred in Period 5. DEF contends that the lack of a causal link is proven by the fact that there was no residual damage done to the steam turbine itself in Period 1 and all parties agreed that DEF's operation of the plant subsequent to Period 1 was prudent.

Intervenors' Response

Intervenors state that the conclusions in Paragraph 119 are based on the ALJ's findings of fact in Paragraphs 84 and 89 which are supported by competent substantial evidence and OPC's expert's credible testimony. Intervenors argue that to the extent that this conclusion is an inference from the ALJ's factual findings, the ALJ is permitted to draw reasonable inferences from competent substantial evidence in the record. *Amador v. School Board of Monroe County*, 225 So. 3d 853, 858 (Fla. 3d DCA 2017). Further, Intervenors state that the fact that more than one reasonable inference can be drawn from the same evidence of record is not grounds for setting aside the ALJ's conclusion. *Id.*

Ruling

This conclusion of law is in response to OPC witness Polich's testimony that the low pressure [redacted] would still have been in use but for the operation of the steam turbine in excess of 420 MW.[30] While the ALJ rejected that conclusion as too speculative, he did accept witness Polich's testimony that the damage to the blades was most likely cumulative during Period 1, making it irrelevant exactly when during the operation of the unit in Period 1 the damage occurred.[31] DEF's witness Swartz testified that the damage to the blades could have occurred in Period 1 during the 50% of the time that the steam turbine was operated under 420 MW, i.e., when by Intervenors' standards, the unit was being operated prudently. Where reasonable people can differ about the facts, an agency is bound by the hearing officer's reasonable inferences based on the conflicting inferences arising from the evidence. *Amador v. School Board of Monroe County*, 225 So. 3d 853, 857-8 (Fla. 3d DCA 2017). Additionally, the hearing officer is entitled to rely on the testimony of a single witness even if the testimony contradicts the testimony of a number of other witnesses. *Stinson v. Winn*, 938 So. 2d 554, 555 (Fla. 1st DCA 2006).

DEF's exception to Conclusion of Law 119 reargues DEF's factual position and fails to demonstrate that its conclusion is as or more reasonable than the ALJ's. For these reasons, DEF's Exception to Conclusion of Law 119 is denied.

DEF Exception to Conclusion of Law 120

DEF takes exception with the ALJ's Conclusion of Law 120, which states:

> 120. In his closing argument, counsel for White Springs summarized the equities of the situation very well:

[30] Finding of Fact No. 84.
[31] Finding of Fact No. 89; Footnote 4.

> You can drive a four-cylinder Ford Fiesta like a V8 Ferrari, but it's not quite the same thing. At 4,000 RPMs, in second gear, the Ferrari is already doing 60 and it's just warming up. The Ford Fiesta, however, will be moaning and begging you to slow down and shift gears. And that's kind of what we're talking about here.
>
> It's conceded as fact that the root cause of the Bartow low pressure turbine problems is [redacted] caused repeatedly over time. The answer to the question is was this due to the way [DEF] ran the plant or is it due to a [redacted] Well, the answer is both.
>
> The fact is that [DEF] bought a steam turbine that was already built for a different configuration that was in storage, and then hooked it up to a configuration . . . that it knew could produce much more steam than it needed. It had a generator that could produce more megawatts, so the limiting factor was the steam turbine.
>
> On its own initiative, it decided to push more steam through the steam turbine to get more megawatts until it broke.
>
> * * *
>
> So from our perspective, [DEF] clearly was at fault for pushing excessive steam flow into the turbine in the first place. The repair which has been established . . . may or may not work, but the early operation clearly impeded [DEF's] ability to simply claim that Mitsubishi was entirely at fault. And under those circumstances, it's not appropriate to assign the cost to the consumers.

DEF argues that Conclusion of Law 120 is a slightly edited, verbatim recitation of PCS Phosphate counsel's final argument which the ALJ adopts, characterizing it as summarizing "the equities of the situation very well." DEF takes exception to that portion of the final argument stating that under the circumstances presented in this case, it is not appropriate to assign the cost of the February 2017 forced outage to DEF's customers. DEF argues that it is as or more reasonable to conclude that here, where DEF consistently acted prudently, DEF should not be forced to bear replacement power costs.

<u>Intervenors' Response</u>

As demonstrated in its response to Paragraphs 110-114 above, Intervenors argue that there is more than adequate competent substantial evidence to support the ALJ's ultimate determination that DEF did not act prudently and should bear replacement power costs. Intervenors state that DEF is simply rearguing the case it presented to the ALJ which the ALJ found to be unpersuasive.

Ruling

As noted above, this conclusion of law is an edited version of PCS Phosphate counsel's final argument which the ALJ agrees has summarized the "equities of the situation very well." [redacted] Further, whether the vibration was due to the way the plant was run or [redacted] is that both are true. The ALJ concludes that DEF was at fault for pushing excessive steam flow into the turbine. The ALJ further agrees that by operating the unit above 420 MW, without contacting Mitsubishi, DEF impeded its ability to claim that Mitsubishi was entirely at fault. Under these circumstances, PCS Phosphate's counsel, and the ALJ, conclude that consumers should not bear replacement power costs.

Upon review of this material, it is clear that it is a summary of Conclusions of Law 110-114 above. These conclusions are supported by competent substantial evidence of record. Again, DEF reargues the factual underpinnings of the ALJ's Conclusion of Law without adequately demonstrating that DEF's conclusion is as or more reasonable. Therefore, DEF's Exception to Conclusion of Law 120 is denied.

DEF Exception to Conclusion of Law 121

DEF takes exception with the ALJ's Conclusion of Law 121, which states:

> 121. The greater weight of the evidence supports the conclusion that DEF did not exercise reasonable care in operating the steam turbine in a configuration for which it was not designed and under circumstances which DEF knew, or should have known, that it should have proceeded with caution, seeking the cooperation of Mitsubishi to devise a means to operate the steam turbine above 420 MW.

Specifically, DEF takes exception with the ALJ's conclusion that it did not exercise reasonable care in operating the steam turbine and should have sought the cooperation of Mitsubishi prior to operating the steam turbine above 420 MW. DEF again argues that it is as or more reasonable to conclude that operation within the express parameters given by Mitsubishi was prudent and did not require further consultation with the manufacturer.

Intervenors' Response

As demonstrated in their response to Paragraphs 110-114 above, Intervenors argue that there is more than adequate competent substantial evidence to support the ALJ's ultimate determination that DEF did not exercise reasonable care operating the plant in excess of 420 MW without consulting Mitsubishi first. Intervenors assert that the Commission is not free to reject or modify conclusions of law that are supported by competent substantial evidence and logically flow from that evidence.

> 123. DEF failed to carry its burden to show that the Period 5 blade damage and the required replacement power costs were not consequences of DEF's imprudent operation of the steam turbine in Period 1.

For the reasons stated in its exception to Paragraph 110, DEF argues that it did demonstrate by a preponderance of the evidence that it operated the steam turbine prudently in Period 1. Thus, DEF contends that it is as or more reasonable to conclude that DEF carried its burden of proof that the steam turbine was operated prudently in Period 1.

Intervenors' Response

Intervenors contend that the ALJ's conclusion is supported by competent substantial evidence of record as detailed in Intervenors' responses to DEF's exceptions to Paragraphs 110-114 and 119, and is consistent with applicable law. Therefore, Intervenors argue that we cannot, under these circumstances, reject the ALJ's conclusion of law by reweighing the evidence and substituting new and directly contrary findings that are favorable to DEF.

Ruling

A review of DEF's exception reveals that it is simply re-argument of its position taken in Conclusion of Law No. 110 discussed above. For the reasons stated therein, DEF's Exception to Conclusion of Law 123 is denied because DEF has failed to demonstrate that its conclusion is as or more reasonable that the ALJ's.

DEF Exception to Conclusion of Law 124

DEF takes exception with the ALJ's Conclusion of Law 124, which states:

> 124. The de-rating of the steam turbine that required the purchase of replacement power for the 40 MW loss caused by the installation of the pressure plate was a consequence of DEF's failure to prudently operate the steam turbine during Period 1. Because it was ultimately responsible for the de-rating, DEF should refund replacement costs incurred from the point the steam turbine came back on line in May 2017 until the start of the planned fall 2019 outage that allowed the replacement of the pressure plate with the [redacted] in December 2019. Based on the record evidence, the amount to be refunded due to the de-rating is $5,016,782.

DEF argues that the operation of the steam turbine in Period 1 was proven by DEF by a preponderance of the evidence to be prudent. DEF contends that this fact, coupled with the undisputed evidence that DEF also operated the steam turbine prudently in Periods 2-5, demonstrates that it is as or more reasonable to conclude that the Period 5 blade damage and resulting replacement power costs were not a consequence of DEF's operation of the steam turbine during Period 1.

Exhibit C

DUKE ENERGY FLORIDA
Confidentiality Justification Matrix

DOCUMENT/RESPONSES	PAGE/LINE	JUSTIFICATION
Florida Public Service Commission's Amended Final Order No. PSC-2020-0368A-FOF-EI	**Page 3**: The information after "contracted with Mitsubishi to" and before "As required by its contract" in its entirety The information after "As required by its contract" to the end of the paragraph in its entirety The information after "DEF discovered that the" and before "in the low pressure" in its entirety The information after "were damaged. The" and before "were replaced with" in its entirety The information after "were replaced with" and before "and the plant" in its entirety The information after "out of service to" and before "the" in its entirety The information after "the" and before "The plant came back" in its entirety The information after "routine valve work and" and before "inspection. The plant" in its entirety	§366.093(3)(c), F.S. The document in question contains confidential information, contractual information, or information provided by a third party that DEF is obligated to keep confidential, the disclosure of which would harm its competitive business interests

	The information after "May 2016 with a" and before "and operated until" in its entirety The information after "vibration and loss of" and before "material. In December" in its entirety The information after "service with the" and before "and was taken" in its entirety The information after "due to a" and before "projectile that traveled" in its entirety **<u>Page 4</u>**: The information in the third footnote after "in place of the" and before "in the low pressure" in its entirety **<u>Page 5</u>**: The information at the end of paragraph 110 after "output of the turbine to" in its entirety **<u>Page 6</u>**: The information after "operating within the" and before "was prudent given" in its entirety The information after "damage the unit" and before "Thus, DEF concludes" in its entirety The information after "operate the unit at" and before "do not logically" in its entirety	

	<u>Page 8</u>: The information after "in Periods 2-5 and" to the end of the paragraph in its entirety The information after "turbine's output to" and before "DEF disputes the" in its entirety The information after "DEF argues that by" and before "in Periods 2-5" in its entirety **<u>Page 9</u>**: The information in paragraph 111 after "failures were caused" and before "This conclusion is belied" in its entirety The information after "by the fact that" and before "Mitsubishi cannot be" in its entirety The information after "be faulted for" and before "in a way that" in its entirety The information after "conclusion that the" and before "were not caused by" in its entirety The information after "were not caused by" and before "DEF argues that" in its entirety The information after "not originally identify" and	

	before “as a potential problem” in its entirety The information after “exact time that the” and before “were damaged in” in its entirety **<u>Page 10</u>**: The information after “to tell when the” and before “were damaged in” in its entirety The information after “steam turbine 40"” and before “footnote 14” in its entirety The information after “footnote 14” and before “footnote 15” in its entirety The information after “footnote 15” and before “footnote 16” in its entirety The information after “DEF's exclusion of” and before “from its final” in its entirety The information in paragraph 112 in its entirety The information after “ultimately attribute the” and before “DEF argues that” in its entirety The information after “damage to the” and before “in Period 1” in its entirety The information after “was the result of” to the end of	

	the paragraph in its entirety **<u>Page 11</u>**: The information after "which concluded" and before "footnote 17" in its entirety The information after "footnote 17" and before "footnote 18" in its entirety The information after "footnote 18" and before "footnote 19" in its entirety **<u>Page 12</u>**: The information after "evidence in the record: 1)" and before "2) the MW output" in its entirety The information after "focusing on several areas." and before "Second, the type" in its entirety The information after "and meaning of" and before "Third, the cause" in its entirety The information after "the low pressure" and before "Analysis of these" in its entirety The information after "clearly states" and before "footnote 23" in its entirety The information after "footnote 23" and before "footnote 24" in its entirety The information in footnote	

	22 after “Entitled the” and before “executed between Florida” in its entirety **Page 13:** The information after “Mitsubishi would have” and before “footnote 25” in its entirety The information after “turbine beyond the” and before “set out in the” in its entirety The information after “evidence demonstrated an” and before “that vibrations associated” in its entirety The information after “significantly to the” and before “DEF contends this” in its entirety The information after “true because the” and before “were damaged in” in its entirety **Page 14**: The information after “finding that the” and before “was caused by” in its entirety The information after “was the result of” and before “DEF does not contest” in its entirety The information after “DEF observed the” and before “of 420 MW.” in its entirety	

	Page 15: The information after “low pressure” and before “would still have” in its entirety **Page 16:** The information after “turbine problems is” and before “caused repeatedly over” in its entirety The information after “due to a” and before “Well, the answer” in its entirety **Page 17**: The information after “situation very well."” and before “Further, whether the” in its entirety The information after “plant was run or” and before “is that both” in its entirety **Page 19:** The information in paragraph 124 after “plate with the” and before “in December 2019.” in its entirety	

Exhibit D

AFFIDAVIT OF JEFFREY SWARTZ

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery Clause with generating performance incentive Factor	Docket No. 20200001-EI Filed: November 17, 2020

AFFIDAVIT OF JEFFREY SWARTZ IN SUPPORT OF DUKE ENERGY FLORIDA LLC'S REQUEST FOR CONFIDENTIAL CLASSIFICATION

STATE OF FLORIDA

COUNTY OF CITRUS

BEFORE ME, the undersigned authority duly authorized to administer oaths, personally appeared Jeffrey Swartz, who being first duly sworn, on oath deposes and says that:

1. My name is Jeffrey Swartz. I am over the age of 18 years old and I have been authorized by Duke Energy Florida, LLC (hereinafter "DEF" or the "Company") to give this affidavit in the above-styled proceeding on DEF's behalf and in support of DEF's Request for Confidential Classification (the "Request"). The facts attested to in my affidavit are based upon my personal knowledge.

2. I am the Vice President of Florida Generation. I am responsible for the overall leadership and strategic direction of DEF's power generation fleet. My major duties and responsibilities include strategic and tactical planning to operate and maintain DEF's non-nuclear generation fleet; generation fleet project and additions recommendations; major maintenance programs; outage and project management; retirement of generation facilities; asset allocation; workforce planning and staffing; organizational alignment and design; continuous

business improvements; retention and inclusion; succession planning; and oversight of hundreds of employees and hundreds of millions of dollars in assets and capital and operating budgets.

3. DEF is seeking confidential classification for certain information contained in the Florida Public Service Commission's Amended Final Order PSC-2020-0368A-FOF-EI (DN 11601-2020). The confidential information at issue is contained in confidential Exhibit A to DEF's Request and is outlined in DEF's Justification Matrix that is attached to DEF's Request as Exhibit C. DEF is requesting confidential classification of this information because it contains confidential information, contractual information, or information provided by a third party that DEF is obligated to keep confidential, the disclosure of which would harm its competitive business interests.

4. In order to contract with third-party vendors and Original Equipment Manufacturers on favorable terms, DEF must keep contractual terms and third-party proprietary information confidential, the disclosure of which would be to the detriment of DEF and its customers. DEF takes affirmative steps to prevent the disclosure of this information to the public, as well as limits its dissemination within the Company to those employees with a need to access the information to provide their job responsibilities. Absent such measures, third-party vendors would run the risk that sensitive business information that they provided would be made available to the public and, as a result, end up in possession of potential competitors. Faced with that risk, persons or companies who would otherwise contract with DEF might decide not to do so if DEF did not keep specific information confidential. Without DEF's measures to maintain the confidentiality of sensitive terms in contracts, the Company's efforts to obtain competitive contracts could be undermined.

5. Additionally, the disclosure of confidential information provided by a third party could adversely impact DEF's competitive business interests. If such information was disclosed to DEF's competitors, DEF's efforts to obtain competitive contracts that add economic value to both DEF and its customers could be undermined.

6. Upon receipt of confidential information from third-party vendors, and with its own confidential information, strict procedures are established and followed to maintain the confidentiality of the terms of the documents and information provided, including restricting access to those persons who need the information to assist the Company. At no time since receiving the contracts and information in question has the Company publicly disclosed that information. The Company has treated and continues to treat the information and contracts at issue as confidential.

7. This concludes my affidavit.

Further affiant sayeth not.

Dated the 16th day of November, 2020.

(Signature)
Jeffrey Swartz
Vice President – Generation Florida

THE FOREGOING INSTRUMENT was sworn to and subscribed before me this 16 day of November, 2020 by Jeffrey Swartz. He is personally known to me.

(Signature)
Deanna Lee Carver
(Printed Name)
NOTARY PUBLIC, STATE OF FLORIDA
July 18, 2022
(Commission Expiration Date)

(Serial Number, If Any)

(AFFIX NOTARIAL SEAL)

DEANNA LEE CARVER
Commission # GG 239923
Expires July 18, 2022
Bonded Thru Troy Fain Insurance 800-385-7019

DUKE ENERGY
FLORIDA

Matthew R. Bernier
ASSOCIATE GENERAL COUNSEL

November 17, 2020

VIA OVERNIGHT MAIL

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. 20200001-EI*

Dear Mr. Teitzman:

On November 17, 2020, Duke Energy Florida, LLC ("DEF") electronically filed its Request for Confidential Classification in connection with certain information provided in the Florida Public Service Commission's (FPSC) Amended Final Order No. PSC-2020-0368A-FOF-EI (DN 11601-2020), in the above-referenced matter. As referenced in the Request for Confidential Classification, enclosed with this cover letter is DEF's confidential Exhibit A (in a separate, sealed envelope) that accompanies the above-referenced filing.

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this filing.

Respectfully,

/s/ Matthew R. Bernier

Matthew R. Bernier

MRB/cmw
Enclosures

cc: Parties of Record

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 20200001-EI

Filed: November 17, 2020

DUKE ENERGY FLORIDA, LLC'S
NOTICE OF FILING AND SERVING VERIFIED[1] AFFIDAVITS

Duke Energy Florida, LLC ("DEF"), by and through the undersigned counsel, hereby submits the following attached verified affidavits for the following requests for confidential classification filed by DEF in this proceeding:

1. DEF's Request for Confidential Classification re. Staff's Recommended Order filed August 14, 2020; and
2. DEF's Request for Confidential Classification re. FPSC's Final Order filed October 29, 2020.

This 17th day of November, 2020.

Respectfully submitted,

/s/ Matthew R. Bernier

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FLRegulatoryLegal@duke-energy.com

[1] Due to circumstances with COVID-19, DEF was unable to previously provide verified affidavits for the above-listed filings and discovery responses at the time they were filed and/or served.

CERTIFICATE OF SERVICE

Docket No. 20200001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 17th day of November, 2020.

/s/ Matthew R. Bernier
Attorney

Suzanne Brownless Office of General Counsel FL Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 sbrownle@psc.state.fl.us	J.R. Kelly Office of Public Counsel 111 W. Madison St., Room 812 Tallahassee, FL 32399-1400 kelly.jr@leg.state fl.us
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Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com mqualls@moylelaw.com	Mike Cassel Florida Public Utilities Company 208 Wildlight Avenue Yulee, FL 32097 mcassel@fpuc.com
	Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 20200001-EI

Dated: August 14, 2020

AFFIDAVIT OF JEFFREY SWARTZ IN SUPPORT OF DUKE ENERGY FLORIDA'S <u>REQUEST FOR CONFIDENTIAL CLASSIFICATION</u>

STATE OF FLORIDA

COUNTY OF CITRUS

BEFORE ME, the undersigned authority duly authorized to administer oaths, personally appeared Jeffrey Swartz, who being first duly sworn, on oath deposes and says that:

1. My name is Jeffrey Swartz. I am over the age of 18 years old and I have been authorized by Duke Energy Florida (hereinafter "DEF" or the "Company") to give this affidavit in the above-styled proceeding on DEF's behalf and in support of DEF's Request for Confidential Classification (the "Request"). The facts attested to in my affidavit are based upon my personal knowledge.

2. I am the Vice President of Florida Generation in the Fossil Hydro Operations Department. This section is responsible for overall leadership and strategic direction of DEF's power generation fleet.

3. As the Vice President of Florida Generation, I am responsible, along with the other members of the section, for strategic and tactical planning to operate and maintain DEF's non-nuclear generation fleet, generation fleet project and additions

recommendations, major maintenance programs, outage and project management, and retirement of generation facilities.

4. DEF is seeking confidential classification for information contained in the Staff ("Staff") of the Florida Public Service Commission's ("FPSC") Recommended Order to the Division of Administrative Hearings ("DOAH") held on February 4 and 5, 2020. The confidential information at issue is contained in confidential Exhibit A to DEF's Request and is outlined in DEF's Justification Matrix that is attached to DEF's Request as Exhibit C. DEF is requesting confidential classification of this information because it contains sensitive business information, the disclosure of which would impair the Company's competitive business interests and ability to contract for goods and services on favorable terms.

5. The confidential information at issue relates to proprietary and confidential third-party operating procedures and technical information regarding the third-party's proprietary component design and operation parameters, the disclosure of which would impair third-party's competitive business interests, and if disclosed, the Company's competitive business interests and efforts to contact for goods or services on favorable terms.

6. Further, if DEF cannot demonstrate to its third-party OEM, and others that may enter contracts with DEF in the future, that DEF has the ability to protect those third-parties' confidential and proprietary business information, third-parties will be less likely to provide that information to DEF – harming DEF's ability to prudently operate its business. DEF has not publicly disclosed the information. Without DEF's measures to maintain the confidentiality of this sensitive business information, DEF's ability to

contract with third-parties could detrimentally impact DEF's ability to negotiate favorable contracts, as third-parties may begin to demand a "premium" to do business with DEF to account for the risk that its proprietary information will become a matter of public record, thereby harming DEF's competitive interests and ultimately its customers' financial interests.

7. Upon receipt of its own confidential information, strict procedures are established and followed to maintain the confidentiality of the terms of the documents and information provided, including restricting access to those persons who need the information to assist the Company, and restricting the number of, and access to the information and contracts. At no time since receiving the information in question has the Company publicly disclosed that information. The Company has treated and continues to treat the information at issue as confidential.

8. This concludes my affidavit.

Further affiant sayeth not.

Dated the 16th day of November, 2020.

(Signature)
Jeffrey Swartz
Vice President Florida Generation
Duke Energy Florida, LLC
Florida Regional Headquarters
St. Petersburg, FL

THE FOREGOING INSTRUMENT was sworn to and subscribed before me this 16 day of November, 2020 by Jeffrey Swartz. He is personally known to me.

(Signature)

Deanna Lee Carver
(Printed Name)

(AFFIX NOTARIAL SEAL)

NOTARY PUBLIC, STATE OF FLORIDA

July 18, 2022
(Commission Expiration Date)

(Serial Number, If Any)

DEANNA LEE CARVER
Commission # GG 239923
Expires July 18, 2022
Bonded Thru Troy Fain Insurance 800-385-7019

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery Clause with generating performance incentive Factor	Docket No. 20200001-EI Filed: October 29, 2020

AFFIDAVIT OF JEFFREY SWARTZ IN SUPPORT OF DUKE ENERGY FLORIDA LLC'S <u>REQUEST FOR CONFIDENTIAL CLASSIFICATION</u>

STATE OF FLORIDA

COUNTY OF CITRUS

BEFORE ME, the undersigned authority duly authorized to administer oaths, personally appeared Jeffrey Swartz, who being first duly sworn, on oath deposes and says that:

1. My name is Jeffrey Swartz. I am over the age of 18 years old and I have been authorized by Duke Energy Florida, LLC (hereinafter "DEF" or the "Company") to give this affidavit in the above-styled proceeding on DEF's behalf and in support of DEF's Request for Confidential Classification (the "Request"). The facts attested to in my affidavit are based upon my personal knowledge.

2. I am the Vice President of Florida Generation. I am responsible for the overall leadership and strategic direction of DEF's power generation fleet. My major duties and responsibilities include strategic and tactical planning to operate and maintain DEF's non-nuclear generation fleet; generation fleet project and additions recommendations; major maintenance programs; outage and project management; retirement of generation facilities; asset allocation; workforce planning and staffing; organizational alignment and design; continuous

business improvements; retention and inclusion; succession planning; and oversight of hundreds of employees and hundreds of millions of dollars in assets and capital and operating budgets.

3. DEF is seeking confidential classification for certain information contained in the Florida Public Service Commission's Final Order PSC-2020-0368-FOF-EI (DN 11211-2020). The confidential information at issue is contained in confidential Exhibit A to DEF's Request and is outlined in DEF's Justification Matrix that is attached to DEF's Request as Exhibit C. DEF is requesting confidential classification of this information because it contains confidential information, contractual information, or information provided by a third party that DEF is obligated to keep confidential, the disclosure of which would harm its competitive business interests.

4. In order to contract with third-party vendors and Original Equipment Manufacturers on favorable terms, DEF must keep contractual terms and third-party proprietary information confidential. The disclosure of which would be to the detriment of DEF and its customers. DEF takes affirmative steps to prevent the disclosure of this information to the public, as well as limits its dissemination within the Company to those employees with a need to access the information to provide their job responsibilities. Absent such measures, third-party vendors would run the risk that sensitive business information that they provided would be made available to the public and, as a result, end up in possession of potential competitors. Faced with that risk, persons or companies who would otherwise contract with DEF might decide not to do so if DEF did not keep specific information confidential. Without DEF's measures to maintain the confidentiality of sensitive terms in contracts, the Company's efforts to obtain competitive contracts could be undermined.

5. Additionally, the disclosure of confidential information provided by a third party could adversely impact DEF's competitive business interests. If such information was disclosed to DEF's competitors, DEF's efforts to obtain competitive contracts that add economic value to both DEF and its customers could be undermined.

6. Upon receipt of confidential information from third-party vendors, and with its own confidential information, strict procedures are established and followed to maintain the confidentiality of the terms of the documents and information provided, including restricting access to those persons who need the information to assist the Company. At no time since receiving the contracts and information in question has the Company publicly disclosed that information. The Company has treated and continues to treat the information and contracts at issue as confidential.

7. This concludes my affidavit.

Further affiant sayeth not.

Dated the 16th day of November 2020.

(Signature)
Jeffrey Swartz
Vice President – Generation Florida

THE FOREGOING INSTRUMENT was sworn to and subscribed before me this 16 day of November, 2020 by Jeffrey Swartz. He is personally known to me.

(Signature)
Deanna Lee Carver
(Printed Name)
NOTARY PUBLIC, STATE OF FLORIDA
July 18, 2022
(Commission Expiration Date)

(Serial Number, If Any)

(AFFIX NOTARIAL SEAL)

DEANNA LEE CARVER
Commission # GG 239923
Expires July 18, 2022
Bonded Thru Troy Fain Insurance 800-385-7019

DUKE ENERGY FLORIDA, LLC, Appellants, v. FLORIDA PUBLIC SERVICE COMMISSION, Appellee.	IN THE FLORIDA PUBLIC SERVICE COMMISSION DOCKET NO. 20200001-EI

AMENDED NOTICE OF ADMINISTRATIVE APPEAL

Under Florida Rule of Appellate Procedure 9.030(a)(1)(B)(ii), Duke Energy Florida, LLC, hereby amends its appeal to the Supreme Court of Florida following the issuance of an amended order of the Florida Public Service Commission, Order No. PSC-2020-0368A-FOF-EI, rendered on October 29, 2020. The nature of the order appealed is an amended final order of administrative action by the Florida Public Service Commission. A conformed copy of the Confidential Order is on file with the Commission Clerk and should be maintained in a confidential status during the pendency of this appeal.

Respectfully submitted,

SHUTTS & BOWEN LLP
Attorneys for Duke Energy Florida, LLC
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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 19th day of November 2020, a true and accurate copy of the foregoing was e-filed with the Public Service Commission's online filing system and a true and correct copy has been furnished via electronic mail to the following counsel of record:

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FILED 11/19/2020
DOCUMENT NO. 12533-2020
FPSC - COMMISSION CLERK

DUKE ENERGY FLORIDA, LLC,

Appellants,

v.

FLORIDA PUBLIC SERVICE COMMISSION,

Appellee.

IN THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200001-EI

AMENDED NOTICE OF ADMINISTRATIVE APPEAL

Under Florida Rule of Appellate Procedure 9.030(a)(1)(B)(ii), Duke Energy Florida, LLC, hereby amends its appeal to the Supreme Court of Florida following the issuance of an amended order of the Florida Public Service Commission, Order No. PSC-2020-0368A-FOF-EI, rendered on October 29, 2020. The nature of the order appealed is an amended final order of administrative action by the Florida Public Service Commission. A conformed copy of the Confidential Order is on file with the Commission Clerk and should be maintained in a confidential status during the pendency of this appeal.

Respectfully submitted,

SHUTTS & BOWEN LLP
Attorneys for Duke Energy Florida, LLC
215 South Monroe Street, Suite 804
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Telephone: (850) 241-1717
and
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By: */s Daniel E. Nordby*
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dnordby@shutts.com
Daniel Hernandez (FBN 176834)
dhernandez@shutts.com

I CERTIFY THAT THIS IS A TRUE AND CORRECT COPY OF THE ORIGINAL DOCUMENT THAT WAS FILED WITH THE FLORIDA PUBLIC SERVICE COMMISSION
BY:
ADAM J. TEITZMAN, COMMISSION CLERK
(or Office of Commission Clerk designee)

Alyssa L. Cory (FBN 118150)
acory@shutts.com

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 19th day of November 2020, a true and accurate copy of the foregoing was e-filed with the Public Service Commission's online filing system and a true and correct copy has been furnished via electronic mail to the following counsel of record:

Beth Keating
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FILED 10/29/2020
DOCUMENT NO. 11601-2020
FPSC - COMMISSION CLERK

FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF COMMISSION CLERK

DOCUMENT NUMBER ASSIGNMENT*

FILED DATE: 10/29/2020

DOCKET NO.: 20200001-EI

DOCUMENT NO.: 11601-2020

CONFIDENTIAL

DOCUMENT DESCRIPTION:

(CONFIDENTIAL) Amended Final Order PSC-2020-0368A-FOF-EI establishing fuel cost recovery for Duke Energy.

***This document number has been assigned to a confidential document.**
For further information, contact the Office of Commission Clerk.

E-MAIL: CLERK@PSC.STATE.FL.US PHONE NO. (850) 413-6770 FAX NO. (850) 717-0114

BEFORE THE PUBLIC SERVICE COMMISSION

In Re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 20200001-EI Filed on November 19, 2020

DUKE ENERGY FLORIDA, LLC'S AMENDED
MOTION FOR STAY PENDING JUDICIAL REVIEW

Duke Energy Florida, LLC ("DEF"), pursuant to Rule 25-22.061, Florida Administrative Code, and Rule 9.190(e)(2)(A), Florida Rules of Appellate Procedure, moves to stay the final order of the Commission pending appeal and states:

1. On October 15, 2020, the Commission entered its final order establishing fuel cost recovery for DEF ("Final Order") which denied DEF's filed exceptions and adopted the recommended order issued by the administrative law judge following an evidentiary hearing. *See* Docket No. 20200001-EI, Order No. PSC-2020-0368-FOF-EI. The Final Order concludes DEF (1) failed to act prudently in the operation of its Bartow Power Plant ("Bartow Plant") relating to the February 2017 forced outage, and (2) failed to make prudent adjustment to account for replacement power costs associated with derating of the Bartow Plant and must refund charges to customers in relation to DEF's fuel replacement power and other costs associated with the outages at its Bartow Plant. Specifically, the Final Order determines DEF should refund $16,166,782.00 to its customers.

2. On October 29, 2020, the Commission amended the Final Order ("Amended Final Order"). *See* Docket No. 20200001-EI, Order No. PSC-2020-0368A-FOF-EI. The Amended Final Order remedies a deficiency in the Final Order, which omitted the recommended order of the Administrative Law Judge.

3. Pursuant to Rule 9.030(a)(1)(B)(ii), Florida Rules of Appellate Procedure, DEF timely filed its Notice of Appeal of the Final Order on November 2, 2020. Thereafter, DEF amended its Notice of Appeal to indicate review of the Amended Final Order on November 19, 2020.

4. Rule 25-22.061(1)(a), Florida Administrative Code, provides that when an appealed order involves the refund of money to customers, the Commission **shall** grant a stay pending judicial proceedings upon motion of the utility or company affected. *See In re Aloha Utilities, Inc*, 2005 WL 405335 (Fla. P.S.C. Feb. 7, 2005). While the remaining subsection of Rule 25-22.061 affords the Commission discretion in determining a stay motion, subsection(1)(a) is mandatory when the order appealed "involves the refund of moneys to customers."

5. Because DEF is an investor-owned electric utility and the order on appeal involves the refund of moneys to customers, Rule 25-22.061(1)(a) requires the Commission to grant the requested stay pending appeal.

6. Given the circumstances of this case and the on-going nature of the fuel docket, DEF should not be required to post a bond, corporate undertaking, or any other conditions to secure the revenues collected by DEF that may ultimately be subject to refund if the order under appeal is upheld; that is, because such a refund would take the form of a reduction in DEF's fuel collections for the refund period, no bond, undertaking or other assurances are necessary or appropriate. *See* 25-22.061(1), (3), Florida Administrative Code.

7. DEF meets the prerequisites for a mandatory stay under the plain language of Rule 25-22.061(1)(a). But even if DEF were not entitled to a mandatory stay, the Commission should grant a discretionary stay in the alternative based upon a consideration of the non-

exclusive factors outlined in Rule 25-22.061(2), Florida Administrative Code. Specifically, DEF is likely to prevail on the merits of the appeal and a stay on implementation of the Final Order during the pendency of the appeal would not cause substantial harm or be contrary to the public interest.

8. DEF has demonstrated a likelihood of success on the merits of its appeal for the reasons described in DEF's Proposed Recommended Order at DOAH and in its exceptions to the Recommended Order filed with the Commission, both of which are incorporated by reference herein. If the Amended Final Order is not stayed, and DEF is successful on appeal, DEF would be entitled to recover the improperly refunded revenues from its customers. The public interest favors stability in electric utility rates rather than refunds followed by recoupments. The mandatory stay provided by Rule 25-22.061(1)(a) is consistent with this sound public policy, and the same considerations would counsel in favor of a discretionary stay pending appeal.

9. Pursuant to Rule 28-106.204(3), Florida Administrative Code, the undersigned counsel contacted counsel for each party in this docket to determine whether they object to the requested relief in this motion. DEF is authorized to represent that the Office of Public Counsel opposes the motion and will file a response; that PSC Phosphate and the Florida Industrial Power Users Group oppose the motion, and that Commission Staff, Florida Power & Light, Gulf Power, TECO, and Florida Public Utilities Company take no position on the motion.

CONCLUSION

WHEREFORE, DEF respectfully requests that the Commission enter an order granting a mandatory stay of the Amended Final Order pending appeal. In the alternative, DEF respectfully requests that the Commission enter an order granting a discretionary stay of the Amended Final Order pending appeal.

Respectfully submitted,

SHUTTS & BOWEN LLP
Attorneys for Duke Energy Florida, LLC
215 South Monroe Street, Suite 804
Tallahassee, FL 32301
Telephone: (850) 241-1717

and

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By: */s Daniel E. Nordby*
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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 19th day of November 2020, a true and accurate copy of the foregoing was e-filed with the Public Service Commission's online filing system and a true and correct copy has been furnished via electronic mail to the following counsel of record:

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STATE OF FLORIDA

OFFICE OF COMMISSION CLERK
ADAM J. TEITZMAN
COMMISSION CLERK
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Public Service Commission

November 19, 2020

John A. Tomasino, Clerk
Florida Supreme Court
500 South Duval Street
Tallahassee. Florida, 32399

Re: Fuel and purchased power cost recovery clause with generating performance incentive factor, PSC Docket No. 20200001-EI.

Dear Mr. Tomasino:

Enclosed please find a certified copy of an Amended Notice of Administrative Appeal, which was filed with the Florida Public Service Comission on November 19, 2020, along with its attachment, Order No. PSC-2020-0368A-FOF-EI (Amended Final Order). This Amended Final Order includes information the Florida Public Service Commission has deemed confidential and exempt from public disclosure pursuant to Subsections 366.093(3) and (4), Florida Statutes. This appeal was filed on behalf of the ~~Office of Public Counsel.~~ Duke Energy

AJ 11/20/20

Sincerely,

Adam J. Teitzman
Commission Clerk

AJT:cdr
Enclosure

cc:

Diane Triplett
Matthew Bernier
Daniel Nordy
Daniel Hernandez
Alyssa Cory

Hong Wang
Samantha Cibula
Suzanne Brownless

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: November 20, 2020

TO: Office of Commission Clerk (Teitzman)

FROM: Office of the General Counsel (Brownless) *JSC*
Division of Accounting and Finance (Higgins, Cicchetti) *ALM MC*

RE: Docket No. 20200001-EI – Fuel and purchased power cost recovery clause with generating performance incentive factor.

AGENDA: December 1, 2020 – Regular Agenda – Request for stay pending appellate review-Parties may participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Fay

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On November 8, 2019, due to the extensive confidential nature of the materials involved, two issues in this docket associated with the February 2017 forced outage at Duke Energy Florida, LLC's (DEF) Bartow Unit 4 power plant were referred to the Division of Administrative Hearings. On October 15, 2020, the Commission issued Order No. PSC-2020-0368-FOF-EI[1] establishing fuel cost recovery for DEF which denied DEF's filed exceptions on these issues and adopted the recommended order issued by the administrative law judge following an evidentiary hearing held on February 4-5, 2020. Order No. PSC-2020-0368-FOF-EI finds that DEF failed to demonstrate that it acted prudently in the operation of its Bartow Unit 4 plant and in restoring the unit to service after the February 2017 forced outrage, and that DEF should refund a total of $16,116,782 to its customers.

[1] Order No. PSC-2020-0368-FOF-EI, issued October 15, 2020, in Docket No. 20200001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

On October 29, 2020, Order No. PSC-2020-0368-FOF-EI was amended by Order No. PSC-2020-0368A-FOF-EI,[2] to include Attachment A containing the administrative law judge's recommended order and the parties' proposed recommended orders. In all other regards Order No. PSC-2020-0368A-FOF-EI is identical to Order No. PSC-2020-0368-FOF-EI. On November 2, 2020, DEF filed a Notice of Appeal of Order No. PSC-2020-0368-FOF-EI with the Florida Supreme Court, as well as a Motion for Stay Pending Judicial Review with the Commission.

On November 9, 2020, the Office of Public Counsel (OPC), the Florida Industrial Power Users Group (FIPUG), and White Springs Agricultural Chemicals d/b/a PCS Phosphate (PCS Phosphate), collectively referred to herein as Joint Movants, filed a timely Joint Response to the Motion.[3]

On November 19, 2020, DEF filed an Amended Notice of Appeal of Order No. PSC-2020-0368A-FOF-EI and an Amended Motion for Stay Pending Judicial Review. The Amended Motion for Stay Pending Judicial Review was filed in response to the issuance of amended Order No. PSC-2020-0368A-FOF-EI discussed above. The Motion for Stay Pending Judicial Review and the Amended Motion for Stay Pending Judicial Review are virtually identical and no new arguments are raised in the Amended Motion for Stay Pending Judicial Review that were not presented in the Motion for Stay Pending Judicial Review. For that reason, both the Motion and Amended Motion will be referred to collectively in this recommendation as "Motion."

This recommendation addresses DEF's Motion. The Commission has jurisdiction over this matter pursuant to Sections 366.04, 366.05, and 366.06, Florida Statutes (F.S.).

[2] Order No. PSC-2020-0368A-FOF-EI, issued October 29, 2020, in Docket No. 20200001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*
[3] Arguments regarding whether to grant a stay of Order No. PSC-2020-0368A-FOF-EI have also been presented in the post-hearing briefs filed by the parties on November 10, 2020.

Discussion of Issues

Issue 1: Should Duke Energy Florida, LLC's Motion for Stay Pending Judicial Review be granted?

Recommendation: Yes. DEF has complied with the requirements of Rule 25-22.061(1), F.A.C., and should be granted a stay of the provisions of Order No. PSC-2020-0368A-FOF-EI requiring a refund of $16.1 million associated with the 2017 Bartow Unit 4 outage. As a condition of the stay, DEF should be required to provide adequate security in the form of a corporate undertaking in the amount of the refund plus interest as determined by Rule 25-6.109, F.A.C. (Brownless, Higgins)

Staff Analysis: Rule 25-22.061, F.A.C., states, in relevant part, as follows:

> **25-22.061 Stay Pending Judicial Review**
> (1) When the order being appealed *involves the refund of moneys* to customers or a decrease in rates charged to customers, the Commission *shall,* upon motion filed by the utility or company affected, grant a stay pending judicial proceedings. The *stay shall be conditioned upon* the posting of *good and sufficient bond,* the posting of a *corporate undertaking, or such other conditions as the Commission finds appropriate* to secure the revenues collected by the utility subject to refund.
>
> (2) Except as provided in subsection (1), a party seeking to stay a final or nonfinal order of the Commission pending judicial review may file a motion with the Commission, which has authority to grant, modify, or deny such relief. A stay pending review granted pursuant to this subsection may be conditioned upon the posting of a good and sufficient bond or corporate undertaking, other conditions relevant to the order being stayed, or both. In determining whether to grant a stay, the Commission may, among other things, consider:
> (a) Whether the petitioner has demonstrated a likelihood of success on the merits on appeal;
> (b) Whether the petitioner has demonstrated a likelihood of sustaining irreparable harm if the stay is not granted; and,
> (c) Whether the delay in implementing the order will likely cause substantial harm or be contrary to the public interest if the stay is granted.
>
> . . .

[Emphasis added.]

DEF's Motion for Stay

In its Motion, DEF argues that it is entitled to an automatic stay pursuant to the plain language of Rule 25-22.061(1), Florida Administrative Code (F.A.C.). In support of this position, DEF cites Order No. PSC-05-0144-PCO-WU, issued February 7, 2005, in Docket No. 010503-WU, *In re: Application for increase in water rates for Seven Springs System in Pasco County by Aloha Utilities, Inc. (Aloha).* In *Aloha,* the utility's request for a rate increase was denied and a hearing was held on Proposed Agency Action Order No. PSC-04-0122-PAA-WU[4], which addressed the amount of revenue collected under interim rates to be refunded to customers. By Order No. PSC-04-1050-FOF-WU[5], the Commission ordered a refund to the utility's customers in the amount of $276,066, with interest. Aloha appealed this order and filed a motion for stay pending judicial review under Rule 25-22.061(1)(a), F.A.C., the predecessor to Rule 25-22.061(1), F.A.C.[6] In granting Aloha's motion for stay, DEF argues that the Commission quoted the language of Rule 25-22.061(1)(a), F.A.C., and interpreted it as automatically requiring that the Commission grant a stay when a refund was at issue, as is the case here.

Alternatively, DEF argues that even if it is not entitled to an automatic stay under Rule 25-22.061(1), F.A.C., it meets the criteria to be granted a discretionary stay under the provisions of Rule 25-22.061(2), F.A.C. DEF states that it is likely to prevail on the merits of its appeal for the reasons stated in its Proposed Recommended Order filed with DOAH on March 20, 2020[7], and its Exceptions to the Recommended Order filed with the Commission on May 12, 2020[8]. [Motion at ¶ 7] Further, staying the implementation of the refund, in DEF's opinion, would not cause substantial harm or be contrary to the public interest. [Motion at ¶ 6] Finally, DEF argues that the public interest favors rate stability and if it wins on appeal, it would be entitled to recover the improperly refunded revenue from its customers creating a situation where there would be a refund followed by recoupments. That is a situation, which according to DEF, the automatic stay provision of Rule 25-22.061(1), F.A.C., was designed to prevent. [Motion at ¶ 7]

Joint Movants' Response

In opposition to DEF's Motion, Joint Movants argue that Rule 25-22.061, F.A.C., does not apply to charges approved by the Commission in this docket, a docket that has a "self-correcting true-up mechanism." [Response at p. 1] Joint Movants state that the "over/under account", also referred to as the "true-up balance" or "true-up variance", allows for DEF to record the $11.1 million in Bartow Unit 4 replacement fuel costs for future recovery should its appeal be successful. [Response at p. 2] For that reason, according to Joint Movants, the automatic stay is unnecessary, as this true-up mechanism protects the utility and maintains the *status quo* during the pendency of the appeal. [*Id.*]

Joint Movants further argue that Rule 25-22.061, F.A.C., has never been applied to a case where there was a self-correcting true-up mechanism in place, i.e., never applied to the fuel clause docket. [Response at p. 3] Therefore, in Joint Movant's opinion, DEF's reliance on the *Aloha Utilities* case to support imposition of a mandatory stay is misplaced since that case did not involve any type of self-correcting true-up mechanism. Further, Joint Movants cite *GTE Florida Incorporated v. Clark (GTE),* 668 So. 2d. 971, 972-73 (Fla. 1996), for the proposition that a

[4] Order No. PSC-04-0122-PAA-WU, issued February 5, 2004, in Docket No. 010503-WU, *In re: Application for increase in water rates for Seven Springs System in Pasco County by Aloha Utilities, Inc.*
[5] Order No. PSC-04-1050-FOF-WU, issued October 26, 2004, in Docket No. 010503-WU, *In re: Application for increase in water rates for Seven Springs System in Pasco County by Aloha Utilities, Inc.*
[6] The only difference between Rule 25-22.061(1)(a) and Rule 25-22.061(1), F.A.C., is the letter (a). All of the text is identical in both rules.
[7] DN 01546-2020.
[8] DN 02889-2020.

utility can recover its lawful expenses through the imposition of a surcharge after winning an appeal of a Commission order denying those expenses without having to file for a stay either at the appellate court or the Commission. [Response at p. 4]

Joint Movants also question the mandatory nature of the application of Rule 25-22.061(1), F.A.C., stay provisions to prohibit the return of money to customers if, as DEF argues, the mandatory "shall" language in the rule requiring the posting a bond or corporate undertaking if a stay is granted can be ignored due to the self-correcting nature of the fuel clause. [Response at p. 4] Joint Movants regard this argument by DEF as an admission that Rule 25-22.061, F.A.C., should not be applied to the fuel clause.

With regard to DEF's contention that it is entitled to relief under the discretionary provisions of Rule 25-22.061(2), F.A.C., Joint Movants argue that DEF has not demonstrated that it is likely to prevail on the merits. DEF has simply reiterated the same facts argued before both the administrative law judge and the Commission. [Response at p. 5] Further, OPC states that DEF has not shown that it will suffer any harm if the stay is not granted. Again, OPC argues that no harm would be suffered by DEF due to the self-correcting operation of the fuel clause.

Finally, with regard to the $5 million replacement power costs associated with the installation of pressure plates on the Bartow Unit 4 steam turbine in September 2017, Joint Movants argue that this fuel cost was never explicitly approved as prudent by the Commission. The replacement power costs were never recorded in the "over/under account" and were simply included in 2019 fuel costs and passed along to customers. [Response at p. 3] Now that these costs have been specifically found by the administrative law judge and the Commission to be imprudent, Joint Movants contend that they should not be subject to either an automatic or discretionary stay. [*Id.*]

Analysis and Conclusion

Section 120.52(16), F.S., defines a "rule" as "each agency statement of general applicability that implements, interprets, or prescribes law or policy or describes the procedure or practice requirements of an agency ...." An agency is "obligated to follow its own rules."[9] In applying or interpreting rules, the starting point is the plain language of the rule.[10] Courts will not imply a meaning or limitation that the plain language of the rule does not supply.[11]

Staff agrees with DEF that the plain language of Rule 25-22.061(1), F.A.C., unambiguously states that if the order being appealed requires the utility to make a refund, the Commission *shall*

[9] *Vantage Healthcare Corp. v. Agency for Healthcare Administration,* 687 So. 2d 306, 308 (Fla. 1st DCA 1997); *Collier County Board of County Commissioners v. Fish & Wildlife Commissioners,* 993 So. 2d 69, 72 (Fla. 2d DCA 2008).

[10] *Arbor Health Care Co. v. State of Florida, et al.,*654 So. 2d 1020, 1021 (Fla. 1st DCA 1995); *Legal Environmental Assistance Foundation, Inc. v. Board of County Commissioners of Brevard County,* 642 So. 2d 1081, 1083 (Fla. 1994)(rejecting agency's interpretation of rule that "conflict[ed] with the plain meaning of the regulation."); *Woodley v. Department of Health and Rehabilitative Services,* 505 So. 2d 676, 678 (Fla. 1st DCA 1987)(agency construction of rule that contradicts unambiguous language is erroneous and cannot stand.); *Citizens of State of Florida v. Wilson,* 568 So. 2d 1267, 1271 (Fla. 1990).

[11] *Verizon Florida, Inc. v. Jacobs,* 810 So. 2d 906 (Fla. 2002).

grant a motion for stay pending appeal. Joint Movants do not question that the administrative law judge ordered that DEF *refund* $16,116,782 without interest.[12] Nor are the Joint Movants asking the Commission to interpret a term used in the rule as the Commission has done in previous cases.[13] Joint Movants are asking that the Commission find that the rule does not apply because of the nature of this docket, i.e., that the self-correcting nature of the fuel clause provides the same protection to the utility as a stay. In essence, Joint Movants want the Commission to limit the application of the rule to instances in which no "self-correcting true-up mechanism" is at operation. However, there is no such limitation of application stated in the rule itself. DEF has met the requirements for an automatic stay under the provisions of Rule 25-22.061(1): it has been ordered to refund moneys; it has filed an appeal of the order requiring it to do so; and has filed a motion requesting a stay pending judicial proceedings.

Joint Movants' reliance on the *GTE* decision to justify limitation of the rule is misplaced. The fact that the Commission has the authority to allow surcharges to recoup revenues associated with a successful utility appeal does not extinguish DEF's ability to request and receive a stay under the provisions of Rule 25-22.061(1), F.S. Rule 25-22.061, F.A.C., was enacted in October 1981 and contained identical language in paragraph (1)(a) to that found in paragraph (1) cited above. Had the Commission interpreted the *GTE* decision as rendering the rule to be redundant, it has had ample opportunity over the last 24 years to modify the rule to reflect that understanding. No such modification has been proposed by either the Commission or the Joint Movants to date. Likewise, staff does not find it persuasive that the rule has not been applied to the fuel clause in the past. Utilities have the right to decide on a case by case basis what remedy is the most appropriate for a particular set of circumstances. Failure to request a remedy does not mean that that remedy is not available.

Staff views the Joint Motion's request as a request to modify the provisions of Rule 25-22.061(1), F.A.C. Modification of a rule requires compliance with the provisions of Section 120.54(3), F.S., and Rules 28-103.001-.006, F.A.C., e.g., agency notice of intended action; statement of estimated regulatory costs; a hearing, if requested by a substantially affected party; and filing with the Secretary of State of the adopted rule. The Commission cannot unilaterally rewrite its rules without following these procedures.

Having recommended that DEF has met the requirements for an automatic stay pending appeal, the next question concerns compliance with the second sentence of Rule 25-22.061(1), F.A.C.: "The stay *shall* be conditioned upon the posting of good and sufficient bond, the posting of a corporate undertaking, or such other conditions as the Commission finds appropriate to secure the revenues collected by the utility subject to refund."(Emphasis added.) DEF argues that unlike the first sentence, the last section of the second sentence "provides the Commission with a

[12] Order No. PSC-2020-0368A-FOF-EI at p. 20; Administrative Law Judge's Conclusion of Law No. 125 ("The total amount to be *refunded* to customers as a result of the imprudence of DEF's operation of the steam turbine in Period 1 is $16,116,782, without interest.")(Emphasis added.)

[13] Order No. PSC-03-0896-PCO-TP, issued August 5, 2003, in Docket No. 990649-TP, *In re: Investigation into pricing of unbundled network elements (Sprint/VerizonTrack)*(whether the term "customer" included Competitive Local Exchange Companies (CLECs).

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range of options to secure the revenues necessary to make the refund if upheld on appeal."[14] In this case, DEF argues that the method in which a refund would be implemented in this docket, a reduction in fuel costs in the refund year, makes posting a bond or corporate undertaking unnecessary.[15] Joint Movants take the position that if the mandatory language of the first sentence must be applied to the fuel clause, the mandatory language of the second sentence must be applied as well.

The Commission has historically required either the posting of a bond or corporate undertaking when granting a stay pending appeal whether granted under the automatic provisions of Rule 25-22.061(1) or discretionary provisions of Rule 25-22.062(2), F.A.C. Therefore, staff recommends that DEF be required to provide adequate security in the form of a corporate undertaking as a condition of the stay. The amount to be secured is $16.1 million plus interest as determined by Rule 25-6.109, F.A.C. Duke Energy Corporation, the parent of DEF, and DEF both have Standard & Poor's bond ratings of "A-." In addition, the amount of the potential refund is extremely modest relative to the financial resources available to DEF. Therefore, staff recommends that DEF has sufficient financial capability to support a corporate undertaking of the amount required in this case.

As stated above, staff has recommended that a stay be granted pursuant to the mandatory language used in Rule 25-22.061(1), F.A.C., when refunds are at issue. However, DEF has also alleged that it could also secure a stay under the discretionary provisions of Rule 25-22.061(2), F.A.C. In regard to this assertion, the staff agrees with the Joint Movants that DEF's reliance on the same arguments in its appeal that were previously rejected by both the administrative law judge and the Commission do not support the conclusion that there is a likelihood of success at the appellate level. Nor has DEF demonstrated that it will sustain irreparable harm if the stay in not granted. Based on these facts, the staff would recommend that a stay pursuant to the discretionary provisions of Rule 25-22.061(2), F.A.C., be denied.

Finally, the fact that the Commission did not specifically vote to allow the de-rating replacement power costs associated with the Bartow Unit 4 outage incurred from May 2017 until September 2019 is irrelevant. The testimony of witness Menendez is clear that DEF requested, and has recovered, all fuel and replacement power costs incurred during this time period including those associated with the de-rating of Bartow Unit 4. [T. 345-55] Contrary to the Joint Movant's assertion, the Commission has, in fact, voted to allow the Bartow Unit 4 derating costs in the 2018 and 2019 fuel clause dockets.

For these reasons, staff recommends that the Commission find that DEF has complied with the requirements of Rule 25-22.061(1), F.A.C., and should be granted a stay of the provisions of Order No. PSC-2020-0368A-FOF-EI requiring a refund of $16.1 million associated with the 2017 Bartow Unit 4 outage subject to the posting of a corporate undertaking in the amount of $16.1 million plus interest as determined by Rule 25-6.109, F.A.C.

[14] DEF's Post-Hearing Brief at p. 4-5.
[15] *Id.*

Issue 2: Should this docket be closed?

Recommendation: No. At this time there are outstanding issues for DEF to be voted on in this docket at the Special Agenda Conference set for December 15, 2020, which are contingent upon the Commission's vote on the Motion for Stay Pending Judicial Appeal at issue here. (Brownless)

Staff Analysis: All of DEF's issues identified in the Prehearing Order, Order No. PSC-2020-0415-PHO-EI, are still outstanding and will be voted on at the Special Agenda Conference to be held on December 15, 2020.[16] The Commission's decision whether to grant or deny DEF's Motion will impact its decision on outstanding Issue 1A: "What action should be taken in response to Commission Order No. PSC-2020-0368[A] regarding the Bartow Unit 4 February 2017 outage." However, a vote will still be required at the Special Agenda Conference on Issue 1A as well as the other outstanding issues. Thus, staff recommends that this docket remain open to resolve those issues.

[16] Issues 1A, 6-11, 16-22, 23A-23D, 27-33, 34-36.

DUKE ENERGY
FLORIDA

Matthew R. Bernier
Associate General Counsel
Duke Energy Florida, LLC.

November 25, 2020

VIA ELECTRONIC FILING

Adam 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. 20200001-EI*

Dear Mr. Teitzman:

Please find enclosed for electronic filing on behalf of Duke Energy Florida, LLC ("DEF"), DEF's Third Request for Extension of Confidential Classification concerning certain information contained in the 2018 Hedging Activities Audit, *Audit Control No.* 15-051-2-1, filed in docket no. 20150001-EI and Revised Exhibit D, Affidavit of James McClay (unverified). The original Request included Exhibits A, B, and C.

There are no changes to the original Request's Exhibit A consisting of the confidential unredacted documents, Exhibit B containing two (2) redacted copies of the confidential document, or Exhibit C containing a justification table in support of DEF's original Request. The aforementioned exhibits remain on file with the Clerk.

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
Associate General Counsel
Matt.Bernier@duke-energy.com

MRB/mw
Enclosures

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	Docket No. 20200001-EI Dated: November 25, 2020

DUKE ENERGY FLORIDA LLC'S
<u>THIRD REQUEST FOR EXTENSION OF CONFIDENTIAL CLASSIFICATION</u>

Duke Energy Florida, LLC, ("DEF" or "Company"), pursuant to Section 366.093, Florida Statutes (F.S.), and Rule 25-22.006, Florida Administrative Code (F.A.C.), submits this Request for Extension of Confidential Classification (the "Request") for certain information contained in Staff's audit work papers pertaining to DEF's 2015 Hedging Activities Audit (*Audit Control No. 15-051-2-1*). In support of this Request, DEF states:

1. On October 7, 2015, DEF filed a request for confidential classification for certain information contained in Staff's Audit Work papers pertaining to DEF's 2015 Hedging Activities (Document No. 06298-2015), as it contains sensitive business information such as contractual and competitively negotiated data.

2. DEF's October 7, 2015 Request was granted by Order No. PSC-2015-0583-CFO-EI. On June 16, 2017, DEF filed its First Request for Extension of Confidential Classification. The June 16, 2017 Request was granted by Order No. 2017-0333-CFO-EI. On February 25, 2019, DEF filed its Second Request for Extension of Confidential Classification. The February 25, 2019 was granted by Order No. PSC-2019-0197-CFO-EI. The period of confidential treatment granted by that order will expire on November 30, 2020. The information continues to warrant treatment as "proprietary confidential business information"

within the meaning of Section 366.093(3), F.S. Accordingly, DEF is filing its Second Request for Extension of Confidential Classification.

3. DEF submits that the information contained in the audit work papers identified in Exhibit "A" and Exhibit "C" to the October 7, 2015 Request[1] continues to be "proprietary confidential business information" within the meaning of section 366.093(3), F.S., and continues to require confidential classification. *See* Affidavit of James McClay at ¶¶ 4-6, attached as Revised Exhibit "D". This information is intended to be and is treated as confidential by the Company. The information has not been disclosed to the public. Pursuant to section 366.093(1), F.S., such materials are entitled to confidential treatment and are exempt from the disclosure provisions of the Public Records Act. See Affidavit of James McClay ¶ 7.

4. Nothing has changed since the issuance of Order No. PSC-2017-0333-CFO-EI to render the information stale or public such that continued confidential treatment would be inappropriate. Upon a finding by the Commission that this information continues to be "proprietary confidential business information," it should continue to be treated as such for an additional period of at least 18 months, and should be returned to DEF as soon as the information is no longer necessary for the Commission to conduct its business. *See* §366.093(4), F.S.

WHEREFORE, for the foregoing reasons, DEF respectfully requests that this Request for Confidential Classification be granted.

[1] DEF hereby incorporates Exhibits A, B, and C to the original Request, Document No. 06298-2015 submitted on October 7, 2015 in Docket No. 20150001-EI as if attached hereto.

RESPECTFULLY SUBMITTED this 25th day of November, 2020.

s/Matthew R. Bernier

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Duke Energy Florida
CERTIFICATE OF SERVICE
Docket No. 20200001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via email this 25th day of November, 2020 to all parties of record as indicated below.

*s/Matthew R. Bernier*______
Attorney

Suzanne Brownless Office of General Counsel FL Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 sbrownle@psc.state.fl.us J. Beasley / J. Wahlen / M. Means Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com mmeans@ausley.com Russell A. Badders Gulf Power Company One Energy Place, Bin 100 Pensacola, FL 32520-0100 russell.badders@nexteraenergy.com Kenneth A. Hoffman Florida Power & Light Company 134 W. Jefferson Street Tallahassee, FL 32301-1713 ken hoffman@fpl.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com mqualls@moylelaw.com	J.R. Kelly Office of Public Counsel 111 W. Madison St., Room 812 Tallahassee, FL 32399-1400 kelly.jr@leg.state.fl.us Paula K. Brown Regulatory Affairs Tampa Electric Company P.O. Box 111 Tampa, FL 33601-0111 regdept@tecoenergy.com Maria Moncada / David Lee Florida Power & Light Company 700 Universe Blvd. (LAW/JB) Juno Beach, FL 33408-0420 maria.moncada@fpl.com david.lee@fpl.com James Brew / Laura W. Baker Stone Law Firm 1025 Thomas Jefferson St., N.W. Suite 800 West Washington, DC 20007 jbrew@smxblaw.com lwb@smxblaw.com Mike Cassel Florida Public Utilities Company 208 Wildlight Avenue Yulee, FL 32097 mcassel@fpuc.com Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com

Exhibit A

“CONFIDENTIAL”

(on file)

Exhibit B

REDACTED
(on file)

Exhibit C

DUKE ENERGY FLORIDA
Confidentiality Justification Matrix
(on file)

Revised
Exhibit D

AFFIDAVIT OF JAMES MCCLAY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 20200001-EI

Dated: November 25, 2020

AFFIDAVIT OF JAMES MCCLAY IN SUPPORT OF DUKE ENERGY FLORIDA, LLC'S THIRD REQUEST FOR EXTENSION OF CONFIDENTIAL CLASSIFICATION

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

BEFORE ME, the undersigned authority duly authorized to administer oaths, personally appeared James McClay, who being first duly sworn, on oath deposes and says that:

1. My name is James McClay. I am over the age of 18 years old and I have been authorized by Duke Energy Florida (hereinafter "DEF" or the "Company") to give this affidavit in the above-styled proceeding on DEF's behalf and in support of DEF's Third Request for Extension of Confidential Classification (The "Request"). The facts attested to in my affidavit are based upon my personal knowledge.

2. I am the Director of Natural Gas, Oil and Emissions in the Fuel Procurement Department. This section is responsible for natural gas, fuel oil and emission allowance activity for the Duke Energy Indiana ("DEI"), Duke Energy

Kentucky (“DEK”), Duke Energy Carolinas (“DEC”), Duke Energy Progress (“DEP”), and DEF Systems.

3. As the Director of Natural Gas, Oil and Emissions, I am responsible, along with the other members of the section, for the management of the gas and oil procurement, transportation, hedging activities and administration of gas and oil contracts with various suppliers for DEI’s, DEK’s, DEC’s, DEF’s and DEP’s electrical power generation facilities.

4. DEF is seeking a third extension of confidential classification for certain information contained in Staff’s Hedging Audit Work papers, Audit Control No. 15-051-2-1 (document no. 06298-2015), filed on October 7, 2015 in Docket No. 20150001. There are no changes to the information contained in DEF’s confidential Exhibit A, redacted Exhibit B, and justification matrix C. The referenced Exhibits are on file with the Clerk. DEF is requesting a third extension of confidential classification of this information because it contains proprietary confidential sensitive business information, the disclosure of which would impair the Company’s efforts to contract for goods or services on favorable terms.

5. DEF negotiates with potential fuel suppliers to obtain competitive contracts for fuel options that provide economic value to DEF and its customers. In order to obtain such contracts, however, DEF must be able to assure fuel suppliers that sensitive business information, volumes, and hedging costs, will be kept confidential. With respect to the information at issue in this Request, DEF has kept confidential and has not publicly disclosed confidential contract terms such as volumes, hedging costs, and itemized hedging gains/losses. Absent such measures, suppliers would run the risk

that sensitive business information that they provided in their bids/contracts with DEF would be made available to the public and, as a result, end up in possession of potential competitors. Faced with that risk, persons or companies who otherwise would contract with DEF might decide not to do so if DEF did not keep specific information confidential. Without DEF's measures to maintain the confidentiality of sensitive terms in contracts between DEF and fuel suppliers, the Company's efforts to obtain competitive fuel supply contracts could be undermined.

6. Additionally, the disclosure of confidential information in DEF's fuel supply contracts, could adversely impact DEF's competitive business interests. If such information was disclosed to DEF's competitors, DEF's efforts to obtain competitive fuel supply options that provide economic value to both DEF and its customers could be compromised by DEF's competitors changing their consumption or purchasing behavior within the relevant markets.

7. Upon receipt of confidential information from fuel suppliers, and with its own confidential information, strict procedures are established and followed to maintain the confidentiality of the terms of the documents and information provided, including restricting access to those persons who need the information to assist the Company, and restricting the number of, and access to the information and contracts. At no time since receiving the contracts and information in question has the Company publicly disclosed that information. The Company has treated and continues to treat the information and contracts at issue as confidential.

8. This concludes my affidavit.

Further affiant sayeth not.

Dated the _____ day of ____________, 20___.

____
(Signature)
James McClay
Director of Natural Gas, Oil and Emissions
Duke Energy
526 South Church
Charlotte, NC 28202

THE FOREGOING INSTRUMENT was sworn to and subscribed before me this ___ day of __________, 20____ by James McClay. He is personally known to me or has produced his ____________________ driver's license, or his ______________________ as identification.

____
(Signature)

____
(Printed Name)

(AFFIX NOTARIAL SEAL)

NOTARY PUBLIC, STATE OF _________

____
(Commission Expiration Date)

____
(Serial Number, If Any)

DUKE ENERGY
FLORIDA

Matthew R. Bernier
Associate General Counsel
Duke Energy Florida, LLC.

November 25, 2020

VIA ELECTRONIC FILING

Adam 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. 20200001-EI*

Dear Mr. Teitzman:

Please find enclosed for electronic filing on behalf of Duke Energy Florida, LLC ("DEF"), DEF's Request for Extension of Confidential Classification concerning certain information contained in Exhibit No. CAM-2T to the direct testimony of Christopher A. Menendez and Exhibit No. AG-1 to the direct testimony of Arnold Garcia, filed in docket no. 20190001-EI and Revised Exhibit D, Affidavits of Christopher Menendez (verified) and Arnold Garcia (unverified). The original Request included Exhibits A, B, and C.

There are no changes to the original Request's Exhibit A consisting of the confidential unredacted documents, Exhibit B containing two (2) redacted copies of the confidential document, or Exhibit C containing a justification table in support of DEF's original Request. The aforementioned exhibits remain on file with the Clerk.

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
Associate General Counsel
Matt.Bernier@duke-energy.com

MRB/mw
Enclosures

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	Docket No. 20200001-EI Dated: November 25, 2020

DUKE ENERGY FLORIDA LLC'S
REQUEST FOR EXTENSION OF CONFIDENTIAL CLASSIFICATION

Duke Energy Florida, LLC ("DEF" or "Company"), pursuant to Section 366.093, Florida Statutes (F.S.), and Rule 25-22.006, Florida Administrative Code (F.A.C.), submits this Request for Extension of Confidential Classification for certain information provided in Exhibit No. __ (AG-1), to Mr. Arnold Garcia's testimony, and in Exhibit No. __ (CAM-2T), to the testimony of Christopher A. Menendez, dated March 1, 2019 filed in docket number 20190001-EI. In support of this Request, DEF states:

1. On March 1, 2019, DEF filed a request for confidential classification for certain information contained in Exhibit No. __ (AG-1), to Mr. Garcia's testimony and in Exhibit No. __ (CAM-2T), Calculation of Actual True-Up, Sheet 2 of 3 and Calculation of Actual/Estimated True Up, Sheet 3 of 3, to the direct testimony of Mr. Menendez, which includes confidential business information such as contractual cost data, third-party proprietary information, and competitively negotiated data.

2. DEF's March 1, 2019, Request was granted by Order No. PSC 2019-0194-CFO-EI, on May 30, 2019. The period of confidential treatment granted by that order will expire on October 23, 2019. The information continues to warrant treatment as "proprietary confidential business

information" within the meaning of Section 366.093(3), F.S. Accordingly, DEF is filing its Request for Extension of Confidential Classification.

3. DEF submits that certain information provided in Exhibit No. __(CAM-2T) to the direct testimony of Christopher A. Menendez and Exhibit No. ___(AG-1) to the direct testimony of Arnold Garcia, identified in Exhibit "A" and Exhibit "C" to the March 1, 2019 Request[1] continues to be "proprietary confidential business information" within the meaning of section 366.093(3), F.S. and continues to require confidential classification. *See* Affidavits of Christopher A. Menendez and Arnold Garcia at ¶ 4, attached as Revised Exhibit "D". This information is intended to be and is treated as confidential by the Company. The information has not been disclosed to the public.

4. Nothing has changed since the issuance of Order No. PSC-2019-0194-CFO-EI to render the information stale or public such that continued confidential treatment would not be appropriate. Upon a finding by the Commission that this information continues to be "proprietary confidential business information," it should continue to be treated as such for an additional period of at least 18 months, and should be returned to DEF as soon as the information is no longer necessary for the Commission to conduct its business. See §366.093(4), F.S.

WHEREFORE, for the foregoing reasons, DEF respectfully requests that this Request for Extension of Confidential Classification be granted.

1 DEF hereby incorporates Exhibits A, B, C to the original Request, document number 01337-2019, submitted on March 1, 2019 in Docket No. 201900001 as if attached hereto.

RESPECTFULLY SUBMITTED this 25th day of November, 2020.

*s/Matthew R. Bernier*_____

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FloridaRegulatoryLegal@duke-energy.com

Attorneys for Duke Energy Florida, LLC

Duke Energy Florida, LLC
CERTIFICATE OF SERVICE
Docket No. 20200001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via email this 25th day of November, 2020 to all parties of record as indicated below.

*s/Matthew R. Bernier*______
Attorney

Suzanne Brownless Office of General Counsel FL Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 sbrownle@psc.state.fl.us J. Beasley / J. Wahlen / M. Means Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com mmeans@ausley.com Russell A. Badders Gulf Power Company One Energy Place, Bin 100 Pensacola, FL 32520-0100 russell.badders@nexteraenergy.com Kenneth A. Hoffman Florida Power & Light Company 134 W. Jefferson Street Tallahassee, FL 32301-1713 ken hoffman@fpl.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com mqualls@moylelaw.com	J.R. Kelly Office of Public Counsel 111 W. Madison St., Room 812 Tallahassee, FL 32399-1400 kelly.jr@leg.state.fl.us Paula K. Brown Regulatory Affairs Tampa Electric Company P.O. Box 111 Tampa, FL 33601-0111 regdept@tecoenergy.com Maria Moncada / David Lee Florida Power & Light Company 700 Universe Blvd. (LAW/JB) Juno Beach, FL 33408-0420 maria.moncada@fpl.com david.lee@fpl.com James Brew / Laura W. Baker Stone Law Firm 1025 Thomas Jefferson St., N.W. Suite 800 West Washington, DC 20007 jbrew@smxblaw.com lwb@smxblaw.com Mike Cassel Florida Public Utilities Company 208 Wildlight Avenue Yulee, FL 32097 mcassel@fpuc.com Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com

Exhibit A

“CONFIDENTIAL”

(on file)

Exhibit B

(on file)

Exhibit C

DUKE ENERGY FLORIDA
Confidentiality Justification Matrix
(on file)

Revised Exhibit D

AFFIDAVIT OF ARNOLD GARCIA

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 20200001-EI

Dated: November 25, 2020

AFFIDAVIT OF ARNOLD GARCIA IN SUPPORT OF
DUKE ENERGY FLORIDA'S
REQUEST FOR EXTENSION OF CONFIDENTIAL CLASSIFICATION

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

BEFORE ME, the undersigned authority duly authorized to administer oaths, personally appeared Arnold Garcia, who being first duly sworn, on oath deposes and says that:

1. My name is Arnold Garcia. I am over the age of 18 years old and I have been authorized by Duke Energy Florida (hereinafter "DEF" or the "Company") to give this affidavit in the above-styled proceeding on DEF's behalf and in support of DEF's Request for Extension of Confidential Classification (the "Request"). The facts attested to in my affidavit are based upon my personal knowledge.

2. I am the Director of Insurance. This section is responsible for placing insurance coverage for Duke Energy and its subsidiaries, including DEF.

3. DEF is seeking an extension of confidential classification for Exhibit No. ___(AG-1) to my direct testimony filed on March 1, 2019 in docket 20190001-EI. There are no changes to the information contained in DEF's confidential Exhibit A, redacted

Exhibit B, and Justification Matrix, Exhibit C. The referenced Exhibits are on file with the Clerk. DEF is requesting an extension of confidential classification of this information because it contains sensitive business information, the disclosure of which would impair the Company's competitive business interests.

4. The confidential information at issue the Insurance Policy covering the Bartow CC Plant in 2017 (the "Policy"). Disclosure of the Policy would impair the Company's competitive business interests and efforts to contract for goods or services on favorable terms. DEF has not publicly disclosed the material terms of the Policy. Without DEF's measures to maintain the confidentiality of this sensitive business information, DEF's ability to contract with third parties would be undermined to the detriment of DEF's competitive business interests and ultimately to the detriment of its customers' interests.

5. Upon receipt of its own confidential information, strict procedures are established and followed to maintain the confidentiality of the terms of the documents and information provided, including restricting access to those persons who need the information to assist the Company, and restricting the number of, and access to the information and contracts. At no time since receiving the information in question has the Company publicly disclosed that information. The Company has treated and continues to treat the information at issue as confidential.

6. This concludes my affidavit.

Further affiant sayeth not.

Dated the _____ day of ________, 2020.

____
(Signature)
Arnold Garcia
Director of Insurance
Duke Energy
550 Tryon Street
Charlotte, NC 28202

THE FOREGOING INSTRUMENT was sworn to and subscribed before me this ___ day of _________, 2020, by Arnold Garcia. He is personally known to me or has produced his ____________________ driver's license, or his ______________________ as identification.

____
(Signature)

____
(Printed Name)

(AFFIX NOTARIAL SEAL) NOTARY PUBLIC, STATE OF _________

____
(Commission Expiration Date)

____
(Serial Number, If Any)

Revised
Exhibit D

AFFIDAVIT OF CHRISTOPHER A. MENENDEZ

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor

Docket No. 20200001-EI

Dated: November 25, 2020

AFFIDAVIT OF CHRISTOPHER A. MENENDEZ IN SUPPORT OF DUKE ENERGY FLORIDA'S
<u>REQUEST FOR EXTENSION OF CONFIDENTIAL CLASSIFICATION</u>

STATE OF FLORIDA

COUNTY OF PINELLAS

BEFORE ME, the undersigned authority duly authorized to administer oaths, personally appeared Christopher A. Menendez, who being first duly sworn, on oath deposes and says that:

1. My name is Christopher A. Menendez. I am over the age of 18 years old and I have been authorized by Duke Energy Florida (hereinafter "DEF" or the "Company") to give this affidavit in the above-styled proceeding on DEF's behalf and in support of DEF's Request for Confidential Classification (the "Request"). The facts attested to in my affidavit are based upon my personal knowledge.

2. I am the Rates and Regulatory Strategy Director within the Regulatory Planning Projects department. This department is responsible for regulatory planning and cost recovery for DEF.

3. As the Rates and Regulatory Strategy Director, I am responsible, along with the other members of the section, for the production and review of the regulatory financial reports of DEF and analysis of state, federal and local regulations and their impact on DEF.

4. DEF is seeking an extension of confidential classification for a certain information Exhibit No. __ (CAM-2T); Calculation of Actual True-Up, Sheet 2 of 3 and Calculation of Actual/Estimated True Up, Sheet 3 of 3, to my direct testimony filed on March 1, 2019, in docket number 20190001-EI. There are no changes to the information contained in DEF's confidential Exhibit A, redacted Exhibit B, and Justification Matrix, Exhibit C. The referenced Exhibits are on file with the Clerk. DEF is requesting an extension of confidential classification of this information because it contains competitively sensitive contractual confidential business information of capacity suppliers DEF contracts with.

5. DEF negotiates with potential capacity suppliers to obtain competitive contracts for capacity purchase options that provide economic value and system reliability to DEF and its customers. In order to obtain such contracts, however, DEF must be able to assure capacity suppliers that sensitive business information, such as the contractual terms, will be kept confidential. DEF enters into contracts that require the information will be protected from disclosure. In order to protect this confidential information, it is also necessary to keep additional information that could be used to compute the confidential information at issue if made public; for example, if costs relating to one contract were held confidential, but all other contractual costs and the resulting subtotal were public, the confidential information would become apparent. For

this reason, DEF has held confidential the remaining information on the subject exhibits that could be used to compute to the confidential information in need of protection.

6. Absent such measures, suppliers would run the risk that sensitive business information that they provided in their contracts with DEF would be made available to the public and, as a result, end up in possession of potential competitors. Faced with that risk, persons or companies who otherwise would contract with DEF might decide not to do so if DEF did not keep those terms confidential. Without DEF's measures to maintain the confidentiality of sensitive terms in contracts between DEF and capacity suppliers, the Company's efforts to obtain competitive capacity contracts could be undermined. Additionally, the disclosure of confidential information in DEF's capacity purchases could adversely impact DEF's competitive business interests. If such information was disclosed to DEF's competitors, DEF's efforts to obtain competitive capacity purchase options that provide economic value to both DEF and its customers could be compromised by DEF's competitors changing their consumption or purchasing behavior within the relevant markets.

7. Upon receipt of confidential information from capacity suppliers, and with its own confidential information, strict procedures are established and followed to maintain the confidentiality of the terms of the documents and information provided, including restricting access to those persons who need the information to assist the Company, and restricting the number of, and access to the information and contracts. At no time since receiving the contracts and information in question has the Company publicly disclosed that information or contracts. The Company has treated and continues to treat the information and contracts at issue as confidential.

8. This concludes my affidavit.

Further affiant sayeth not.

Dated the 24th day of Nov., 2020.

(Signature)
Christopher A. Menendez
Rates and Regulatory Strategy Director
Regulatory Planning Projects
Duke Energy Florida, LLC
299 1st Avenue South
St. Petersburg, FL 33701

THE FOREGOING INSTRUMENT was sworn to and subscribed before me this 24th day of November, 2020, by Christopher A. Menendez. He is personally known to me, or has produced his ____________________ driver's license, or his ______________________ as identification.

(Signature)
Christina Wolf
(Printed Name)

(AFFIX NOTARIAL SEAL)

NOTARY PUBLIC, STATE OF FLORIDA
9/27/21
(Commission Expiration Date)

(Serial Number, If Any)

CHRISTINA WOLF
Commission # GG 146409
Expires September 27, 2021
Bonded Thru Budget Notary Services

Matthew R. Bernier
Associate General Counsel
Duke Energy Florida, LLC.

November 25, 2020

VIA ELECTRONIC FILING

Adam 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. 20200001-EI*

Dear Mr. Teitzman:

Please find enclosed for electronic filing on behalf of Duke Energy Florida, LLC ("DEF"), DEF's Request for Extension of Confidential Classification concerning certain information contained in Exhibit No. JM-1T to the direct testimony of James McClay, filed in docket no. 20190001-EI and Revised Exhibit D, Affidavit of James McClay (unverified). The original Request included Exhibits A, B, and C.

There are no changes to the original Request's Exhibit A consisting of the confidential unredacted documents, Exhibit B containing two (2) redacted copies of the confidential document, or Exhibit C containing a justification table in support of DEF's original Request. The aforementioned exhibits remain on file with the Clerk.

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
Associate General Counsel
Matt.Bernier@duke-energy.com

MRB/mw
Enclosures

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	Docket No. 20200001-EI Dated: November 25, 2020

DUKE ENERGY FLORIDA, LLC'S
<u>REQUEST FOR EXTENSION OF CONFIDENTIAL CLASSIFICATION</u>

Duke Energy Florida, LLC, ("DEF" or "Company"), pursuant to Section 366.093, Florida Statutes (F.S.), and Rule 25-22.006, Florida Administrative Code (F.A.C.), submits this Request for Extension of Confidential Classification for certain information provided in the direct testimony of James McClay and Exhibit No. ___ (JM-1T), in docket number 20190001-EI. In support of this Request, DEF states:

1. On April 3, 2019, DEF filed a Request for Confidential Classification for certain information provided in Exhibit No. ___ (JM-1T) and the direct testimony of James McClay (document number 03487-2019), which includes sensitive business information such as hedging percentages, hedging savings/costs and volumes.

2. DEF's April 3, 2019, Request was granted by Order No. PSC-2019-0196-CFO-EI on May 30, 2019. The period of confidential treatment granted by that order will expire on November 30, 2020. The information continues to warrant treatment as "proprietary confidential business information" within the meaning of Section 366.093(3), F.S. Accordingly, DEF is filing its Request for Extension of Confidential Classification.

3. DEF submits that the information provided in the direct testimony of James McClay and Exhibit No. JM-1T identified in Exhibit "A" and Exhibit "C" to the April 3, 2019

Request[1] continues to be "proprietary confidential business information" within the meaning of section 366.093(3), F.S. and continues to require confidential classification. *See* Affidavit of James McClay at ¶ 5 attached as Revised Exhibit "D". This information is intended to be and is treated as confidential by the Company. The information has not been disclosed to the public. Pursuant to section 366.093(1), F.S., such materials are entitled to confidential treatment and are exempt from the disclosure provisions of the Public Records Act. *See* Affidavit of James McClay at ¶¶ 5-7.

4. Nothing has changed since the issuance of Order No. PSC-2019-0196-CFO-EI to render the information stale or public such that continued confidential treatment would not be appropriate. Upon a finding by the Commission that this information continues to be "proprietary confidential business information," it should continue to be treated as such for an additional period of at least 18 months, and should be returned to DEF as soon as the information is no longer necessary for the Commission to conduct its business. See §366.093(4), F.S.

WHEREFORE, for the foregoing reasons, DEF respectfully requests that this Request for Extension of Confidential Classification be granted.

RESPECTFULLY SUBMITTED this 25th day of November, 2020.

s/Matthew R. Bernier

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[1] DEF hereby incorporates Exhibits A, B, and C to the original Request, Document no. 03487-2019 submitted on April 3, 2019 in Docket No. 20190001-EI as if attached hereto.

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FloridaRegulatoryLegal@Duke-Energy.com

Attorneys for Duke Energy Florida, LLC

Duke Energy Florida, LLC
Docket No.: 20200001
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail this 25th day of November, 2020 to all parties of record as indicated below.

s/Matthew R. Bernier
Attorney

Suzanne Brownless Office of General Counsel FL Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 sbrownle@psc.state fl.us J. Beasley / J. Wahlen / M. Means Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com mmeans@ausley.com Russell A. Badders Gulf Power Company One Energy Place, Bin 100 Pensacola, FL 32520-0100 russell.badders@nexteraenergy.com Kenneth A. Hoffman Florida Power & Light Company 134 W. Jefferson Street Tallahassee, FL 32301-1713 ken.hoffman@fpl.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com mqualls@moylelaw.com	J.R. Kelly Office of Public Counsel 111 W. Madison St., Room 812 Tallahassee, FL 32399-1400 kelly.jr@leg.state fl.us Paula K. Brown Regulatory Affairs Tampa Electric Company P.O. Box 111 Tampa, FL 33601-0111 regdept@tecoenergy.com Maria Moncada / David Lee Florida Power & Light Company 700 Universe Blvd. (LAW/JB) Juno Beach, FL 33408-0420 maria moncada@fpl.com david.lee@fpl.com James Brew / Laura W. Baker Stone Law Firm 1025 Thomas Jefferson St., N.W. Suite 800 West Washington, DC 20007 jbrew@smxblaw.com lwb@smxblaw.com Mike Cassel Florida Public Utilities Company 208 Wildlight Avenue Yulee, FL 32097 mcassel@fpuc.com Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com

Exhibit A

"CONFIDENTIAL"

(on file)

Exhibit B

REDACTED

(on file)

Exhibit C

DUKE ENERGY FLORIDA
Confidentiality Justification Matrix
(on file)

Revised
Exhibit D

AFFIDAVIT OF JAMES MCCLAY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 20200001-EI

Dated: November 25, 2020

AFFIDAVIT OF JAMES MCCLAY IN SUPPORT OF
DUKE ENERGY FLORIDA, LLC'S
REQUEST FOR EXTENSION OF CONFIDENTIAL CLASSIFICATION

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

BEFORE ME, the undersigned authority duly authorized to administer oaths, personally appeared James McClay, who being first duly sworn, on oath deposes and says that:

1. My name is James McClay. I am over the age of 18 years old and I have been authorized by Duke Energy Florida (hereinafter "DEF" or the "Company") to give this affidavit in the above-styled proceeding on DEF's behalf and in support of DEF's Request for Extension of Confidential Classification (the "Request"). The facts attested to in my affidavit are based upon my personal knowledge.

2. I am the Director of Natural Gas, Oil and Emissions of the Fuels and Systems Optimization Department. This section is responsible for hourly trading, financial hedging activities, oil procurement and natural gas procurement and scheduling needed to support the gas generation needs for the Duke Energy Indiana ("DEI"), Duke

Energy Kentucky ("DEK"), Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP"), and DEF Systems.

3. As the Director of Natural Gas, Oil and Emissions, I am responsible, along with the other members of the section, for the management of Southeast power trading, Midwest financial activities, oil procurement and natural gas group procurement, scheduling and hedging activities for Duke Energy regulated generation fleet.

4. DEF is seeking an extension of confidential classification for information provided in Exhibit No. ___ (JM-1T) to my direct testimony filed on April 3, 2019 in docket 20190001-EI. There are no changes to the information contained in DEF's confidential Exhibit A, redacted Exhibit B, and Justification Matrix, Exhibit C. The referenced Exhibits are on file with the Clerk. DEF is requesting an extension of confidential classification of this information because it contains sensitive business information, the disclosure of which would impair the Company's efforts to contract for goods or services on favorable terms.

5. The confidential information at issue relates to DEF's actual hedging results, including information from individual hedging transactions, such as the volume of fuel hedged and the savings/costs of each transaction. DEF negotiates with potential fuel suppliers to obtain competitive contracts for fuel options that provide economic value to DEF and its customers. In order to obtain such contracts, however, DEF must be able to assure fuel suppliers that sensitive business information, such as bid evaluations, pricing, and quantities of fuel, will be kept confidential. With respect to the information at issue in this Request, DEF has kept confidential and has not publicly disclosed confidential information pertaining to contracts for natural gas. Absent such measures,

suppliers would run the risk that sensitive business information that they provided in their bids/contracts with DEF would be made available to the public and, as a result, end up in possession of potential competitors. Faced with that risk, persons or companies who otherwise would contract with DEF might decide not to do so if DEF did not keep specific information confidential. Without DEF's measures to maintain the confidentiality of sensitive terms in contracts between DEF and fuel suppliers, the Company's efforts to obtain competitive fuel supply contracts could be undermined.

6. Additionally, the disclosure of confidential information could adversely impact DEF's competitive business interests. If such information was disclosed to DEF's competitors, DEF's efforts to obtain competitive fuel supply options that provide economic value to both DEF and its customers could be compromised by DEF's competitors changing their consumption or purchasing behavior within the relevant markets.

7. Upon receipt of confidential information from fuel suppliers, and with its own confidential information, strict procedures are established and followed to maintain the confidentiality of the terms of the documents and information provided, including restricting access to those persons who need the information to assist the Company, and restricting the number of, and access to the information and contracts. At no time since receiving the contracts and information in question has the Company publicly disclosed that information. The Company has treated and continues to treat the information and contracts at issue as confidential.

8. This concludes my affidavit.

Further affiant sayeth not.

Dated the _____ day of ________, 2020.

____
(Signature)
James McClay
Director, Natural Gas, Oil and Emissions
Fuels Procurement Department
Duke Energy
526 South Church
Charlotte, NC 28202

THE FOREGOING INSTRUMENT was sworn to and subscribed before me this ___ day of ________, 2020 by James McClay. He is personally known to me, or has produced his ____________________ driver's license, or his ______________________ as identification.

____
(Signature)

____
(Printed Name)

(AFFIX NOTARIAL SEAL) NOTARY PUBLIC, STATE OF _________

____
(Commission Expiration Date)

____
(Serial Number, If Any)

DUKE ENERGY
FLORIDA

Matthew R. Bernier
Associate General Counsel
Duke Energy Florida, LLC.

November 25, 2020

VIA ELECTRONIC FILING

Adam 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. 20200001-EI*

Dear Mr. Teitzman:

Please find enclosed for electronic filing on behalf of Duke Energy Florida, LLC ("DEF"), DEF's Request for Extension of Confidential Classification concerning certain information contained in its response to Staff's First Set of Interrogatories (Nos. 1-8), filed in docket no. 20190001-EI and Revised Exhibit D, Affidavit of James McClay (unverified). The original Request included Exhibits A, B, and C.

There are no changes to the original Request's Exhibit A consisting of the confidential unredacted documents, Exhibit B containing two (2) redacted copies of the confidential document, or Exhibit C containing a justification table in support of DEF's original Request. The aforementioned exhibits remain on file with the Clerk.

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
Associate General Counsel
Matt.Bernier@duke-energy.com

MRB/mw
Enclosures

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	Docket No. 20200001-EI Dated: November 25, 2020

DUKE ENERGY FLORIDA LLC'S
REQUEST FOR EXTENSION OF CONFIDENTIAL CLASSIFICATION

Duke Energy Florida, LLC ("DEF" or "Company"), pursuant to Section 366.093, Florida Statutes ("F.S."), and Rule 25-22.006, Florida Administrative Code ("F.A.C."), submits this Request for Extension of Confidential Classification for certain information provided in its response to Staff's First Request for Interrogatories (Nos. 1-8), served in docket no. 20190001-EI. In support of this Request, DEF states:

1. On March 20, 2019, DEF filed its Request for Confidential Classification for information contained in its response to Staff's First Set of Interrogatories, specifically questions 1, 3, 4, 5, and 6 (document number 03243-2019), which contains "proprietary confidential business information" under Section 366.093(3), Florida Statutes.

2. DEF's March 20. 2019 Request was granted by Order No. PSC-2019-CFO-EI, on May 30, 2019. The period of confidential treatment granted by that order will expire on November 30, 2020. The information continues to warrant treatment as "proprietary confidential business information" within the meaning of Section 366.093(3), F.S. Accordingly, DEF is filing its Request for Extension of Confidential Classification.

3. DEF submits that the portions of information provided in its response to Staff's First Set of Interrogatories (1-8), identified in Exhibit A and Exhibit C to the March 20, 2019 Request[1] continues to be "proprietary confidential business information" within the meaning of Section 366.093(3), F.S and continue to require confidential classification. *See* Affidavit of James McClay at ¶ 4, attached as Revised Exhibit "D". This information is intended to be and is treated as confidential by the Company. The information has not been disclosed to the public. Pursuant to section 366.093(1), F.S., such materials are entitled to confidential treatment and are exempt from the disclosure provisions of the Public Records Act. *See* Affidavit of James McClay ¶¶ 5-7.

4. Nothing has changed since the issuance of Order No. PSC-2019-0195-CFO-EI to render the information stale or public such that continued confidential treatment would not be appropriate. Upon a finding by the Commission that this information continues to be "proprietary confidential business information," it should continue to be treated as such for an additional period of at least 18 months and should be returned to DEF as soon as the information is no longer necessary for the Commission to conduct its business. *See* §366.093(4), F.S.

WHEREFORE, for the foregoing reasons, DEF respectfully requests that this Request for Extension of Confidential Classification be granted.

RESPECTFULLY SUBMITTED this 20th day of November, 2020.

s/Matthew R. Bernier

DIANNE M. TRIPLETT
Deputy General Counsel
Duke Energy Florida, LLC.

[1] DEF hereby incorporates Exhibits A , B, and C to the original Request, Document No. 03243-2019, submitted on March 20, 2019 in Docket No. 20190001-EI as if attached hereto.

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Duke Energy Florida, Inc.
Docket No.: 20200001
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail this 25th day of November, 2020 to all parties of record as indicated below.

s/Matthew R. Bernier
Attorney

Suzanne Brownless Office of General Counsel FL Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 sbrownle@psc.state.fl.us J. Beasley / J. Wahlen / M. Means Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com mmeans@ausley.com Russell A. Badders Gulf Power Company One Energy Place, Bin 100 Pensacola, FL 32520-0100 russell.badders@nexteraenergy.com Kenneth A. Hoffman Florida Power & Light Company 134 W. Jefferson Street Tallahassee, FL 32301-1713 ken hoffman@fpl.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com mqualls@moylelaw.com	J.R. Kelly Office of Public Counsel 111 W. Madison St., Room 812 Tallahassee, FL 32399-1400 kelly.jr@leg.state.fl.us Paula K. Brown Regulatory Affairs Tampa Electric Company P.O. Box 111 Tampa, FL 33601-0111 regdept@tecoenergy.com Maria Moncada / David Lee Florida Power & Light Company 700 Universe Blvd. (LAW/JB) Juno Beach, FL 33408-0420 maria.moncada@fpl.com david.lee@fpl.com James Brew / Laura W. Baker Stone Law Firm 1025 Thomas Jefferson St., N.W. Suite 800 West Washington, DC 20007 jbrew@smxblaw.com lwb@smxblaw.com Mike Cassel Florida Public Utilities Company 208 Wildlight Avenue Yulee, FL 32097 mcassel@fpuc.com Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com

Exhibit A

"CONFIDENTIAL"

(on file)

Exhibit B

REDACTED

(on file)

Exhibit C

DUKE ENERGY FLORIDA
Confidentiality Justification Matrix

(on file)

Revised
Exhibit D

AFFIDAVIT OF JAMES MCCLAY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 20200001-EI

Dated: November 25, 2020

AFFIDAVIT OF JAMES MCCLAY IN SUPPORT OF DUKE ENERGY FLORIDA'S
<u>REQUEST FOR EXTENSION OF CONFIDENTIAL CLASSIFICATION</u>

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

BEFORE ME, the undersigned authority duly authorized to administer oaths, personally appeared James McClay, who being first duly sworn, on oath deposes and says that:

1. My name is James McClay. I am over the age of 18 years old and I have been authorized by Duke Energy Florida (hereinafter "DEF" or the "Company") to give this affidavit in the above-styled proceeding on DEF's behalf and in support of DEF's Request for Confidential Classification (the "Request"). The facts attested to in my affidavit are based upon my personal knowledge.

2. I am the Director of Natural Gas, Oil and Emissions of the Fuels and Systems Optimization Department. This group is responsible for the hourly trading, financial hedging activities, oil procurement and natural gas procurement and scheduling needed to support the gas generation needs for the Duke Energy Indiana ("DEI"), Duke

Energy Kentucky ("DEK"), Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP"), and DEF.

3. As the Director of Natural Gas, Oil and Emissions, I am responsible, along with the other members of the section, for the management of the Southeast power trading, Midwest financial activities, oil procurement and natural gas group procurement, scheduling and hedging activities for the Duke Energy regulated generation fleet.

4. DEF is seeking an extension of confidential classification for certain responses to Staff's First Set of Interrogatories (Nos. 1-8), specifically questions 1, 3, 4, 5, and 6, (document number 03243-2019), filed on March 20, 2019. The confidential information at issue is contained in confidential Exhibit A to DEF's Request and is outlined in DEF's Justification Matrix that is attached to DEF's Request as Exhibit C. DEF is requesting confidential classification of this information because it contains sensitive business information, the disclosure of which would impair the Company's efforts to contract for goods or services on favorable terms.

5. DEF negotiates with potential fuel suppliers to obtain competitive contracts for fuel options that provide economic value to DEF and its customers. In order to obtain such contracts, however, DEF must be able to assure fuel suppliers that sensitive business information, such as bid evaluations, pricing, and quantities of fuel, will be kept confidential. With respect to the information at issue in this Request, DEF has kept confidential and has not publicly disclosed confidential information pertaining to the RFP bid evaluations for coal, natural gas, natural gas storage, and light oil. Absent such measures, suppliers would run the risk that sensitive business information that they provided in their bids/contracts with DEF would be made available to the public and, as a

result, end up in possession of potential competitors. Faced with that risk, persons or companies who otherwise would contract with DEF might decide not to do so if DEF did not keep specific information confidential. Without DEF's measures to maintain the confidentiality of sensitive terms in contracts between DEF and fuel suppliers, the Company's efforts to obtain competitive fuel supply contracts could be undermined.

6. Additionally, the disclosure of confidential information in the RFP bid evaluations, could adversely impact DEF's competitive business interests. If such information was disclosed to DEF's competitors, DEF's efforts to obtain competitive fuel supply options that provide economic value to both DEF and its customers could be compromised by DEF's competitors changing their consumption or purchasing behavior within the relevant markets.

7. Upon receipt of confidential information from fuel suppliers, and with its own confidential information, strict procedures are established and followed to maintain the confidentiality of the terms of the documents and information provided, including restricting access to those persons who need the information to assist the Company, and restricting the number of, and access to the information and contracts. At no time since receiving the contracts and information in question has the Company publicly disclosed that information. The Company has treated and continues to treat the information and contracts at issue as confidential.

8. This concludes my affidavit.

Further affiant sayeth not.

Dated the _____ day of __________, 20____.

____
(Signature)
James McClay
Director – Natural Gas, Oil & Emissions
Fuels and System Optimizing Department
Duke Energy
526 South Church
Charlotte, NC 28202

THE FOREGOING INSTRUMENT was sworn to and subscribed before me this ___ day of ___________, 20___ by James McClay. He is personally known to me, or has produced his ____________________ driver's license, or his ______________________ as identification.

____
(Signature)

____
(Printed Name)

(AFFIX NOTARIAL SEAL)

NOTARY PUBLIC, STATE OF _________

____
(Commission Expiration Date)

____
(Serial Number, If Any)

FILED 12/3/2020
DOCUMENT NO. 13071-2020
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: December 3, 2020

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Accounting and Finance (Higgins) ALM
Division of Economics (Draper) JGH
Division of Engineering (Ellis, Wooten) TB
Office of the General Counsel (Brownless) JSC

RE: Docket No. 20200001-EI – Fuel and purchased power cost recovery clause with generating performance incentive factor.

AGENDA: 12/15/20 – Special Agenda – Post-Hearing Decision – Participation is Limited to Commissioners and Staff

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Fay

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

As part of the continuing fuel and purchased power adjustment and generating performance incentive clause proceedings, an administrative hearing was held by the Florida Public Service Commission (Commission) on November 3, 2020. The purpose of this hearing was to review and ultimately determine electric service providers' period-specific fuel and fuel-related service costs, net purchased power costs, incentives associated with the efficient operation of generation facilities, and capacity-related service costs. These service costs are recovered through the fuel and capacity cost recovery factors that are set annually in this docket.

At the November 3, 2020 hearing, all issues for Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, and Tampa Electric Company were resolved by a bench vote approving the proposed stipulations and staff's oral recommendations on non-stipulated issues.[1] None of Duke Energy Florida, LLC's (DEF) issues were resolved at the November 3, 2020 hearing. With regard to DEF's issues, at hearing, witness Menendez testified on behalf of DEF and was cross-examined by the parties. In lieu of closing arguments on DEF's issues, the Office of Public Counsel (OPC), Florida Industrial Power Users Group (FIPUG), and White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (PCS Phosphate), collectively referred to herein as Intervenors, agreed to brief only DEF Issues 1A, 10, 11, 18, 20 and 22 and to treat all other DEF issues, Issues 6-9, 16, 17, 19, 21, 23A-D, 27-36, as Type 2 stipulations.[2] (TR 541-545) DEF, PCS Phosphate, and OPC and FIPUG jointly, filed briefs on Issues 1A, 10, 11, 18, 20, and 22 on November 10, 2020.

This recommendation addresses all of DEF's issues. The Commission is vested with jurisdiction over the subject matter by the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

[1]Order No. PSC-2020-0415-PHO-EI, issued October 30, 2020, in Docket No. 20200001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*, and Order No. PSC-2020-0439-FOF-EI, issued November 16, 2020, Docket No. 20200001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*.

[2]A Type 2 stipulation occurs on an issue when the utility and the staff, or the utility and at least one party adversarial to the utility, agree on the resolution of the issue and the remaining parties (including staff if they do not join in the agreement) do not object to the Commission relying on the agreed language to resolve that issue in a final order.

Discussion of Issues

Issue 1A: What action should be taken in response to Commission Order No. PSC-2020-0368-FOF-EI regarding the Bartow Unit 4 February 2017 outage?

Recommendation: DEF was granted a stay of Commission Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI on December 1, 2020. Thus, staff recommends that no further action be taken until the appellate review process is concluded. (Brownless)

Position of the Parties

DEF: No action should be taken at this time. The Commission should grant DEF's Motion for Stay Pending Judicial Review. Pursuant to Rule 25-22.061(1), F.A.C., upon motion by an affected utility, the Commission shall stay the effectiveness of any ordered refund or decrease in rates pending judicial review of the order.

OPC/FIPUG: DEF should credit the 2021 fuel (along with a reasonable estimate of interest subject to true-up in a subsequent proceeding), to adjust for the prior overcollection of imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.

PCS Phosphate: Based on Order No. PSC-2020-0368-FOF-EI, issued October 15, 2020, the Commission should direct DEF to reduce its proposed cost recovery amounts for January 2021 through December 2021 by $16.1 million, plus interest, to credit the fuel clause recovery for costs relating to the replacement power and de-rating of Bartow Unit 4.

Staff Analysis:

Parties' Arguments

DEF argued in its post-hearing brief that under Rule 25-22.061(1), Florida Administrative Code (F.A.C.), upon filing an appeal of Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI, it is automatically entitled a stay of the order's effectiveness under the plain language of the rule. (DEF BR 6)

OPC and FIPUG (Joint Parties) argued in their joint post-hearing brief that DEF's fuel cost recovery amount for 2021 should reflect an adjustment for the over-collection of approximately $16.1 million plus interest emanating from the 2017 outage of Bartow Unit 4.[3] (Joint Parties BR 4)

PCS Phosphate argued in its post-hearing brief that pursuant to Order No. PSC-2020-0368-FOF-EI, DEF's cost recovery amounts for January 2021 through December 2021 should be reduced by approximately $16.1 million, plus interest, to credit for replacement power and de-rating costs related to the April 2017 outage of Bartow Unit 4. (PCS Phosphate BR 2)

[3]The "Joint Parties" consist of OPC and FIPUG. The Joint Parties filed a single, or joint post-hearing brief.

Analysis

The arguments of all parties presented in their post-hearing briefs are related to DEF's Motion for Stay and Amended Motion for Stay of Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI, filed on October 15 and October 29, 2020, respectively. These orders established fuel cost recovery for DEF which denied DEF's filed exceptions on these issues and adopted the recommended order issued by the administrative law judge following an evidentiary hearing held on February 4-5, 2020. In Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI, the Commission found that DEF failed to demonstrate that it acted prudently in the operation of its Bartow Unit 4 plant and in restoring the unit to service after the February 2017 forced outage, and that DEF should refund a total of $16,116,782 to its customers.

In its Motions for Stay, DEF argued that since it was ordered to pay a refund, the plain language of Rule 25-22.061(1), F.A.C., required that the Commission grant a stay pending appeal. OPC, FIPUG and PCS Phosphate argued that because of the self-correcting nature of the fuel cost recovery clause, Rule 25-22.061(1), F.A.C., should not apply to the fuel clause docket.

On December 1, 2020, the Commission voted to grant DEF's Motion for Stay and Amended Motion for Stay of Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI pending the resolution of DEF's appeal. Therefore, at this time no further action can be taken until the appeal is resolved.

Conclusion

DEF was granted a stay of Commission Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI on December 1, 2020. Thus, staff recommends that no further action be taken until the appellate review process is concluded.

Issue 6: What are the appropriate actual benchmark levels for calendar year 2020 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?

Recommendation: Staff recommends the Commission find the appropriate actual benchmark level of gains on non-separated energy sales eligible for a shareholder incentive in 2020 is $1,602,141. (Higgins)

Position of the Parties

DEF: $1,602,141.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine DEF's 2020 benchmark for gains on non-separated wholesale energy sales eligible for a shareholder incentive. The appropriate benchmark is a three-year rolling average of actual prior gains on non-separated wholesale energy sales. DEF's customers will retain 100 percent of the gain at or below the benchmark level, and 80 percent above the benchmark level, while DEF's shareholders will retain 20 percent of the gain in excess of the prior three-year rolling benchmark. This methodology was approved by the Commission in Order No. PSC-01-2371-FOF-EI.[4] The relevant time period of staff's analysis is calendar years 2017 through 2019.

The record evidence in this proceeding, proffered by DEF witness Menendez, indicates the 2017-2019 benchmark, or three-year rolling average gain on economy sales is $1,602,141. (EXH 2)

Conclusion

Staff recommends the Commission find the appropriate actual benchmark level of gains on non-separated energy sales eligible for a shareholder incentive in 2020 is $1,602,141.

[4]Order No. PSC-01-2371-FOF-EI, issued December 7, 2001, in Docket No. 010283-EI, *In re: Calculation of gains and appropriate regulatory treatment for non-separated wholesale energy sales by investor-owned electric utilities*.

Issue 7: What are the appropriate estimated benchmark levels for calendar year 2021 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?

Recommendation: Staff recommends the Commission find the appropriate estimated benchmark level of gains on economy sales eligible for a shareholder incentive in 2021 is $1,682,538. (Higgins)

Position of the Parties

DEF: $1,682,538.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine DEF's 2021 estimated benchmark for gains on non-separated wholesale energy sales eligible for shareholder incentive. DEF's customers will retain 100 percent of the gain at or below the benchmark level, and 80 percent above the benchmark level, while DEF's shareholders will retain 20 percent of the gain in excess of the prior three-year rolling average. This methodology was approved by the Commission in Order Nos. PSC-00-1744-FOF-EI and PSC-01-2371-FOF-EI.[5]

The record evidence in this proceeding, as proffered by DEF witness Menendez, indicates DEF's 2021 estimated benchmark for gains on non-separated wholesale energy sales eligible for a shareholder incentive is $1,682,538. (EXH 7)

Conclusion

Staff recommends the Commission find the appropriate estimated benchmark level of gains on economy sales eligible for a shareholder incentive in 2021 is $1,682,538.

[5]Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, in Docket No. 991779-EI, *In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities,* and Order No. PSC-01-2371-FOF-EI, issued December 7, 2001, in Docket No. 010283-EI, *In re: Calculation of gains and appropriate regulatory treatment for non-separated wholesale energy sales by investor-owned electric utilities*.

Issue 8: What are the appropriate final fuel adjustment true-up amounts for the period January 2019 through December 2019?

Recommendation: Staff recommends the appropriate final fuel adjustment true-up amount for the period January 2019 through December 2019 is an under-recovery of $21,535,230, which was incorporated in DEF's mid-course fuel factors approved by Order No. PSC-2020-0154-PCO-EI. (Higgins)

Position of the Parties

DEF: $21,535,230 under-recovery, which was collected as part of DEF's Fuel Midcourse approved in Order No. PSC-2020-0154-PSC[*sic*]-EI.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine DEF's final fuel revenue true-up amount for the period January 2019 through December 2019. This final fuel revenue true-up represents the difference between calendar-year 2019 actual fuel cost and period-applicable revenue that was collected to cover such cost. The record evidence in this proceeding indicates the final fuel revenue true-up amount for the period January 2019 through December 2019 is an under-recovery of $21,535,230. (EXH 2) However, on April 2, 2020, DEF filed its *Emergency Petition for a Temporary Mid-Course Correction* (MCC Petition) for the purpose of reducing its then-current fuel cost recovery factors.[6]

Through the MCC Petition, DEF sought authorization to lower its annual level of fuel cost recovery through a fuel factor (rate) reduction occurring the month of May 2020. As part of the MCC Petition, DEF included the 2019 final fuel revenue under-recovery of $21,535,230 in developing its then-proposed mid-course factors, which were ultimately approved by the Commission in Order No. PSC-2020-0154-PCO-EI.[7] Thus, the record evidence in this proceeding, as proffered by DEF witness Menendez, indicates the final fuel adjustment true-up amount for the period January 2019 through December 2019 is an under-recovery of $21,535,230, which for recovery purposes was incorporated in DEF's mid-course fuel factors.[8]

[6]Commission Document No. 01736-2020.
[7]Order No. PSC-2020-0154-PCO-EI, issued May 14, 2020, in Docket No. 20200001-EI*, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*.
[8]*Id*.

Conclusion

Staff recommends the appropriate final fuel adjustment true-up amount for the period January 2019 through December 2019 is an under-recovery of $21,535,230, which was incorporated in DEF's mid-course fuel factors approved by Order No. PSC-2020-0154-PCO-EI.

Issue 9: What are the appropriate fuel adjustment actual/estimated true-up amounts for the period January 2020 through December 2020?

Recommendation: Staff recommends the actual/estimated fuel revenue true-up amount for the period January 2020 through December 2020 is an over-recovery of $160,850,438. (Higgins)

Position of the Parties

DEF: $160,850,438 over-recovery.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine DEF's actual/estimated fuel revenue true-up amount for the period January 2020 through December 2020. The actual/estimated fuel revenue true-up is based on six months (January-June 2020) of actual fuel cost- and revenue-related data, and a re-estimated six months (July-December 2020) of fuel cost- and revenue-related data relative to the intial 12-month projection performed the prior year.

The record evidence in this proceeding indicates the actual/estimated fuel revenue true-up amount for the period January 2020 through December 2020 is an over-recovery of $160,850,438. (EXH 6) However, DEF incorporated a two-month actual/ten-month estimated 2020 fuel revenue net over-recovery of $78,231,785 ($99,767,015 gross projected 2020 over-recovery) in developing its then-proposed mid-course fuel factors that were approved by the Commission in Order No. PSC-2020-0154-PCO-EI.[9] As such, the effective remaining actual/estimated true-up amount to be included in DEF's 2021 fuel cost recovery factors, which is the subject of Issue 10, is an over-recovery of $61,083,424. (EXH 6)

Conclusion

Staff recommends the actual/estimated fuel revenue true-up amount for the period January 2020 through December 2020 is an over-recovery of $160,850,438.

[9]Order No. PSC-2020-0154-PCO-EI.

Issue 10: What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2021 through December 2021?

Recommendation: Staff recommends the appropriate total fuel adjustment true-up amount to be refunded from January 2021 through December 2021 is an over-recovery of $61,083,424. (Higgins)

Position of the Parties

DEF: $61,083,424 over-recovery.

OPC: The OPC believes this is a fallout issue that is subject to the resolution of Issues 1A and 11.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine the net amount of prior and current period over- or under-collected revenue to be accounted for in setting the future period (2021) fuel factor.

As was discussed in Issue 8, the record evidence in this proceeding indicates the final fuel revenue true-up amount for the period January 2019 through December 2019 is an under-recovery of $21,535,230. (EXH 2) Further, as discussed in Issue 9, the actual/estimated or current period fuel revenue true-up amount for the period January 2020 through December 2020 is an over-recovery of $160,850,438. (EXH 6) However, DEF accounted for a two-month actual/ten-month estimated 2020 fuel revenue net over-recovery of $78,231,785 ($99,767,015 gross projected 2020 over-recovery) to develop its then-proposed mid-course fuel factors that were approved by the Commission in Order No. PSC-2020-0154-PCO-EI.[10] As such, the effective remaining actual/estimated true up amount to be included in setting DEF's 2021 fuel cost recovery factors is an over-recovery of $61,083,424. (EXH 6)

Conclusion

Staff recommends the appropriate total fuel adjustment true-up amount to be refunded from January 2021 through December 2021 is an over-recovery of $61,083,424.

[10]Order No. PSC-2020-0154-PCO-EI.

Issue 11: What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2021 through December 2021?

Recommendation: Staff recommends the total projected fuel and purchased power costs for the period of January 2021 through December 2021 is $1,279,043,741. (Higgins)

Position of the Parties

DEF: $1,279,043,741, which is adjusted for line losses and excludes prior period true-up amounts, revenue taxes and GPIF amounts.

OPC/FIPUG: The fuel cost recovery factors for 2021 should reflect an adjustment for the overcollection of $16.1 million (along with a reasonable estimate of interest (subject to true-up in a subsequent proceeding)) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.

PCS Phosphate: Pursuant to Order No. PSC-2020-0368-FOF-EI, DEF's cost recovery amounts for January 2021 through December 2021 should be reduced by $16.1 million, plus interest, to credit the fuel clause recovery for costs relating to the replacement power and de-rating of Bartow Unit 4.

Staff Analysis:

Parties' Arguments

DEF believes the appropriate projected total fuel and purchased power cost recovery amount for 2021 is $1,279,043,741. (DEF BR 6)

The Joint Parties argued in their post-hearing brief that DEF's fuel cost recovery factor for 2021 should reflect an adjustment for the over-collection of approximately $16.1 million plus interest resulting from the 2017 outage of Bartow Unit 4. (Joint Parties BR 4)

PCS Phosphate argued in its post-hearing brief that it believes pursuant to Order No. PSC-2020-0368-FOF-EI, that DEF's cost recovery amounts for January 2021 through December 2021 should be reduced by approximately $16.1 million, plus interest, to credit for replacement power and de-rating costs related to the April 2017 outage of Bartow Unit 4. (PCS Phosphate BR 2)

Analysis

The purpose of this issue is to determine the total projected jurisdictional fuel and purchased power costs for the period of January 2021 through December 2021. The total projected jurisdictional 2021 fuel and purchased power costs consist of fuel costs for self-generation and purchased power, as well as credits for economy, stratified, and wholesale energy sales. An adjustment to account for jurisdictional line losses is also incorporated. Staff notes the net 2021 fuel cost (i.e. after incorporating the true up, taxes, and other adjustments) is addressed in Issue 18.

Concerning the arguments brought forth by the Joint Parties and PCS Phosphate in regards to Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI, the Commission issued a stay of these orders during the December 1, 2020 Commission Conference. Thus, there are currently no additional or new matters to discuss pending the completion of DEF's appeal of Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI.

The record evidence in this proceeding, as proffered by DEF witness Menendez, indicates the total projected fuel and purchased power costs for the period of January 2021 through December 2021 is $1,279,043,741. (EXH 7)

Conclusion

Staff recommends the total projected fuel and purchased power costs for the period of January 2021 through December 2021 is $1,279,043,741.

Issue 16: What is the appropriate GPIF reward or penalty for performance achieved during the period January 2019 through December 2019 for each investor-owned electric utility subject to the GPIF?

Recommendation: Staff recommends the appropriate GPIF reward applicable to DEF for the period January 2019 through December 2019 is $4,407,712. (Higgins, Ellis, Wooten)

Position of the Parties

DEF: A reward of $4,407,712.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine the appropriate generating performance incentive factor (GPIF) reward or penalty for actual generating unit availability and heat rate efficiency during the period January 2019 through December 2019.

The purpose of the GPIF program is to encourage generating utilities to maximize the heat rate efficiency of their production units. A generating utility will either achieve a reward, or incur a penalty, based on actual plant operational performance relative to specific efficiency targets that are set annually in this proceeding (Issue 17).

The 2019 GPIF efficiency targets currently applicable to DEF were specified by the Commission in Order No. PSC-2018-0610-FOF-EI.[11] The record evidence in this proceeding, as proffered by DEF witness Lewter, indicates that the appropriate GPIF reward applicable to DEF for the period January 2019 through December 2019 is $4,407,712. (EXH 8)

Conclusion

Staff recommends the appropriate GPIF reward appllicable to DEF for the period January 2019 through December 2019 is $4,407,712.

[11]Order No. PSC-2018-0610-FOF-EI, issued December 26, 2018, Docket No. 20180001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*.

Issue 17: What should the GPIF targets/ranges be for the period January 2021 through December 2021 for each investor-owned electric utility subject to the GPIF?

Recommendation: Staff recommends the appropriate GPIF targets and ranges applicable to DEF for the period January 2021 through December 2021 are as listed in Table 17-1. (Higgins, Ellis, Wooten)

Position of the Parties

DEF: The appropriate targets and ranges are shown on Page 4 of Exhibit MIL-1P filed on September 3, 2020 with the Direct Testimony of Mary Ingle Lewter.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine the appropriate GPIF targets and ranges for generating unit availability and heat rate efficiency performance during the future period of January 2021 through December 2021. The purpose of the GPIF program is to encourage generating utilities to maximize the heat rate efficiency of their production units. A generating utility will either achieve a reward, or incur a penalty, based on actual plant operational performance relative to specific efficiency targets that are set annually in this proceeding and issue.

The record evidence in this proceeding, as proffered by DEF witness Lewter, indicates that the GPIF targets and ranges applicable to DEF for the period January 2021 through December 2021 are listed below in Table 17-1:

Table 17-1
GPIF Targets/Ranges for the period January-December, 2021

Plant/Unit		Equivalent Availability Factor			Average Net Operating Heat Rate		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (000)	ANOHR Btu/kWh	ANOHR Btu/kWh	Savings (000)
DEF	Bartow 4	91.05	93.10	$523	7,705	7,950	$4,418
	Crystal River 4	86.11	92.55	2,187	10,299	10,885	5,836
	Crystal River 5	81.01	86.28	1,626	10,434	11,058	5,056
	Hines 1	84.13	85.91	193	7,470	7,599	621
	Hines 2	94.71	95.40	41	7,402	7,599	1,173
	Hines 3	73.66	74.45	201	7,174	7,373	1,210
	Hines 4	93.68	94.85	317	6,999	7,173	1,625
	Total*			$5,087			$19,938

Source: (EXH 9)
*May not compute exactly due to rounding.

Conclusion

Staff recommends the appropriate GPIF targets and ranges applicable to DEF for the period January 2021 through December 2021 are as listed in Table 17-1.

Issue 18: What are the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2021 through December 2021?

Recommendation: Staff recommends the appropriate projected net fuel and purchased power costs and GPIF amount to be included in setting the recovery factor for the period January 2021 through December 2021 is $1,223,244,961. (Higgins)

Position of the Parties

DEF: $1,223,244,961.

OPC/FIPUG: The net fuel and purchased power cost recovery and Generating Performance Incentive amounts included in the recovery factor for 2021 should reflect an adjustment for the overcollection of $16.1 million (along with a reasonable estimate of interest (subject to true-up in a subsequent proceeding)) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.

PCS Phosphate: Agree with OPC.

Staff Analysis:

Parties' Arguments

DEF believes the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amount to be included in developing the recovery factor for 2021 is $1,223,244,961. (DEF BR 6)

The Joint Parties argued in their post-hearing brief that the total net fuel and purchased power cost recovery and Generating Performance Incentive amount included in the recovery factor for 2021 should reflect an adjustment for the over-collection of $16.1 million with interest emanating from the 2017 outage at Bartow Unit 4.[12] (Joint Parties BR 5)

PCS Phosphate concurs with the position of the OPC, or by extension, the Joint Parties. (PCS Phosphate BR 2)

Analysis

The purpose of this issue is to identify the appropriate net amount of fuel and purchased power costs to be included in developing the recovery factor for the period of January 2021 through December 2021. This issue is essentially a "fall-out" issue, where the dollar values of prior or forthcoming decisions are tabulated and summed to arrive at the recommended amount to recover. The relevant components required to calculate the projected 2021 recovery amount are: total jurisdictional fuel and purchase power cost (adjusted for line losses), total true-up, revenue tax, and the GPIF amount. The derivation of DEF's 2021 fuel cost recovery amount is shown in Table 18-1 below:

Table 18-1
DEF 2021 Fuel Cost Recovery

Factor Component	Amount
Jurisdictional Fuel and P.P. Cost (Issue 11)	$1,279,043,741
Total True-up (Issues 8, 9, and 10)	(61,083,424)
Revenue Tax (Issue 19)	876,931
GPIF (Issue 16)	4,407,712
Total*	$1,223,244,961

Sources: (EXH 2, EXH 6, EXH 7, EXH 8)
*May not compute exactly due to rounding.

Concerning the arguments brought forth by the Joint Parties and PCS Phosphate in regards to Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI, the Commission issued a stay of these orders during the December 1, 2020 Commission Conference. Thus, there are currently no additional or new matters to discuss pending the completion of DEF's appeal of Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI.

The record evidence in this proceeding, consistent with staff's recommendations on Issues: 8, 9, 10, 11, 16, and 19 indicates the appropriate projected net fuel and purchased power cost recovery amount, including the GPIF reward, to be included in the fuel cost recovery factor for the period January 2021 through December 2021 is $1,223,244,961.

Conclusion

Staff recommends the appropriate total projected net fuel and purchased power costs and GPIF amount to be included in setting the recovery factor for the period January 2021 through December 2021 is $1,223,244,961.

Issue 19: What is the appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2021 through December 2021?

Recommendation: Staff recommends that the appropriate revenue tax factor to be applied in calculating DEF's levelized fuel factor for the period of January 2021 through December 2021 is 1.00072. (Higgins, Brownless)

Position of the Parties

DEF: 1.00072.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to verify that the appropriate tax factor was applied to the correct/applicable amount of revenue to be collected through the fuel clause. Rule 25-6.0131(1)(a.), F.A.C., specifies that: "[e]ach investor-owned electric company shall pay a regulatory assessment fee in the amount of .00072 of gross operating revenues derived from intrastate business, excluding sales for resale between public utilities, municipal electric utilities, and rural electric cooperatives or any combination thereof."[13]

The record evidence applicable to DEF on this topic was proffered by DEF witness Menendez. (EXH 7) Staff has verified that the correct tax factor (1 + .00072) was applied to the appropriate projected amount of fuel-related revenue to be collected for the period of January 2021 through December, 2021. Further, staff notes that while not specifically identified as a "stand-alone" issue, the specific revenue tax factor identified in this issue also applies to the revenue collected through the capacity clause which the Commission will review later in this recommendation (Issue 31).

Conclusion

Staff recommends that the appropriate revenue tax factor to be applied in calculating DEF's levelized fuel factor for the period of January 2021 through December 2021 is 1.00072.

[13]25-6.0131, F.A.C., *Regulatory Assessment Fees; Investor-owned Electric Companies, Municipal Electric Utilities, Rural Electric Cooperatives*.

Issue 20: What are the appropriate levelized fuel cost recovery factors for the period January 2021 through December 2021?

Recommendation: Staff recommends the appropriate levelized fuel and purchased power cost recovery factor needed to recover the projected cost of fuel and purchased power for the period of January 2021 through December 2021 is 3.090 cents per kWh. (Higgins)

Position of the Parties

DEF: 3.090 cents/kWh (adjusted for jurisdictional losses).

OPC/FIPUG: The levelized fuel cost recovery factors for the period January 2021 through December 2021 should reflect an adjustment for the overcollection of $16.1 million (along with a reasonable estimate of interest (subject to true-up in a subsequent proceeding)) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.

PCS Phosphate: Pursuant to Order No. PCS-2020-0368-FOF-EI, DEF's cost recovery amounts for January 2021 through December 2021 should be reduced by $16.1 million, plus interest, to credit through the fuel factor costs relating to the replacement power and de-rating of Bartow Unit 4.

Staff Analysis:

Parties' Arguments

DEF's argument in its post-hearing brief is unchanged from its position shown in the prehearing order and as listed above.[14] DEF believes the appropriate levelized fuel cost recovery factor for 2021 is 3.090 cents per kWh. (DEF BR 6)

The Joint Parties' argument in its post-hearing brief is the fuel cost recovery factor for 2021 should reflect an adjustment for the over-collection of $16.1 million with interest emanating from the 2017 outage of Bartow Unit 4. (Joint Parties BR 5)

PCS Phosphate argued in its post-hearing brief, that pursuant to Order No. PSC-2020-0368-FOF-EI, DEF's cost recovery amounts for January 2021 through December 2021 should be reduced by $16.1 million, plus interest, to credit for replacement power and de-rating costs due to the outage of Bartow Unit 4. (PCS Phosphate BR 2)

Analysis

The purpose of this issue is to determine the appropriate levelized fuel cost recovery factor needed to recover the total projected net cost of fuel and purchased power for the period of January 2021 through December 2021. Included in the levelized fuel cost recovery factor are the total jurisdictional fuel and purchase power cost (adjusted for line losses), total true-up, revenue tax, and the GPIF component. The aforementioned components of the fuel cost recovery factor were spread evenly (levelized) across the 2021 (12-month) jurisdictional megawatt-hour (MWh) sales

[14]Order No. PSC-2020-0415-PHO-EI.

forecast of 39,588,176 MWh (or 39,588,176,000 kilowatt-hours), to arrive at the proposed rounded levelized fuel cost recovery factor of 3.090 cents per kWh. (EXH 7)

Concerning the arguments brought forth by the Joint Parties and PCS Phosphate in regards to Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI, the Commission issued a stay of these orders during the December 1, 2020 Commission Conference. Thus, there are currently no additional or new matters to discuss pending the completion of DEF's appeal of Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI.

The record evidence in this proceeding, as proffered by DEF witnesses Menendez and Lewter, indicates that the appropriate levelized fuel cost recovery factor needed to recover the total projected net cost of fuel and purchased power for the period of January 2021 through December 2021 is 3.090 cents per kWh. (EXH 2, EXH 6, EXH 7, EXH 8) Staff notes its recommendation on this issue is consistent with its recommendations on Issues: 8, 9, 10, 11, 16, 18, and 19.

Conclusion

Staff recommends the appropriate levelized fuel and purchased power cost recovery factor needed to recover the projected cost of fuel and purchased power for the period of January 2021 through December 2021 is 3.090 cents per kWh.

Issue 21: What are the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class?

Recommendation: Staff recommends the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class for the period January 2021 through December 2021 are as listed in Table 21-1. (Higgins)

Position of the Parties

DEF:

Group	Delivery Voltage Level	Line Loss Multiplier
A	Transmission	0.9800
B	Distribution Primary	0.9900
C	Distribution Secondary	1.0000
D	Lighting Service	1.0000

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine the appropriate line loss multipliers to apply in calculating the fuel cost recovery factors charged to each rate group/delivery voltage service level. Due to the physics involved, a certain quantity of electricity is lost during its transmission and distribution through the electric grid which leads to variations in efficiency levels of delivered electricity. Because DEF must provide enough electricity to meet customer demand which will inherently include a quantity of line loss/differences in delivery efficiencies, a portion of this loss is accounted for and reflected through the "line loss multiplier."

The record evidence in this proceeding, as proffered by DEF witness Menendez, indicates the fuel recovery line loss multipliers to be applied to the fuel cost recovery factors for the period of January 2021 through December 2021 are as shown in Table 21-1 below:

Table 21-1
DEF Fuel Recovery Line Loss Multipliers
January - December, 2021

Group	Delivery Voltage Level	Line Loss Multiplier
A	Transmission	0.98
B	Distribution Primary	0.99
C	Distribution Secondary	1.00
D	Lighting Service	1.00

Source: (EXH 7)

Conclusion

Staff recommends the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate group/delivery voltage level class for the period January 2021 through December 2021 are as listed in Table 21-1.

Issue 22: What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?

Recommendation: Staff recommends the appropriate fuel cost recovery factors for each rate class/delivery voltage level class, adjusted for line losses, are as listed in Table 22-1. (Higgins, Draper)

Position of the Parties

DEF:

Fuel Cost Factors (cents/kWh)						
					Time of Use	
Group	Delivery Voltage Level	First Tier Factor	Second Tier Factors	Levelized Factors	On-Peak	Off-Peak
A	Transmission	--	--	3.032	3.793	2.689
B	Distribution Primary	--	--	3.063	3.832	2.717
C	Distribution Secondary	2.811	3.811	3.094	3.871	2.744
D	Lighting Secondary	--	--	2.955	--	--

OPC/FIPUG: The allocation of fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses should reflect an adjustment for the overcollection of $16.1 million (along with a reasonable estimate of interest (subject to true-up in a subsequent proceeding)) in imprudently incurred replacement power costs emanating from the 2017 outage at Bartow Unit 4.

PCS Phosphate: Pursuant to Order No. PSC-2020-0368-FOF-EI, DEF's cost recovery amounts for January 2021 through December 2021 should be reduced by $16.1 million to credit through the fuel factor costs relating to the replacement power and de-rating of Bartow Unit 4. To the extent that this reduction in allowed cost recovery reduces the fuel cost recovery factors for DEF, those factors should be adjusted.

Staff Analysis:

Parties' Arguments

DEF believes the appropriate fuel cost recovery factors for 2021 are as listed above. (DEF BR 6)

The Joint Parties' argued in their post-hearing brief that the allocation of fuel cost recovery for each service level in 2021 should reflect an adjustment of approximately $16.1 million with interest emanating from the 2017 outage at Bartow Unit 4. (Joint Parties BR 6)

PCS Phosphate argued that Pursuant to Order No. PSC-2020-0368-FOF-EI, DEF's cost recovery amount for January 2021 through December 2021 should be reduced by approximately $16.1 million for replacement power and de-rating costs due to the April 2017 outage of Bartow Unit 4 and that the fuel cost recovery factor should be commensurably adjusted downward. (PCS Phosphate BR 3)

Analysis

The purpose of this issue is to identify the proposed fuel cost recovery factors for each rate group. This issue is primarily determined by the Commission's decision on Issue 18. The other component, which is not specifically voted on by the Commission, is DEF's effective 2021 jurisdictional sales forecast. Further, "tiered" and "time-of-use" factors, relative to the levelized factors, are also developed. Time-of-use factors involve calculating on- and off-peak multipliers, which is accomplished by ascertaining both applicable on-peak and off-peak average marginal fuel costs and dividing those figures by the applicable total average marginal fuel cost. For 2021, DEF's proposed on- and off-peak multipliers are 1.251 and 0.887 respectively.

The record evidence in this proceeding, as proffered by DEF witness Menendez, indicates the proposed fuel cost recovery factors for each rate group/delivery voltage level adjusted for line losses for the period January 2021 through December 2021, are as listed in Table 22-1 below:

Table 22-1
Fuel Cost Recovery Factors for the period January-December, 2021

Group	Delivery Voltage Level	Fuel Cost Recovery Factors (cents/kWh)			Time of Use (cents/kWh)	
		First Tier	Second Tier	Levelized	On-Peak	Off-Peak
A	Transmission	--	--	3.032	3.793	2.689
B	Distribution Primary	--	--	3.063	3.832	2.717
C	Distribution Secondary	2.811	3.811	3.094	3.871	2.744
D	Lighting Service	--	--	2.955	--	--

Source: (EXH 7)

Concerning the arguments brought forth by the Joint Parties and PCS Phosphate in regards to Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI, the Commission issued a stay of these orders during the December 1, 2020 Commission Conference. Thus, there are currently no additional or new matters to discuss pending the completion of DEF's appeal of Order Nos. PSC-2020-0368-FOF-EI and PSC-2020-0368A-FOF-EI.

Conclusion

Staff recommends the appropriate fuel cost recovery factors for each rate class/delivery voltage level class, adjusted for line losses, are as listed in Table 22-1.

Issue 23A: What is the appropriate net book value of retired Plant Crystal River South (Units 1 and 2) assets to be recovered over a one-year period as approved by Order No. PSC-2017-0451-AS-EU?

Recommendation: Staff recommends the appropriate net book value of the retired Crystal River South assets to be included in the 2021 capacity factors is $80,592,431. (Higgins)

Position of the Parties

DEF: The estimated CR1&2 net book value of retired assets recovered over a one-year period in 2021 is $80,592,431; the final CR1&2 net book value will be included in DEF's 2020 Final True-Up filing.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: This issue addresses the remaining/stranded net book value (NBV) associated with two of DEF's now-retired generating units, namely Crystal River Units 1&2, or Crystal River South (CRS). CRS was retired in 2019 coinciding with the in-service of the "Citrus County or Crystal River Energy Complex." Authorization for capacity clause recovery of the CRS-associated NBV came with the approval of DEF's 2017 Second Revised and Restated Settlement Agreement (2017 Settlement).[15] The 2017 Settlement specifies December 31, 2020, as the end-point to develop the final NBV of CRS assets for accounting purposes/amount eligible for capcaity cost recovery. The record evidence in this proceeding, as proffered by DEF witness Menendez, indicates the proposed NBV of CRS assets to be included for capacity clause recovery in 2021 is $80,592,431. (EXH 7)

Conclusion

Staff recommends the appropriate net book value of the retired Crystal River South assets to be included in the 2021 capacity factors is $80,592,431.

[15]Order No. PSC-2017-0451-AS-EU, issued November 20, 2017, in Docket No. 20170183-EI, *In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC*; Docket No. 20100437-EI, *In re: Examination of the outage and replacement fuel/power costs associated with the CR3 steam generator replacement project, by Progress Energy Florida, Inc.*; Docket No. 20150171-EI, *In re: Petition for issuance of nuclear asset-recovery financing order, by Duke Energy Florida, Inc. d/b/a Duke Energy*; Docket No. 20170001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Docket No. 20170002-EG, *In re: Energy conservation cost recovery clause*; Docket No. 20170009-EI, *In re: Nuclear cost recovery clause*.

Issue 23B: What is the appropriate amount of costs for the Independent Spent Fuel Storage Installation (ISFSI) that DEF should be allowed to recover through the capacity cost recovery clause pursuant to DEF's 2017 Settlement?

Recommendation: Staff recommends the CR3 ISFSI-associated cost to be included for capacity clause recovery in 2021 is $6,879,837. (Higgins)

Position of the Parties

DEF: $6,879,837.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine the amount of amortization associated with the Crystal River Unit No. 3 (CR3) Independent Spent Fuel Storage Installation (ISFSI) to be included for recovery through the capacity clause in 2021. The authorization for capacity clause recovery of the CR3 ISFSI-associated revenue requirement came with the approval of DEF's 2017 Settlement.[16]

The record evidence in this proceeding, as proffered by DEF witness Menendez, indicates the amount of amortization associated with the CR3 ISFSI to be included in the 2021 capacity factors is $6,879,837. This annual recovery amount consists of ISFSI investment, return, and revenue tax.

Conclusion

Staff recommends the CR3 ISFSI-associated cost to be included for capacity clause recovery in 2021 is $6,879,837.

[16]Order No. PSC-2017-0451-AS-EU.

Issue 23C: Should the Commission approve the Third Implementation Stipulation and, if approved, what is the amount of state corporate income tax savings that should be refunded to customers through the capacity clause in 2021?

Recommendation: Staff recommends the Commission approve the proposed Third Implementation Stipulation regarding the 2019 Florida State Corporate Income Tax reduction. Approving the proposed Third Implementation Stipulation results in a total refund to customers in the amount of $8,379,918. (Higgins)

Position of the Parties

DEF: Yes, the Commission should approve the Third Implementation Stipulation and $8,379,918 of income tax savings refunded to customers through the capacity clause in 2021.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Yes, the Commission should approve the Third Implementation Stipulation filed in this docket on July 27, 2020. PCS Phosphate was a signatory to that agreement.

Staff Analysis: The purpose of this issue is to account for the impact of the three-year Florida State Corporate Income Tax reduction that went into effect in 2019. Staff notes the Florida State Corporate Income Tax rate was reduced from 5.5 percent to 4.458 percent for calendar years 2019, 2020, and 2021. A provision addressing and accounting for possible future changes in tax rates was part of DEF's 2017 Settlement.[17]

As indicated by the phrasing of this issue, the aforementioned tax-related accounting treatment outlined in the Third Implementation Stipulation was agreed to by the parties to the 2017 Settlement, which includes all the above-listed parties to this issue. Although the OPC, and by extension FIPUG, "takes no position on this issue nor does it have the burden of proof related to it," staff notes that both groups signed the Third Implementation Stipulation. (EXH 6) PCS Phosphate (as "White Springs Agricultural Chemical, Inc.") also signed the Third Implementation Stipulation, and supports its approval. (EXH 6)

Staff notes the proposed Third Implementation Stipulation was filed on July 27, 2020, as an appendix to DEF witness Menendez' actual/estimated testimony. (EXH 6) The total proposed refund to DEF's customers associated with the three-year Florida State Corporate Income Tax reduction is $8,379,918, which is the amount proposed for inclusion in the recoverable 2021 capacity cost (Issue 30).

[17]Order No. PSC-2017-0451-AS-EU.

Conclusion

Staff recommends the Commission approve the proposed Third Implementation Stipulation regarding the 2019 Florida State Corporate Income Tax reduction. Approving the proposed Third Implementation Stipulation results in a total refund to customers in the amount of $8,379,918.

Issue 23D: What adjustment amounts should the Commission approve to be refunded through the capacity clause in 2021 for the Columbia SoBRA I project approved in Docket No. 20180149-EI and the DeBary, Lake Placid, and Trenton SoBRA II projects approved in Docket No. 20190072-EI?

Recommendation: Staff recommends the total credit amount associated with solar plants: Columbia, DeBary, Lake Placid, and Trenton, to be included in the 2021 capacity factors is $1,023,015. (Higgins)

Position of the Parties

DEF: $1,023,015.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: This purpose of the issue is to identify the specific true-up amounts associated with a number of DEF's SoBRA-recovered projects, namely plants: Columbia, DeBary, Lake Placid, and Trenton. These projects were approved by Order Nos. PSC-2019-0159-FOF-EI and PSC-2019-0292-FOF-EI.[18]

The initial authorization for the DEF-specific SoBRA framework came in approving the 2017 Settlement.[19] As part of the SoBRA framework, DEF is required to perform a true-up if the actual/final capital expenditures are lower than the approved capital expenditures, or if the facility in-service dates vary from those originally assumed. Any credit/refund is to be effectuated through the capacity clause.

The record evidence in this proceeding, as proffered by DEF witness Menendez, indicates the total proposed SoBRA-related credit to be included in the 2021 total recoverable capacity cost (Issue 30) is $1,023,015.

[18]Order No. PSC-2019-0159-FOF-EI, issued April 30, 2019, in Docket No. 20180149-EI, *In re: Petition for a limited proceeding to approve first solar base rate adjustment, by Duke Energy Florida, LLC*, and Order No. PSC-2019-0292-FOF-EI, issued July 22, 2019, in Docket No. 20190072-EI, *In re: Petition for a limited proceeding to approve second solar base rate adjustment, by Duke Energy Florida, LLC.*
[19]Order No. PSC-2017-0451-AS-EU.

Conclusion

Staff recommends the total credit amount associated with solar plants: Columbia, DeBary, Lake Placid, and Trenton, to be included in the 2021 capacity factors is $1,023,015.

Issue 27: What are the appropriate final capacity cost recovery true-up amounts for the period January 2019 through December 2019?

Recommendation: Staff recommends the appropriate final capacity cost recovery true-up amount for the period January 2019 through December 2019 is an under-recovery of $797,779. (Higgins)

Position of the Parties

DEF: $797,779 under-recovery.

FPUC: No position.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine DEF's final capacity revenue true-up amount for the period of January 2019 through December 2019. This final capacity revenue true-up represents the difference between calendar-year 2019 actual capacity costs and period-applicable capacity revenues that were collected to cover such cost.

The record evidence in this proceeding, as proffered by DEF witness Menendez, indicates the actual capacity revenue true-up amount for the period January 2019 through December 2019 is an under-recovery of $797,779. (EXH 3)

Conclusion

Staff recommends the appropriate final capacity cost recovery true-up amount for the period January 2019 through December 2019 is an under-recovery of $797,779.

Issue 28: What are the appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2020 through December 2020?

Recommendation: Staff recommends the appropriate capacity cost recovery actual/estimated true-up amount for the period January 2020 through December 2020 is an over-recovery of $334,694. (Higgins)

Position of the Parties

DEF: $334,694 over-recovery.

FPUC: No position.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine DEF's actual/estimated capacity revenue true-up amount for the period of January 2020 through December 2020. The actual/estimated capacity revenue true-up is based on six months (January-June 2020) of actual capacity cost- and revenue-related data, and a re-projected six months (July-Dec. 2020) of capacity cost- and revenue-related data relative to the projection performed the prior year.

The record evidence in this case proceeding, as proffered by DEF witness Menendez, indicates the actual/estimated capacity revenue true-up amount for the period January 2020 through December 2020 is an over-recovery of $334,694. (EXH 6)

Conclusion

Staff recommends the appropriate capacity cost recovery actual/estimated true-up amount for the period January 2020 through December 2020 is an over-recovery of $334,694.

Issue 29: What are the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2021 through December 2021?

Recommendation: Staff recommends the appropriate total capacity cost recovery true-up amount to be collected during the period January 2021 through December 2021 is an under-recovery of $463,084. (Higgins)

Position of the Parties

DEF: $463,084 under-recovery.

FPUC: No position.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine the net amount of prior and current period over- or under-collected revenue to be accounted for in setting the 2021 capacity factors.

As discussed in Issue 27, the record evidence in this proceeding indicates the final capacity revenue true-up amount for the period January 2019 through December 2019 is an under-recovery of $797,779. (EXH 3) Further, as discussed in Issue 28, the actual/estimated capacity revenue true-up amount for the period January 2020 through December 2020 is an over-recovery of $334,694. (EXH 6) Thus the total true-up to be applied to the January through December 2021 capacity cost recovery factors is a net under-recovery of $463,084.

Conclusion

Staff recommends the appropriate total capacity cost recovery true-up amount to be collected during the period January 2021 through December 2021 is an under-recovery of $463,084.

Issue 30: What are the appropriate projected total capacity cost recovery amounts for the period January 2021 through December 2021?

Recommendation: Staff recommends the appropriate projected total capacity cost amount for the period January 2021 through December 2021 is $479,983,370. (Higgins)

Position of the Parties

DEF: $479,983,370.

FPUC: No position.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to determine the projected total capacity cost recovery amount for the period January 2021 through December 2021.

The total projected 2021 jurisdictional capacity cost consists of general and other capacity-related costs, CRS costs (Issue 23A), as well as tax- and SoBRA-related credits (Issues 23C-D). The amount of revenue required (i.e. after incorporating the true up, taxes, and ISFSI adjustment) to meet the total projected capacity cost is addressed in Issue 31.

The record evidence in this proceeding, as proffered by DEF witness Menendez, indicates the projected total capacity cost for the period of January 2021 through December 2021 is $479,983,370. (EXH 7)

Conclusion

Staff recommends the appropriate projected total capacity cost amount for the period January 2021 through December 2021 is $479,983,370.

Issue 31: What are the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2021 through December 2021?

Recommendation: Staff recommends the appropriate projected net purchased power capacity cost to be included in the cost recovery factor for the period of January 2021 through December 2021 is $487,677,167. (Higgins)

Position of the Parties

DEF: $487,677,167.

FPUC: No position.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to identify the appropriate net amount of capacity costs to be included in developing the recovery factors for the period of January 2021 through December 2021. This issue is essentially a "fall-out" issue, whereas the dollar values of prior decisions are tabulated and summed to arrive at the recommended amount to recover. The relevant components required to calculate the 2021 capacity cost recovery amount are: total jurisdictional net capacity costs, true-up, and revenue tax.

The record evidence in this proceeding, consistent with staff's recommendations on Issues: 19, 23A-D, and 27-30, indicates the appropriate projected net purchased power capacity cost to be included in setting the cost recovery factors for the period of January 2021 through December 2021 is $487,677,167. (EXH 3, EXH 7) The derivation of DEF's 2021 proposed capacity cost recovery amount is shown in Table 31-1 below:

Table 31-1
DEF 2021 Capacity Cost Recovery

Cost Component	Amount
Projected Total Capacity Costs (Issues: 23A-D and 30)	$486,863,207
Total True-up (Issues: 27, 28, and 29)	463,084
Revenue Tax (*Issue 19*)	350,875
Total*	$487,677,167

Sources: (EXH 3, EXH 7)
*May not compute exactly due to rounding.

Conclusion

Staff recommends the appropriate projected net purchased power capacity cost to be included in the cost recovery factor for the period of January 2021 through December 2021 is $487,677,167.

Issue 32: What are the appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2021 through December 2021?

Recommendation: Staff recommends the appropriate jurisdictional separation factors for capacity revenues and costs to be included in the 2021 recovery factor are as listed in Table 32-1. (Higgins)

Position of the Parties

DEF: Base – 92.885%, Intermediate – 72.703%, Peaking – 95.924%, consistent with the 2017 Settlement approved in Order No. PSC-2017-0451-AS-EI.

FPUC: No position.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to identify the appropriate jurisdictional separation factors for application in the capacity clause.

A provision addressing demand-related jurisdictional separation factors was part of DEF's 2017 Settlement.[20] As specified in the 2017 Settlement, and proffered by DEF witness Menendez, the agreed upon demand-related jurisdictional separation factors applicable to cost recovery clauses are shown in Table 32-1 below:

Table 32-1
DEF Jurisdictional Separation Factors - Capacity
January - December, 2021

Classification	Separation Factor (%)
Base	92.885
Intermediate	72.703
Peaking	95.924

Sources: (EXH 7) and Order No. PSC-2017-0451-AS-EU.

[20]Order No. PSC-2017-0451-AS-EU.

Conclusion

Staff recommends the appropriate jurisdictional separation factors for capacity revenues and costs to be included in the 2021 recovery factor are as listed in Table 32-1.

Issue 33: What are the appropriate capacity cost recovery factors for the period January 2021 through December 2021?

Recommendation: Staff recommends the appropriate capacity cost recovery factors for the period January 2021 through December 2021 are as listed in Table 33-1. (Higgins, Draper)

Position of the Parties

DEF:

Rate Class	CCR Factor
Residential	1.405 cents/kWh
General Service Non-Demand	1.342 cents/kWh
@ Primary Voltage	1.329 cents/kWh
@ Transmission Voltage	1.315 cents/kWh
General Service 100% Load Factor	0.808 cents/kWh
General Service Demand	4.20 $/kW-month
@ Primary Voltage	4.16 $/kW-month
@ Transmission Voltage	4.12 $/kW-month
Curtailable	1.22 $/kW-month
@ Primary Voltage	1.21 $/kW-month
@ Transmission Voltage	1.20 $/kW-month
Interruptible	3.50 $/kW-month
@ Primary Voltage	3.47 $/kW-month
@ Transmission Voltage	3.43 $/kW-month
Standby Monthly	0.404 $/kW-month
@ Primary Voltage	0.400 $/kW-month
@ Transmission Voltage	0.396 $/kW-month
Standby Daily	0.192 $/kW-month
@ Primary Voltage	0.190 $/kW-month
@ Transmission Voltage	0.188 $/kW-month
Lighting	0.172 cents/kWh

FPUC: No position.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: Agree with OPC.

Staff Analysis: The purpose of this issue is to identify the 2021 capacity cost recovery factors for each rate class. This issue is primarily determined by the Commission's votes on Issues 31 and 32, which include underlying issues. Further, DEF's 2017 Settlement contained a provision addressing the demand-related cost allocation methodology to be used for capacity clause rate-making purposes.[21] The 2017 Settlement specified that DEF will utilize the "12 Coincident Peak Load and 1/13 Average Demand" cost allocation methodology. The other component utilized for rate making in this issue, which is not specifically voted on by the Commission, is DEF's effective 2021 class-specific jurisdictional sales forecast.

The proposed capacity cost recovery factors were proffered by DEF witness Menendez and are shown by rate class in Table 33-1 below:

[21]Order No. PSC-2017-0451-AS-EU.

Table 33-1
DEF Capacity Cost Recovery Factors
January-December, 2021

Rate Class		2021 Capacity and CR3 ISFSI Cost Recovery Factors	
		Cents per kWh	**Dollars per kW-month**
Residential (RS-1, RST-1, RSL-1, RSL-2, RSS-1) At Secondary Voltage		1.405	
General Service Non-Demand (GS-1, GST-1)			
	At Secondary Voltage	1.342	
	At Primary Voltage	1.329	
	At Transmission Voltage	1.315	
General Service (GS-2)		0.808	
Lighting (LS-1)		0.172	
General Service Demand (GSD-1, GSDT-1, SS-1)			
	At Secondary Voltage		4.20
	At Primary Voltage		4.16
	At Transmission Voltage		4.12
Curtailable (CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3)			
	At Secondary Voltage		1.22
	At Primary Voltage		1.21
	At Transmission Voltage		1.20
Interruptible (IS-1, IST-1, IS-2, IST-2, SS-2)			
	At Secondary Voltage		3.50
	At Primary Voltage		3.47
	At Transmission Voltage		3.43
Standby Monthly (SS-1, 2, 3)			
	At Secondary Voltage		0.404
	At Primary Voltage		0.400
	At Transmission Voltage		0.396
Standby Daily (SS-1, 2, 3)			
	At Secondary Voltage		0.192
	At Primary Voltage		0.190
	At Transmission Voltage		0.188

Source: (EXH 7)

Conclusion

Staff recommends the appropriate capacity cost recovery factors for the period January 2021 through December 2021 are as listed in Table 33-1.

Issue 34: What should be the effective date of the fuel adjustment factors and capacity cost recovery factors for billing purposes?

Recommendation: Staff recommends the new fuel and capacity factors should be effective beginning with the first billing cycle for January 2021 through the last billing cycle for December 2021. (Higgins)

Position of the Parties

DEF: The new factors should be effective beginning with the first billing cycle for January 2021 through the last billing cycle for December 2021. The first billing cycle may start before January 1, 2021, and the last billing cycle may end after December 31, 2021, so long as each customer is billed for twelve months regardless of when the factors became effective.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: No position.

Staff Analysis: The purpose of this issue is to establish for billing purposes the effective date of the fuel adjustment factors and capacity cost recovery factors the Commission deems appropriate in this proceeding.

Staff believes the new factors should be effective beginning with the first billing cycle for January 2021 through the last billing cycle for December 2021. The first billing cycle may start before January 1, 2021, and the last cycle may be read after December 31, 2021, so that each customer is billed for twelve months regardless of when the recovery factors became effective. Further, the new factors should continue to be effective until modified by the Commission.

Conclusion

Staff recommends the new fuel and capacity factors should be effective beginning with the first billing cycle for January 2021 through the last billing cycle for December 2021.

Issue 35: Should the Commission approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding?

Recommendation: Yes. Staff recommends the Commission approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be reasonable in this proceeding. (Draper, Higgins)

Position of the Parties

DEF: Yes. The Commission should approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding. The Commission should direct Staff to verify that the revised tariffs are consistent with the Commission decision.

OPC: OPC takes no position on this issue nor does it have the burden of proof related to it. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or Staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on this issue, either in this docket, in an order of the Commission or in a representation to a Court.

FIPUG: Adopt the position of OPC.

PCS Phosphate: No position.

Staff Analysis: The purpose of this issue is to determine if the Commission should approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding.

Staff believes the Commission should approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be reasonable in this proceeding.

Conclusion

Staff recommends the Commission approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be reasonable in this proceeding.

Issue 36: Should this docket be closed?

Recommendation: No. While a separate docket number is assigned each year for administrative convenience, this is a continuing docket and should remain open. (Brownless)

Position of the Parties

DEF: Yes.

OPC/FIPUG: No. The docket should remain open until any action approved, if at all, by the Commission is completed satisfactorily.

PCS Phosphate: No position.

Staff Analysis:

Parties' Arguments

DEF stated that OPC, PCS Phosphate, and FIPUG took "no position" on this issue at the Prehearing Conference. Therefore, in accord with Section VI.C. of Order No. PSC-2020-0041-PCO-EI, Order Establishing Procedure, these parties are prohibited from contesting DEF's position on, or briefing, this issue.[22] (DEF BR 5)

The Joint Parties have briefed this issue and stated that the docket should remain open pending completion of any action the Commission may require. (Joint Parties BR 6)

PCS Phosphate did not brief this issue nor take a position on it at the Prehearing Conference.

Analysis

DEF is correct that parties are unable to take a position on, or to brief, issues on which they did not take a position by the date set at the Prehearing Conference. DEF is also correct that OPC, FIPUG and PCS Phosphate did not take positions on this issue. However, staff recommends that DEF's position that the docket be closed be rejected. While a separate docket number is assigned each year for administrative convenience, this is a continuing docket and should remain open. Therefore, staff recommends that this docket remain open.

Conclusion

While a separate docket number is assigned each year for administrative convenience, this is a continuing docket and staff recommends that it remain open.

[22]Order No. PSC-2020-0041-PCO-EI, issued January 31, 2020, in Docket No. 20200001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

FLORIDA PUBLIC SERVICE COMMISSION

Item 4

VOTE SHEET

FILED 12/4/2020
DOCUMENT NO. 13101-2020
FPSC - COMMISSION CLERK

December 1, 2020

Docket No. 20200001-EI – Fuel and purchased power cost recovery clause with generating performance incentive factor.

Issue 1: Should Duke Energy Florida, LLC's Motion for Stay Pending Judicial Review be granted?
Recommendation: Yes. DEF has complied with the requirements of Rule 25-22.061(1), F.A.C., and should be granted a stay of the provisions of Order No. PSC-2020-0368A-FOF-EI requiring a refund of $16.1 million associated with the 2017 Bartow Unit 4 outage. As a condition of the stay, DEF should be required to provide adequate security in the form of a corporate undertaking in the amount of the refund plus interest as determined by Rule 25-6.109, F.A.C.

APPROVED

COMMISSIONERS ASSIGNED: **All Commissioners**

COMMISSIONERS' SIGNATURES

MAJORITY	DISSENTING
Julie Brown	
Donald J. Polmann	

REMARKS/DISSENTING COMMENTS:

Docket No. 20200001-EI – Fuel and purchased power cost recovery clause with generating performance incentive factor.

(Continued from previous page)

Issue 2: Should this docket be closed?
Recommendation: No. At this time there are outstanding issues for DEF to be voted on in this docket at the Special Agenda Conference set for December 15, 2020, which are contingent upon the Commission's vote on the Motion for Stay Pending Judicial Appeal at issue here.

APPROVED

SUPREME COURT OF FLORIDA

DUKE ENERGY FLORIDA, LLC.,	)	
	)	
	)	Case No.: **SC20-1601**
Appellant.	)	
	)	LT No: **20200001-EI**
vs.	)	
	)	
GARY F. CLARK, ETC, ET AL.,	)	
	)	
	)	
Appellee.	)	
	)	

CERTIFICATE OF RECORD

I, Adam J. Teitzman, Commission Clerk and Custodian of Records for the Office of Commission Clerk, Florida Public Service Commission, for the State of Florida, do certify that the foregoing pages 1 through 2,971, inclusive, contains a true and correct copy of such records in the above-styled matter as appears in the files in my office and that have been included in said record.

CERTIFIED this 22nd day of February, 2021, in Tallahassee, Leon County, Florida.

Adam J, Teitzman, Commission Clerk
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850
(850)413-6728

FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF COMMISSION CLERK

DOCUMENT NUMBER ASSIGNMENT*

CONFIDENTIAL

FILED DATE: 2/18/2020

DOCKET NO.: 20200001-EI

DOCUMENT NO.: 00962-2020, 00963-2020, 00964-2020

DOCUMENT DESCRIPTION:

TRANSCRIPT (CONFIDENTIAL) - Volume 1, pages 1 to 156, of 2/4/20 final hearing held at DOAH before The Honorable Lawrence P. Stevenson [Case No. 19-006022]

***This document number has been assigned to a confidential document. For further information, contact the Office of Commission Clerk.**

E-MAIL: CLERK@PSC.STATE.FL.US PHONE NO. (850) 413-6770 FAX NO. (850) 717-0114

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

RE IN: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR,

Petitioner,

vs. CASE NO. 19-6022

**,

Respondent.
_________________________________/

VOLUME 1

PAGES 1 - 156

PROCEEDINGS: Administrative Hearing

BEFORE: Honorable Lawrence P. Stevenson

DATE: February 4, 2020

TIME: Commenced: 8:55 A.M.

LOCATION: Division of Administrative Hearings
1230 Apalachee Parkway
The DeSoto Building,
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter and
Notary Public in and for the
State of Florida at Large

PREMIER REPORTING
114 W. 5TH AVENUE
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J.R. KELLY, PUBLIC COUNSEL; CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL; and THOMAS A. (Tad) DAVID, ESQUIRE, Office of Public Counsel, c/o the Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

JON C. MOYLE, JR., ESQUIRE, and KAREN A. PUTNAL, ESQUIRE, Moyle Law Firm, P.A., 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

JAMES WALTER BREW, ESQUIRE, Stone Law Firm, Eighth Floor, West Tower, 1025 Thomas Jefferson Street Northwest, Washington, DC 20007, appearing on behalf of White Springs Agricultural Chemicals, PCS Phosphate.

SUZANNE BROWNLESS, and BIANCA LHERISSON, ESQUIRES, FPSC General Counsel's Office, appearing on behalf of the Florida Public Service Commission Staff;

KEITH HETRICK GENERAL COUNSEL, DEPUTY GENERAL COUNSEL, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, adviser to the Florida Public Service Commission.

INDEX TO WITNESSES

INDEX TO EXHIBITS

NO.	DESCRIPTION	IDENTIFIED	ADMITTED
114	Revised Comprehensive Exhibit List	11	11
115	RCA draft	35	
116	3/18/2015 40-inch blade telemetry	35	

*Huh-uh is a negative response
*Uh-huh is a positive response

P R O C E E D I N G S

THE COURT: We will go ahead and call the hearing to order.

We are here today in the case styled In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor. It's DOAH case number 19-6022. It's a Public Service Commission case.

My name is Lawrence Stevenson. I am the Administrative Law Judge assigned to hear the case. And I guess at the outset, we should get appearances entered. I am just going to go in the order that's in our little -- we've got a little cheat sheet here for how we are going to handle this proceeding.

Representing Duke Energy.

MR. BERNIER: Good morning, Judge Stevenson, Matt Bernier on behalf of Duke Energy.

MR. HERNANDEZ: Good morning, Your Honor. Daniel Hernandez with Shutts & Bowen on behalf of Duke Energy.

MR. BERNIER: And, Judge, I would also enter an appearance for Dianne Triplett, who will be here shortly.

THE COURT: Okay. I have got her, so that's good.

MR. HERNANDEZ: And, Your Honor, seated with us is Mr. Jeff Swartz. He's a representative of the company, and also will be testifying as a witness.

MR. SWARTZ: Good morning, Your Honor.

THE COURT: A face with all the testimony I have read. That's good.

And Office of Public Counsel.

MR. REHWINKEL: Good morning, Your Honor, Charles Rehwinkel with the Office of Public Counsel.

MR. DAVID: And Thomas A. "Tad" David with the Office of Public Counsel.

MR. BREW: I am not with the Office of Public Counsel.

THE COURT: Okay. Very good.

MR. REHWINKEL: And, Your Honor, I would like to enter an appearance for J.R. Kelly, the Public Counsel, he's here with us.

THE COURT: Okay. I have got Mr. Kelly checked off as well.

And for -- I still don't have the acronym down. Is it FIPUG?

MR. MOYLE: FIPUG, it's Florida Industrial

Power Users Group.

THE COURT: I am more comfortable saying that.

MR. MOYLE: Right, and that's fine. Judge Peterson, we recently had a case and he called us Florida Industrial, and so we will answer to anything, Your Honor.

THE COURT: That's good. With me, I think power users, whatever.

MR. MOYLE: So I'm Jon Moyle with the Moyle Law Firm representing the industrial users, and Karen Putnal of our firm is also here, I would like to enter an appearance for her as well.

THE COURT: Okay. Very good.

And PCS Phosphate.

MR. BREW: Yes, Your Honor. For White Springs Agricultural Chemicals, PCS Phosphate, I am James Brew from Stone Mattheis Xenopoulos & Brew.

THE COURT: Very good.

And last but not least, the Public Service Commission.

MS. BROWNLESS: Good morning, Your Honor. My name is Suzanne Brownless, appearing on behalf of the Florida Public Service Commission staff. Also appearing is Bianca Lherisson. And we would like to enter a notice of appearance for Keith Hetrick, our General Counsel.

THE COURT: Okay. Very good.

And our next order of business I guess is to close the hearing. I have to rely on counsel to be my police in this respect. I am assuming that, as of now, everyone is in the room belongs in the room, is that correct?

MR. BERNIER: I believe that's correct, and I have asked the counsel for the other representatives to let me know if somebody enters and they are a member of their party so we don't have to disrupt anything.

THE COURT: Okay. That's fine.

MR. BERNIER: But if somebody does that we don't know, we will let you know.

THE COURT: That's fine. I guess I will give you a high sign if I see someone.

Mr. Rehwinkel.

MR. REHWINKEL: Your Honor, I don't know if our microphones are working. The light is not coming on.

THE COURT: Gee. That's not in my bailiwick. I mean, I can hear you fine.

MR. REHWINKEL: Okay.

THE COURT: We are not -- I just don't know if the court reporter can.

COURT REPORTER: I'll let you know.

THE COURT: Okay. The first break, I will go talk to somebody about it and see what we can do.

MR. DAVID: The switch was off.

THE COURT: Oh, is that it?

MR. DAVID: Yeah.

THE COURT: There is a little green light that comes on.

MR. REHWINKEL: Thank you.

THE COURT: Okay. Well, we've got exhibits. Did we want to get the exhibits up here at this time?

MS. BROWNLESS: Yes, Your Honor.

As you know, we've already stipulated to exhibits on the comprehensive exhibit list, Exhibit Nos. 1, 68 through 76, 80 through 82 and 100, and those have been previously provided to the Court and the parties.

We have other exhibits on the comprehensive exhibit list that have been marked for identification, and I believe the parties also think that there is no need to authenticate those documents. Do I have that correct?

MR. HERNANDEZ: That is correct, Your Honor.

MS. BROWNLESS: Okay. And so what we would like to do at this time is hand out a revised comprehensive exhibit list.

THE COURT: Okay.

MS. BROWNLESS: And at this time, we would like that marked as Exhibit No. 114 and ask that it be admitted into evidence.

THE COURT: Hearing no objections, we will mark the exhibit -- the revised comprehensive exhibit list as staff -- Commission staff Exhibit 114, and show it admitted.

(Whereupon, Exhibit No. 114 was marked for identification and received into evidence.)

MS. BROWNLESS: Thank you, Your Honor.

THE COURT: And I think that takes care of all of our business up to the opening statements.

I went through my usual list of questions that I ask at the beginning of a hearing, and I know this is not a conventional hearing. The only one that I sort of want an answer to, I think I know the answer to this, but I want it on the record is who has the burden, and what is the burden in this proceeding? I sort of assume it's probably Duke Energy and it's probably by a preponderance, but --

MR. BERNIER: Yes, sir.

THE COURT: -- do we have sort of agreement on that?

MR. BERNIER: Yes, sir, we agree with both of those.

MR. REHWINKEL: Yes, sir.

THE COURT: Okay. That takes care of any concerns that I had.

And at this time, I guess we can move on to opening statements. And was there agreement as to who goes first? I am assuming it would be Duke.

MR. BERNIER: I think so. So I will go ahead.

Thank you. Good morning, again, Judge Stevenson. Matt Bernier for Duke Energy.

The issues presented to you today can be boiled down to one overarching question, and is that did Duke Energy prudently operate the Bartow steam turbine? Now, the Public Service Commission's prudent standard asks did DEF act as a reasonable utility manager would given the information it knew or reasonably should have known at the time it acted?

And this is not a hindsight review, because with the benefit of hindsight, most reasonable people can identify something that they would do differently.

In this case, the preponderance of the evidence shows that DEF acted prudently at all times given the information DEF knew or should have known, because DEF, at all times, operated the machine in compliance with the manufacturer's guidelines, which is the standard industry practice.

Now, Duke Energy purchased the Bartow combined cycle steam turbine from Mitsubishi Power Systems. The steam turbine was designed for use by a third party, but that project never came to fruition, and the steam turbine was never delivered to the third party.

Prior to the purchase, Mitsubishi was responsible for ensuring the turbine was compatible and acceptable for the use at Bartow. They were also responsible for providing Duke Energy with the operating parameters for the unit. DEF was responsible for operating the unit within those parameters, which it did.

Notwithstanding DEF's compliance with the operating guidelines, during a planned outage in the spring of 2012, after approximately three years of operation, damage was discovered on the last stage of blades in the low-pressure turbine. The last stage blades are also referred to as the L0 blades. You will hear both, and we have an actual representation of the blade over there on the side of the courtroom for you so you can see it.

THE COURT: Oh, okay. I walked right by it.

MR. BERNIER: So that's what we will be talking about today.

We also have a diagram that staff has provided of the operation and the actual steam turbine with CTs and everything that Mr. Swartz and maybe Mr. Polich will be referring to.

Now, DEF discovered the damage during an inspection as part of an unrelated outage and consulted with Mitsubishi, which recommended replacing the L0 blades on the turbine end of the steam turbine prior to restarting operations. The damaged blades were replaced and the operating parameters were also adjusted by Mitsubishi, resulting in the establishment for the first time of a new exhaust pressure limit on the intermediate pressure portion of the turbine.

Now, during of this second period of operation -- and you are going to hear us referring to different periods of operation, and those periods are shown on Mr. Swartz's Exhibit JS-2, it's No. 80 on the comprehensive exhibit list, and it's Duke Energy's root cause analysis. That breaks it down into the various periods you are going to hear us discuss throughout this hearing.

During the second period of operation, DEF complied with the modified operating parameters, but DEF wanted to return to the output from the machine that it was previously able to provide when operated to its original higher specifications. To be clear, beneficially extracting as much energy from the steam being produced by the combustion turbines benefits Duke Energy's customers.

Therefore, during Period 2, DEF contracted for new heavy-duty blades that would allow the machine to produce additional megawatts. When the unit was removed from service to install these new upgraded blades, damage was discovered on the Period 2 blades. So at the outset of Period 3, Mitsubishi installed temporary blade vibration monitoring to allow for telemetry testing to better understand what was happening with the blades.

As a result of that testing, for the first time, Mitsubishi created an avoidance zone, which is a combination of steam pressure and condenser pressures that should be avoided or minimized during stable operations, and that was communicated to Duke Energy around four months into Period 3.

Again, notwithstanding DEF's compliance with these new operating parameters, including avoiding operation in the newly-established avoidance zone, the new upgraded blades again suffered damage. For the first time, however, the damaged areas shifted from the mid-span snubbers, which I believe is right in the middle of the blade, and shifted out to what's called the Z-locks, which are at the end of the blade. And this led DEF to the conclusion that the modifications simply shifted rather than corrected the blade issues.

This Period 3 experience led to further blade modifications and reduced operating parameters in addition to the avoidance zone for the Period 4 operations.

Once again, although DEF complied with the reduction and operating pressures, knowing that those modifications to the operating specifications would result in reduced output for its customers, the Period 4 blades were also found to have damage after approximately five months of operation.

At this point, DEF determined the best course of action was to go back to the first iteration of blades, which, coupled with further reduction in steam pressure, was thought to provide the best chance of event-free operation while Duke Energy and Mitsubishi could more fully understand the cause of the damage. However, DEF's operators detected an indication of blade damage in these Period 5 blades after only approximately 1,500 hours of operation.

Again, the blades were damaged even though the unit was operated pursuant to the most conservative guidelines provided to date. Therefore, DEF determined the prudent intermediate path forward was to replace the last-stage blades altogether with pressure plates. These plates allow steam to pass through the turbine but do not rotate and, therefore, do not contribute to generating power resulting in a reduction in potential generating capacity. However, the pressure plates did allow for event-free operation for the benefit of Duke Energy's customers.

It's also important to remember that DEF was able to discover each instant of blade damage -- instance, excuse me -- before catastrophic failure could occur.

As this course of events was playing out, and in addition to cooperating with Mitsubishi on their various root cause analyses, which I think you will hear about today, DEF was engaged in performing a root cause analysis analyzing the information gleaned from each of the different incidents.

DEF's root cause analysis specifically considered six potential failure causes, three operational causes and three design causes.

Ultimately, DEF determined that none of the reviewed causes in isolation or in combination could explain the various blade episodes. Thus, DEF was left with one conclusion: The blades' lack of adequate design margin did not allow the blades to operate without incident at even the reduced operating pressures recommended by the equipment manufacturer.

Said differently, under normal operating conditions within Mitsubishi's operating guidelines, the blades were not designed to handle the pressures found within the low pressure turbine. DEF had no way of knowing this information. It prudently relied on Mitsubishi and operated the machine according to their instructions, as it would any other machine across its fleet.

Now, Public Counsel's witness, Mr. Polich, based on his review of documents, has determined that the cause of the failures is very simple. He believes that DEF ran the steam turbine too hard in the first period of operation. More specifically, Mr. Polich concluded that the operation of the steam turbine in a manner that produced over 420 megawatts caused the blade damage, and had the unit not been operated in this manner, the original blades would still be in the machine and operating today.

This conclusion is contradicted by the later episodes that occurred without reaching the operation levels Mr. Polich asserts caused the damage.

During his deposition, Mr. Polich candidly agreed that DEF operated the unit prudently in each period other than the first.

Of course, if DEF operated -- prudently operated the blades in those latter periods, as Mr. Polich agrees, and the blades still suffered damage, there must be a cause, and that cause is the lack of adequate design margin as DEF has concluded.

Now, not only does the later operating

experience and blade damage at lower operating pressures show that the original blade damage was not caused by operating in excess of 420 megawatts, Mr. Polich also admitted that he does not and cannot know at what point during Period 1 the original blades failed.

Because he cannot know when the original blades were damaged, it follows that he does not know how the steam turbine was being operated at the time the damage occurred, or whether the damage occurred when the unit was being operated above or below 420 megawatts of output.

Now, obviously this begs the question, how can he be so certain that it was simply operation above 420 megawatts that caused this damage?

Now, this is important, because under Mr. Polich's definition, operating below 420 megawatts was prudent. And if the damage occurred during prudent operation, the damage is certainly not DEF's fault.

And Mr. Swartz will testify that the Bartow plant was operated pursuant to industry standards and in line with the best interest of customers. The goal of plant operators is to maximize the output of generating units. This allows the utilities to avoid building additional generation or operating less cost-effective units to meet demand and, therefore, it saves customers money. Moreover, his testimony demonstrates that the steam turbine was at all times operated by the guidelines provided by Mitsubishi.

In short, DEF operated the steam turbine prudently from commissioning up until the February 2017 outage, and prudently installed pressure plates in place of the malfunctioning blades while a long-term solution could be devised, tested and implemented. Therefore, DEF should be permitted to recover its prudently incurred costs.

And I apologize for taking so long, that's more than I have ever said. Thank you.

THE COURT: I guess Office of Public Counsel goes next.

MR. DAVID: Yes, sir. Good morning, Judge Stevenson.

My name is Tad David with the Office of Public Counsel, and we represent the customers of Duke Energy Florida. We are here to establish facts, facts that we contend showed Duke Energy made foreseeable errors in the operation of its Bartow plant, errors that cost money, money that Duke

Energy now wants its customers to pay.

As you will see from the evidence, the sequence that links the customers to these errors is tenuous, but the link between Duke Energy's imprudent decisions and these errors is direct and proximate. Further, we will show that Duke initially concluded that the damage was caused by its operation of the plant.

As an investor-owned utility in Florida, Duke has a duty to make prudent and reasonable decisions in operating its generation facilities, and regarding any items that add cost for customers.

In this case, Duke had the resources and information that should have informed them of the proper operation of the Bartow plant. They knew or should have known that the way the Bartow plant was being operated was beyond the prudent operation of that plant. Through the exercise of due diligence and prudence, Duke should have understood that the output was entirely too good to be true. Their imprudent operation directly damaged this plant and cost money.

In this case, we are asking that the fuel clause recovery requested by Duke be reduced by an amount equal to the additional fuel cost caused by

Duke's imprudent operation of the plant, additional costs they are now trying to recover from customers. These costs should not be paid by Duke's customers.

No documentation exists that showed shows the manufacturer ever indicated that the steam turbine could generally be operated to produce an output above 420 megawatts during the initial period. The steam turbine was not designed to operate above 420 megawatts for any extended period of time. And the contract with Mitsubishi, who was manufacturer of the steam turbine, did not contemplate it operating above 420 megawatts of output.

For the period of July 2009 through February 2012, Duke operated the steam turbine above 420 megawatts for a total of 2,972 hours, including 2.4 hours above 450 megawatts, 1,555 hours above 440 megawatts and 2,302 hours above 430 megawatts.

As Mr. Bernier mentioned, in March of 2012, upon a routine inspection of the low pressure section of the steam turbine, Duke discovered that parts of the turbine were damaged. Since that time, for the past eight years, Duke has been trying to fix this steam turbine.

The evidence will show that the problems, and more importantly the costs at issue in this case cascade from Duke's operation of the Bartow plant in that initial period of operation from 2009 to 2012. This was Duke's fault.

The first evidence that Duke requested Mitsubishi consent to run the plant above 420 megawatts was in July of 2012, after the damage had been discovered in the first period.

The reply to this request was basically, hold on, you know, let's be careful. After the damage was discovered in March of 2012, the steam turbine never again consistently achieved 420 megawatts, except during very limited periods in a testing environment.

Later in 2012, Mitsubishi indicated that they could do an analysis of the circumstances that might allow the plant to produce -- to consistently produce 420 megawatts, but this analysis would cost $232,000 just to perform the analysis. There is no evidence that Duke commissioned Mitsubishi to perform this analysis.

In March 2018, Duke completed a root cause analysis of the problems experienced with the steam turbine at the Bartow plant. This root cause analysis was originally initiated to establish the cause of the damage discovered in -- during the first period beginning, you know, in March of 2012.

Drafts of this root cause analysis indicate that Duke engineers initially acknowledged that Duke contributed to the damage by introducing excessive steam pressure into the low pressure section of the steam turbine.

Over time, Duke's root cause analysis drafters softened the role that the excessive steam pressure played in the damage and focused instead on the blade design issues that followed the initial damage and failures.

We do not know the reason behind all the subsequent edits or revisions, however, you know, presumably not because the admitted information strengthens the argument that it was not -- the problems were not Duke's fault.

The evidence will show that no similar Mitsubishi steam turbines with the same blades has had blade damage or failures like that experienced at the Bartow plant.

Through Mr. Swartz's direct and rebuttal testimony, Duke will try to invert the cause and effect in this case. They will point to situations after they damaged the turbines to support the idea that similar but not identical situations did not damage the turbine during the initial period.

The evidence they will try to use, in fact, shows that Duke decided it was easier to ask for forgiveness than permission to increase the output from the steam turbine and that Duke imprudently operated the turbine in such a fashion that it was damaged, potentially irreparably damaged.

This case, as you have already heard, revolves around some technical subjects. We will discuss succinctly as possible how this particular type of power plant works; how the operation of the plant affects the components of the plant; and how the operation and the resulting breakdowns have increased the cost of operating the plant.

Lastly, we will explain why it is appropriate for only prudently and necessarily incurred fuel expenses to be recovered from ratepayers in the fuel clause.

We cannot forget, Duke bears the burden of proof in this case to establish its entitlement to the recovery of replacement power costs as prudently and necessarily incurred. We are certainly not here to suggest that Duke Energy or any of its employees are bad. The bottom line is that someone at Duke made errors, foreseeable errors that cost money, money that Duke Energy now wants its customer to pay.

We believe that you will see that Duke, not its customers, should be the one that bear these additional avoidable costs.

Thank you.

THE COURT: Thank you, Mr. David.

Next will be Mr. Moyle.

MR. MOYLE: Thank you, Your Honor.

Again, Jon Moyle for the Florida Industrial Power Users Group.

Your Honor, my client is comprised of a number of entities that use a lot of power 24/7, and the cost of power is important to them. A lot of them compete in markets not only in the United States, but internationally. I characterize them as folks in the pulp and paper business, the phosphate business, the chemical business, metal recycling. There is a wide variety of folks. I just wanted to share that with you to give you a little sense of why I am here and who I represent.

I think that, as noted, the burden of proof, obviously, is very important. I don't think there is a disagreement that Duke bears that burden. And they have a tough burden to overcome. As you heard, I don't think it's really in dispute that Duke operated this plant initially when they got it out of a warehouse in Japan.

They brought it over, it sat in a warehouse for, I think, a number of years in Japan. And when they brought it here, they ran it beyond its 420-megawatt capabilities. And I don't think you will hear disputes about that, that in terms its operation, it was beyond that.

So with that fact going in, I think they have a tough hill to climb to show, well, notwithstanding that, we still should recover the monies in dispute.

And I think it's also helpful for -- to put in context the monies in dispute here. These issues, as you know, are a couple of issues that in the fuel docket. And the fuel docket is an annual docket that the PSC opens. All of us are in it and participate in it.

And in the fuel docket, of which these two issues have been spun off for your consideration, Duke -- the Commission has already ordered that Duke recover, its a big number, 1.3 billion approximately -- for the record, 1,303,329,632 -- and that's in an order from the PSC. So what we are arguing about today is give or take approximately one percent of monies that have already been ordered to be recovered by the Commission.

And in terms of thinking about how to make the opening point with you, you are going to hear a lot of technical information today. But I think it's important to note that, you know, the ratepayers, I would draw an analogy of the ratepayers maybe to a homeowner who is going to get a new home built. And the homeowner contracts with knowledgeable people, an architect and a general contractor to build a home. And if a construction defect occurs, the homeowner is inclined to say, that's on you all, because I don't have expertise in this. I relied on you. And I think that ratepayers are in a similar position.

It's a regulatory compact. These are monopolies, but the ratepayers surely don't have the expertise in these areas. And what you have here is you have Duke kind of pointing the finger at Mitsubishi and saying, well, we think it's a design defect. And why do they say that? I mean, largely because largely because they can't identify the problem that occurred.

And Mitsubishi is saying, no, we think you overran the plant at the beginning, that you put too much steam through it, and you all caused the problem.

So there is a lot of uncertainty there. These are complicated machines. Overrunning it at the beginning, does that have a downstream effect that these turbine kept breaking?

What we do know is that the turbines continued to break and not be operational. And the result was is that they had to go out and get extra power, and that's what we are arguing about today.

But I think it's important that the customers, you know, not bear this risk. I don't think Duke can make -- prove the burden. And I am going to spend a little time asking about, well, how is it between Mitsubishi and Duke? I mean, shouldn't you all figure out who is responsible for this?

And I think you will hear a little bit from Duke's witness about, well, we really couldn't get them to assume risk because it's too great of a risk for going out and buying power and -- you know, but respectfully, we don't think that risk should fall on the ratepayers, particularly in this case, because we don't believe Duke can carry their burden of proof.

So thank you for the opportunity to share those thoughts with you.

THE COURT: All right. And PCS.

MR. BREW: Thank you, Judge Stevenson.

PCS Phosphate operates their phosphate mining operating in Hamilton County. It is by far one of the largest electric loads on the Duke Energy system, and so affordable power is crucial to their operations and fees, quote. That's why we are here.

You will find that everyone at these tables will agree that in its roughly 11-year history, the Bartow plant hasn't run as expected, that there are a series of events all involving the last level of blades, the L0 blades and the failures, and you will get a real education on that.

What we also agree on is that the manufacturer of the steam turbine, Mitsubishi, has no prior experience anywhere in the world with what has happened at Bartow; that Duke has no prior experience operating a combined cycle facility in the configuration of this plant.

And it's important to remember that when the steam turbine is running, it always runs at 3,600 RPM when it's connected to the grid. And so you are going to hear a lot about the five initial period that were studied in the root cause analysis. I just want to focus on the last one, which occurred in February 2017, where a fragment of one of the blades flew off at 3,600 RPM, which means that it was carrying a velocity roughly comparable to a speeding bullet through the turbine until it hit something and caused some damage.

And that's what we are talking about in terms of replacement fuel is the downtime while they initially decided how to repair from that damage, where the decision was to take all the blades out, all the zero level blades out and put in the pressure plate that Mr. Bernier talked about, which downgraded the unit, so it was -- it lost about 10 percent of its production capacity that consumers have had to deal with for almost three years now.

It's been our concern on rebuilding the record that we still don't know if the plant is fixed. We still don't know if the real root cause has been addressed; that Duke and Mitsubishi worked together when they finally decided to focus on vibration levels to do some actual telemetry testing for vibration, and they are now insisting that their vibration monitoring be part of the new fix.

So to our mind, Duke hasn't really established that it has still figured out how to repair the plant, but clearly the burden lies with them.

Thank you.

THE COURT: And the Commission.

MS. BROWNLESS: We will waive opening statements. Thank you.

THE COURT: I don't know whether you are here as a referee or what. Thank you.

MR. REHWINKEL: Your Honor --

THE COURT: Yes, sir.

MR. REHWINKEL: -- if I could interject. I have a housekeeping matter.

We have a copy of the documents we were required to bring today. Would you like me to give you those now?

THE COURT: Sure. That would be fine.

MR. REHWINKEL: Okay. And I also wanted to mention that we've identified exhibits. There are two additional exhibits that we have distributed to all the parties that I would just ask at this time -- oftentimes at the Commission, when we have cross-examination exhibits, we don't normally pre-identify them, but I have done that.

One of them is an exhibit that is excerpts from what would be Exhibits 102 and 103, and I have talked to counsel for the company about that. Everyone has it in the red folders that we've distributed, and I would just ask if I could get agreement that that would be admitted into the record under the same conditions that the other documents have and given a number?

MR. BERNIER: Which one was the excerpts from 102 and 103? Of this?

MR. REHWINKEL: It's in the first one. It's got the tabs on it.

THE COURT: So you are saying, Mr. Rehwinkel, you want these sort of pulled out and identified as a separate exhibit?

MR. REHWINKEL: Yes, Your Honor. They don't have a number at this time, but assuming that we have no objection to it, I think it would be given No. 115.

THE COURT: 115.

MR. REHWINKEL: It would be called draft -- RCA draft exhibit. And then there is one other one which would be 116, and it would be March 18, 2015, 40-inch blade telemetry. And that's the other envelope that says telemetry on it.

MR. BERNIER: So we have no objection to this being marked at this time. Based on the questions that are being asked, there may be objections at that point. I don't know yet, so I will withhold right to object at that time.

THE COURT: Okay. We will just identify them.

MR. BERNIER: Identify them for discussion.

THE COURT: Identify as 115 and 116.

(Whereupon, Exhibit Nos. 115 & 116 were marked for identification.)

MR. REHWINKEL: That way we won't have to do that then. I will give you your set.

MS. BROWNLESS: Excuse me, Charles, I just want to make sure I am doing this correctly. This RCA draft exhibit is 115?

MR. REHWINKEL: Yes.

MS. BROWNLESS: And what is 116?

MR. REHWINKEL: It's in the other pouch, and it's the last one. It's the last document. No, it's a skinny one.

MR. BERNIER: I have another question. Is there a copy for the witness when they are up there?

MR. REHWINKEL: I don't have one.

MS. BROWNLESS: What does it say on the outside, Charles?

MR. HERNANDEZ: It does not have an exhibit number on the top right-hand, so it's blank.

MS. BROWNLESS: I'm sorry.

MR. REHWINKEL: It has a cover on it.

MR. HERNANDEZ: That's it.

MS. BROWNLESS: Okay.

MR. REHWINKEL: Yeah.

MS. BROWNLESS: Thank you for being patient.

MR. REHWINKEL: I apologize for going off the schedule there, but I thought it would be better if we just got this taken care of.

THE COURT: That's fine. That's perfectly okay.

MR. REHWINKEL: Okay.

THE COURT: If there is no other preliminaries, I guess we are ready for Mr. Swartz.

MR. BERNIER: Thank you. Duke Energy calls Mr. Jeff Swartz.

THE COURT: Mr. Swartz. You have already offered testimony, but I will swear you in.

Raise your right hand.

Whereupon,

JEFF SWARTZ

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

THE WITNESS: I do.

THE COURT: Have a seat.

EXAMINATION

BY MR. BERNIER:

Q Mr. Swartz, could you please provide your name and job title for the record, please?

A Jeff Swartz. I am the Vice-President of Generation for Duke Energy Florida.

Q Thank you.

And on or about March 1st, 2019, did you cause to be filed direct testimony in the 2019 fuel docket before the Florida Public Service Commission?

A Yes, I did.

Q And do you have a copy of that testimony with you today?

A I do.

Q If I were to ask you the same questions here today, would your answers be the same?

A Yes.

MR. BERNIER: Judge, at this time, we would ask that Mr. Swartz's prefiled direct testimony, dated March 1, 2019, be entered into the record as though read.

THE COURT: Hearing no objections, we will show that done.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20190001-EI

MARCH 1, 2019

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

A. I am employed by Duke Energy Florida ("DEF" or the "Company") as Vice President – Generation.

Q. What are your responsibilities in that position?

A. As Vice President of DEF's Generation organization, my responsibilities include overall leadership and strategic direction of DEF's power generation fleet. My major duties and responsibilities include strategic and tactical planning to operate and maintain DEF's non-nuclear generation fleet; generation fleet project and additions recommendations; major maintenance programs; outage and project management; retirement of generation facilities; asset allocation; workforce planning and staffing; organizational alignment and design; continuous business improvements; retention and inclusion; succession planning; and oversight of hundreds of employees and hundreds of millions of dollars in assets and capital and operating budgets.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the United States Naval Academy in 1985. I have 17 years of power plant and production experience in various managerial and executive positions within Duke Energy managing Fossil Steam Operations, Combustion Turbine Operations and Nuclear Plant Operations. While at Duke Energy I have managed new unit projects from construction to operation, and I have extensive contract negotiation and management experience. My prior experience also includes nuclear engineering and operations experience in the United States Navy and project management, engineering, supervisory and management experience with a pulp, paper and chemical manufacturing company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with information related to the Bartow Steam Turbine (ST) forced outage that occurred from February 9, 2017 through April 8, 2017, including background information on the event that led to the outage, an explanation of DEF's responsive actions, a presentation of DEF's root cause analysis and findings, and an explanation of DEF's reasonable and prudent restoration actions.

Q. Please provide a summary of your testimony.

A. On February 9, 2017, the Bartow steam turbine was removed from service due to an indication of a sodium leak into the steam water cycle. During this shutdown, DEF discovered a failed LP turbine rupture disk. The disk had been breached by a foreign object that caused a hole in the rupture diaphragm. DEF performed an inspection of the Bartow Steam Turbine ("ST") and discovered damage to the ST's L-0 blades (and determined part of an L-0 blade ruptured the LP turbine rupture disk), resulting in a forced outage to the ST that lasted until April 8, 2017 (while the ST was off-line, the Bartow combustion turbines ("CTs") remained available to run in simple cycle mode). DEF performed a Root Cause Analysis ("RCA") that determined the failure of the Bartow ST's L-0 Blades was caused by events beyond DEF's control, and DEF could not have reasonably prevented the failure from occurring. The results of DEF's RCA were discussed in more detail in my March 1, 2018 testimony filed in Docket No. 20180001-EI, which I adopt and incorporate as if fully set forth herein. DEF's actions prior to and in the wake of the blade failure were reasonable and prudent.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the DEF RCA Report, attached as Exhibit No. __ (JS-1) to my March 1, 2018 testimony filed in Docket No. 20180001-EI.

Q: Is the RCA considered confidential by the Company?

A: Yes. Portions of the RCA's findings are considered proprietary and confidential by the blades' manufacturer. In order to protect the OEM's rights, this information has been treated by the Company as proprietary confidential business information and has not been made publicly available. As part of the stipulation reached on Issue 1B in Docket No. 20180001-EI, DEF committed to work with the OEM to revise the confidentiality request; DEF intends to fully comply with that stipulation.

Q. Please summarize the events leading up to the 2017 Bartow event.

A. Bartow is a 4x1 Combined Cycle ("CC") Station with a ST manufactured by Mitsubishi Hitachi Power Systems ("MHPS"). The ST was purchased from a company that intended to use it for a 3x1 CC with a gross output of 420MW. The ST was never delivered to that third party but instead remained with MHPS in a warehouse in Japan until DEF purchased the unit in 2006.

Before the ST was purchased, DEF contracted with MHPS to evaluate the ST design conditions and to update heat balances for a 4x1 CC configuration. CC units blend steam from the CTs as they start-up and/or shut-down with steam to the ST. These blending events result in brief periods of higher steam temperatures and flows into the condenser below the ST L-0 blades, a common occurrence for CC units.

Since commissioning of the Bartow ST in 2009, there have been five (5) events involving L-0 blade failures and/or replacements. The latest blade failure occurred when a "loss of mass" event resulted in a blade fragment traveling through the Low-Pressure Turbine rupture disk diaphragm.

Q. What actions did DEF take in response to the February 2017 failure?

A. The Company took three primary actions in the wake of the event: a root cause team was established to investigate the incident and prepare a root cause analysis; a restoration team was formed to bring the unit back on-line; and a team was formed to evaluate a long-term solution for Bartow.

Q. Please describe the process DEF followed to ascertain the root cause of the event.

A. DEF created a RCA Team consisting of internal experts to investigate and determine the root cause of the event. The RCA Team consisted of seven individuals with expertise in engineering, operations and process, and human performance.

Following industry standard procedures, the RCA Team employed specific tools used to determine potential root cause(s) including: interviews, event and causal factor review ("E&CF"), flawed barrier analysis, change analysis, component analysis, visual inspections of the equipment, photographs taken following the event, engineering calculations and measurements, and detailed review of outage reports and maintenance logs.

DEF's findings are fully set forth in the RCA identified as Exhibit No. __(JS-1) to my March 1, 2018 testimony in docket No. 20180001-EI and as summarized in my testimony of that date. To avoid unnecessary repetition, those findings will not be rehashed here.

Q. What restoration process did DEF follow to bring tl

service?

A. It's important to recall that the four Bartow CTs were able to continue operation in simple cycle mode (i.e., without operation of the ST) notwithstanding the blade failure. DEF worked with the OEM to identify and implement an interim solution that would allow the ST to resume operation, ultimately resulting in the installation of a pressure plate in place of the L-0 blades on March 22, 2017. The plate allows the ST to operate increasing the energy output of Bartow above what was possible in simple cycle mode. As mentioned above, the ST returned to service on April 8, 2017.

Q. Could DEF have reasonably prevented the event and the ensuing outage at Bartow?

A. No, the outage was caused by circumstances beyond DEF's reasonable control, as demonstrated by the RCA. DEF was not at fault.

Q. Did DEF act reasonably and prudently to restore Bartow to service in a timely fashion?

A. Yes, DEF took reasonable and prudent steps to develop a restoration team and guiding processes to restore the Bartow ST to service. The restoration team followed those processes and the unit was successfully brought back on line in a timely manner.

Q. Did DEF's agreement with the OEM include a provision obligating for the OEM to contribute funds towards replacement power costs in the event of an outage caused by the OEM's product?

A. No; to the contrary, the agreement specifically disclaimed any liability for consequential damages.

Q. In your experience, do DEF's agreements with OEMs usually include a similar disclaimer of liability?

A. Yes. In my experience OEMs are not willing to accept the risk of agreeing to pay consequential damages (such as replacement power costs) given the uncertain and potentially open-ended liability. To my knowledge, this is the case throughout the industry.

Q. Have you or anyone under your supervision engaged in negotiations with a vendor that was willing to accept consequential damages as part of a component part purchase order?

A. No, in DEF's experience, vendors do not offer to accept consequential damages as part of the terms and conditions of their agreements. Further, when DEF has indicated that such a provision would be a required part of the agreement, vendors have indicated they would withdraw rather than agree to those terms. DEF simply has not found such a provision to be commercially available.

Q. Does that conclude your testimony?

A. Yes.

BY MR. BERNIER:

Q Mr. Swartz, have you prepared a summary of your direct testimony?

A I have.

Q And could you provide that, please?

A Certainly.

Good morning, Judge Stevenson. Again, my name is Jeff Swartz. I am the Vice-President of Generation for Duke Energy Florida. I will say DEF in the future. That meanings I have overall responsibility for DEF's generation fleet.

My direct testimony provides background regarding the issues that have arisen over the past few years with the Bartow combined cycle plant steam turbine, an explanation of DEF's response to those issues, including a summary of DEF's actions to restore the unit to service as quickly as possible. And finally a presentation of DEF's root cause analysis.

In short, after analyzing data from each of the blade failures that I will discuss in a moment, DEF determined that the only causal factor that explains each failure, and accounts for the different conditions attended to each failure, is that the blades lack sufficient design margin to effectively operate in the Bartow steam turbine.

Bartow steam turbine was manufactured by Mitsubishi Hitachi Power Systems. The combined cycle was placed into service in the year 2009.

And briefly some background. A combined cycle power plant uses both gas and steam turbines together to produce electricity. Combustion of natural gas in the gas turbine turns a generator producing electricity, and the waste heat from the gas turbine is routed to a heat recovery steam generator, or HRSG, producing steam routed to a nearby steam turbine which generates extra power. It is coupled to a generator.

Combined cycle plants can be set up in multiple configurations and provide for great operational flexibility. The Bartow combined cycle is called a 4-on-1 plant, meaning there are four natural gas fired combustion turbines, four heat recovery steam generators which provide steam to the one steam turbine. It can operate in a 1-on-1 configuration, a 2-on-1, a 3-on-1, a 4-on-1; or, when necessary, the gas turbines can operate in what we call simple cycle mode to generate electricity when the steam turbine is off-line.

The steam turbine itself is made up of a high pressure/intermediate pressure section which is a combined section, and a low pressure section as well. Each has a series of blades that, as the steam passes through the blades in the turbine sections, it spins the blades which, in turn, spin the rotor. The rotor is connected to a generator, and the generator is what produces electricity.

At issue in this proceeding is the low pressure section, specifically the last stage of blades in the low pressure section. They are called the L0 blades. The low pressure turbine at Bartow is a dual-flow unit, meaning the steam is admitted in the middle of the turbine and then flows axially in opposite directions through rows of blade. So thus, there are two rows of L0 blades, one at each end of the machine.

And if I could, Your Honor, I think it if I could stand up at this point --

THE COURT: Sure.

THE WITNESS: -- and use some of these exhibits over here, it might be helpful. I think I am going to move of this out of the way so everybody can see.

First, this is a overall plant. This is the combined cycle plant. This is the gas turbine right here. The gas turbine can run on its own. Gas is admitted in the middle. The combustion process of gas and air, compressed air spins a rotor, spins blades, spins a rotor, turns this generator producing electricity.

In simple cycle mode, the exhaust gases from that combustion just flow up this stack to the atmosphere. The beauty of combined cycle operation is that we can take that energy that's in that heat and swing a damper and make the gases flow this way instead.

All this represents what's called the heat recovery steam generator. It's a boiler. There is water in tubes that heat, and these exhaust gases heat the water in the tubes, and then the water is turned into steam. That steam then is then reused in the turbine generator unit. It's admitted into the high pressure turbine, and then actually sent back to the heat recovery steam generator, reheated to get more energy into the steam. If you raise the temperature of the steam, it raises the energy level. It's then readmitted to the intermediate pressure turbine. But this is really one shaft with blades connected to it.

And then the exhaust from this intermediate pressure turbine goes to the low pressure turbine, and some steam from the heat recovery steam generator comes into the low pressure turbine into the middle, flows in both directions, and then is exhausted into a condenser.

This, again, is rotating the shaft. This is one common shaft that's bolted together here and bolted together here, and then the generator produces electricity.

And like I said, at issue in this proceeding is the last stage of blades in this low pressure turbine. So it would be right here and right here, the longest stage of blades. The blades get successively longer as the steam flows through the machine because the steam is losing energy as it travels through the machine. It's transferring energy to the blades making them rotate. The blades have to be bigger and longer in order for the lower energy steam to have any effect. So the longest blades are the L0 blades.

This is an actual L0 blade from the Bartow combined cycle low pressure turbine. There is -- you can see it's curved. This is the blade itself. It's very heavy. It's about 60 pounds. A big piece of metal.

The issue that we've had is that the mid-span, there is something called snubbers. And at the tip, there is something called Z-locks or a shroud. These blades aren't connected to one another during -- when the turbine is stationary. When the turbine starts spinning, and someone already said, it spins at great speed, 3600 revolutions per minute, so 60 cycles per second.

Think about that. It's spinning that rapidly, and this is just one of 64 blades on the low pressure turbine. So it's quite a large diameter machine at this stage of the turbine.

These blades, you wouldn't be able to see it, but they untwist a little bit, just a tiny bit, and it makes these mid-span snubbers and these Z-lock tips come together, which strengthens the whole machine.

You get a segment in the middle of the blade and a segment at the tip of the blade that helps strengthen the entire machine. If not for that, these blades would vibrate more and potentially crack from high cycle fatigue, and that would be very disastrous and catastrophic if a piece of the blade were to come loose.

What we've had happen four different times was a piece of either the snubber or a piece of this Z-lock tip, or pieces have come off, come apart. So when we talk about blade damage, it was limited to the Z-lock tips or the snubbers.

And I wanted to make that clear, because through proactive action, we were able to find that damage before the blade itself was damaged, which could have been much more catastrophic.

Thank you for allowing me to show that.

So since being placed into service, the steam turbine has experienced five separate L0 blade incidents. Importantly, each instance was discovered either, as I said, by proactive inspection or by installed monitoring equipment, and DEF was able to take appropriate action prior to any catastrophic damage to the turbine itself.

As we discuss the incidents and throughout these proceedings, you will hear reference to different periods of operation. Period 1 is the time from when the units were first commissioned in year 2009 until discovery of the first blade issue. Period 2 began when the damaged blades were replaced and the unit returned to service, and so on.

Each period was accompanied by blade modifications, with one notable exception I will discuss momentarily, as well as modified operating parameters provided by Mitsubishi.

Steam turbines are operated within the

guidelines provided by the manufacturer. Those guidelines are based on the manufacturer's calculations of permissible steam flows, pressures and temperatures. With one exception in Period 3, when new hardened blades were installed, each operating parameter modification lowered permissible pressures which resulted in a corresponding reduction in electrical output from the generator.

Notwithstanding DEF's adherence to these operating instructions, each period concluded with discovery of blade damage. Of particular importance to DEF's root cause analysis was the experience of Period 5. The lessons learned from that period have significant importance because the blades used during that time were of the same design as the original iteration, and L0 blade damage was discovered despite the unit being operated well below the originally provided operating parameters.

Therefore, DEF's operation of the unit was not the cause of the iterative blade damage. As mentioned earlier, after analyzing the available data from each of the operational periods, and taking note of the fact that blade damage continued to be discovered even after the operating pressures were curtailed, DEF determined that the ultimate causation had to be the blades' lack of sufficient design margin.

With the discovery of the blade damage at the end of Period 5, DEF determined that the most prudent means of returning the steam turbine to service while a long-term solution to the blade issues could be determined, designed and implemented was to replace the last stage blades with what are called pressure plates, as Mr. Bernier said.

It's important to remember that while the unit was off-line and the pressure plates were being installed, the four combustion turbines continued to operate in simple cycle mode and provide service to our customers.

For reference, a pressure plate is just what it sounds like, it's a non-rotating plate, as Mr. Bernier mentioned. Instead of a blade reducing the pressure and the energy of the steam before it goes into the condenser, there is holes drilled in the pressure plate which reduce the pressure so that the steam then doesn't damage the condenser. So it takes that work out of the steam without the benefit of making extra productive work, a product.

So the pressure plate does not use the steam passing through it to produce electricity and, therefore, there is a decrease in efficiency because the unit is not getting all the available energy of the steam passing through it.

However, the pressure plate allowed for the unit to return to service quickly and to operate event-free for the past two-and-a-half years.

Because DEF did not and could not know that the blades in question did not have the necessary design margin, and because DEF at all times operated the unit within the OEM's operating parameters, DEF's actions leading up to and in response to the February 2017 outage were prudent, and DEF should be permitted recovery of its prudently incurred replacement power costs.

I look forward to answering your questions. Thank you.

MR. BERNIER: Thank you, Judge. We will tender Mr. Swartz for cross-examination.

THE COURT: Is there an agreement as to order of cross? Public Counsel is first?

MR. REHWINKEL: Yes.

EXAMINATION

BY MR. REHWINKEL:

Q Good morning, Mr. Swartz.

A Good morning.

Q Can you tell me your full name, please?

A Jeffery Raymond Swartz.

Q Okay. And you are the Duke witness alone, who alone is here to provide whatever evidence you feel is most relevant to meet your burden to demonstrate that Duke acted prudently in operating the Bartow steam turbine; is that right?

A Yes, sir.

Q Would you also agree with me that JS-2 is the principal piece of evidence that Duke submits as your explanation of the cause of the failure of the various sets of blades at the unit?

A Yes.

Q And just for the record, JS-2 was the same as JS-1, it just has a different level of confidentiality, right?

A Correct.

Q The RCA -- can you agree with me that if I ask you about an RCA, it means a root cause analysis?

A Yes, that's correct.

Q Okay. And this RCA is the sum of the evidence that you contend proves that Duke acted prudently at all

times; is that right?

A Yes.

Q And, Mr. Swartz, isn't it also true that sometime after March of 2012, Duke began, at least informally, the process of determining a root cause of the problems that you identified after the March 2012 discovery of the blade damage?

A Yes, that's correct.

Q And am I correct in assuming that a root cause analysis is important to any utility as a way of understanding their operations for and understanding and apply lessons learned and improving processes for safety and efficiency purposes?

A Yes. Absolutely.

Q And that RCA process is part of the Duke culture?

A It is.

Q Would you agree with me, to be effective, the RCA process must be objective and honest and designed and executed to get to the truth, even if it's not a flattering view of how the company conducted operations?

A Yes.

Q Would you also agree with me that a true RCA should not be an advocacy document, that it --

A Could you ask that again, please?

Q Would you agree with me that a true RCA should not be an advocacy document that is biased in its scope or analysis?

A Correct. It should dig into the issues and understand the lessons learned so we can improve. That's the purpose.

Q Okay. The RCA should also not be designed to reach predetermined or confirmatory conclusions, should it?

A Correct.

Q Would you agree with me that the final RCA document that was ultimately prepared was at least in part done so with an eye toward making Duke's case to the Florida Public Service Commission that you believed you were not imprudent in the actions related to the blade failures and the need to buy replacement power?

MR. HERNANDEZ: Objection, compound.

THE WITNESS: The root cause --

THE COURT: Hang on.

THE WITNESS: Sorry.

THE COURT: Yeah, could you break it down? It was two questions there.

MR. REHWINKEL: Okay.

BY MR. REHWINKEL:

Q Would you agree that the RCA was produced, at

least in part, with an eye toward making your case to the Public Service Commission?

A I would not think about it that way. The root cause was truly to dig into what happened, what can we learn from that? How are we going to improve?

There are many -- not many, but there are times when we have root causes, or any causal analysis when there is a likelihood that there might be legal proceedings attached to it, and so we will make sure that we follow certain guidelines from an attorney-client privilege standpoint, which we did in this one because we thought that there could be, but it wasn't what you are suggesting. It was truly to get at the issues and learn.

Q Okay. So is it also true that the RCA is your final product of an inte -- well, let me ask you this: When I ask you about an RCA -- if I ask you about the RCA, or the Duke RCA, can you agree with me that we are talking about JS-2?

A Yes.

Q Okay. So is it true that the RCA is your final product of an iterative and continuous root cause analysis process that dates back to 2012?

A Yes, that's correct.

Q And can we also agree that if I ask you about

the September 22nd, 2017, Mitsubishi RCA, that I will specifically refer to that as Mitsubishi's RCA; you understand that?

A I understand.

Q Okay. And when I ask you -- or when I say Duke, can you agree with me that even though Duke's merger with Progress Energy occurred in July of 2012, that any relevant actions or inactions that transpired, or should have done so, under the control of Progress Energy Florida's management are the same as if those things happened or didn't under Duke's management control?

MR. HERNANDEZ: Objection, Judge, calls for a legal conclusion.

THE COURT: I will overrule. I mean, if you know.

THE WITNESS: Could you ask that again, please?

BY MR. REHWINKEL:

Q Let me ask it a different way.

Will you agree with me that Duke today, in this case, stands in the shoes of Progress Energy for all relevant actions that occurred related to this Bartow steam unit?

A Yes.

Q Can you tell me when you first had the responsibility of overseeing the Bartow plant?

A It was at the beginning of 2012, when I first actually assumed the position I am still currently in. So just about eight years ago. Prior to that, I wasn't directly involved with the operation of the Bartow site.

Q Okay. So when you said the beginning of 2012, you mean you were a Progress Energy employee?

A Yes, as a Progress Energy employee.

Q Okay. And tell me what your role was.

A In January of 2012, I became the vice -- we made some organizational changes at the beginning of 2012 while we were still Progress Energy in anticipation of the merger. So prior to that, I was in our nuclear generation group during the year 2011, but in anticipation of the merger closing, we did some reorganization, and I became the Vice-President of Generation for the Florida region --

Q Okay.

A -- the fossil generation and not nuclear.

Q Tell me when your first time was having a role or responsibility in the Bartow blade failure RCA process?

A When we first found the issues in the spring of 2012, and we needed to know what the causes were.

It's a significant issue. And so under my direction, we started what became a very long root cause because we kept learning more as each iteration of failure occurred.

Q Okay. Can we agree that when I make a reference to a period like 1, 2, 3, et cetera, that you understand them to be many as they are defined in the first two rows in Table A on page five of the Duke RCA?

A Yes.

Q Okay. So you were with Duke and had executive oversight over the plant during Period 1, is that right; during the very last few days of Period 1?

A That's correct.

Q Okay. And I think you just said so, but I want to make sure I understand. You were the person responsible for initiating the RCA process that we are talking about here today?

A That's correct.

Q Okay. And would that also mean that you were the person most responsible for assigning the employees to conduct the RCA process?

A I had an overview of that, and I could weigh in on the team makeup, yes.

Q Okay. Now, I think you said in -- before to me that for the RCA team that was -- for the RCA process

that was conducted after Period 5, you did assign the members of the team that responsibility with you, is that right?

A I didn't specifically assign the people. I could have modified the group. I had input into the team members. I don't remember specifically assigning the individuals.

Q Well, let me ask it this way: Isn't it true that the responsibility for assigning the members to the team --

A Yes, sir.

Q -- was yours?

A That's correct.

Q Okay. Was that true just after the March 2017 events, or all throughout this long RCA process?

A All throughout.

Q Okay. Now, I think in your testimony you mentioned a long-term solution team, is that right?

A Yes.

Q And it's fair to say the long-term solution team and the RCA team worked somewhat in concert through the process, at least since Period 5; is that right?

A That's correct.

Q And would you have had the responsibility of assigning the members to both the RCA and the long-term

solution team?

A Yes.

Q Okay. Throughout the RCA process, going back to 2012, would it be fair to say that you did review and provide edits to some of the drafts in the process?

A I know I reviewed some. I don't recall if I provided edits.

Q Okay. If I saw a draft that had the initials JRS on either a comment or an edit, you are the only JRS that would have been allowed to make edits to those documents; is that right?

A I don't know if I am the only one, but it's likely me, yes.

Q You didn't give me names of anybody in the root cause team that had the initials JRS, right?

A Not that I recall.

Q Okay. Would it be fair to say that even though the engineers that were primarily associated with the RCA worked for what you called Duke's central engineering, in this project, they had at least a dotted line responsibility to you in the RCA process in that you were the highest Florida Power generation executive in charge of the Bartow project?

A Yes, that's fair.

Q And you would agree with me that the draft

documents that were provided to the Public Counsel as a result of late filed Exhibits 4, 5 and 6 of your deposition constituted a part of the work product supporting the document that is JS-2?

A I am not sure I understand your question.

Q Okay. Let me break it down.

You are aware that you -- that as -- at your deposition in August 30th, the Public Counsel asked for -- in various ways, we asked for the draft documents that preceded the Duke RCA, is that right?

A Yes, sir.

Q Okay. Would you agree with me that those draft documents, and the documents that we received in Exhibits 4, 5 and 6 constitute, at least in part, the work product that supported the RCA that you finally produced?

A Yes.

MR. HERNANDEZ: Your Honor, could the witness see the documents?

THE COURT: It might be helpful.

Do you have a clear recollection of what he is referring to?

THE WITNESS: I don't. There were a lot of documents involved with the root cause, so I don't know that I have -- I know specifically.

THE COURT: It might be helpful to put those in front of him.

MR. REHWINKEL: Okay. I was asked to bring eight copies, and I have distributed all my eight copies, so I --

THE COURT: Let's see what I have up here.

MR. REHWINKEL: The documents I am referring to are exhibit -- what we identified as Exhibit 115.

MS. BROWNLESS: Charles, you can have --

COURT REPORTER: You can use mine.

MR. REHWINKEL: Okay. This will be the official copy.

BY MR. REHWINKEL:

Q If I may. So this is the summary of the synthesis.

A This one here is?

Q Yes, and then this is Exhibit 4, 5 and 6.

MR. BERNIER: And those are marked, okay, in our version?

MR. REHWINKEL: Yes.

And just for the record, Exhibit 115 is a culling of the root cause drafts that were taken from Exhibits 4, 5 and 6.

MR. BERNIER: Okay. Does he have 116 so we can mark that for him?

MR. REHWINKEL: Oh, yeah. It would be in here.

MR. BERNIER: It would be right here.

MR. REHWINKEL: Yeah, this is 116.

MR. BERNIER: That way you don't have to mark it later.

THE COURT: Let me see -- okay.

MR. BERNIER: Which ones should he be looking at?

BY MR. REHWINKEL:

Q Oh, I am sorry. I thought you were reviewing. Your counsel asked if you could look at the documents.

A Okay. So I have reviewed it. I am familiar with what you --

Q Okay. So the question -- I think you answered it, but given that the objection came in, if I could just make sure.

Those documents that you reviewed in Exhibits 102, 103, 104 and 115, with the understanding that 115 is culled from 102 and 103, would you agree that they constitute a part of the work product supporting the Duke RCA?

A I would.

Q Okay. Would you also agree with me that the

documents in those four exhibits, 102, 103, 104 and 115, were retained as a matter of company practice?

A I think that is our practice, yes.

Q Okay. Would you agree with me that an engineer named Jake, Jacob or Jake English was designated to be the primary author of the Duke RCA?

A I would.

Q Okay. Would you also agree with me that he was the primary custodian or keeper of the documents that supported the RCA?

A Yes, I would.

Q Okay. Now Mr. English, you would consider him also to have been the lead author of the RCA?

A Yes.

Q But that didn't mean that he made all the analytical decisions, is that correct?

A That's correct.

Q He would be sort of like the engineer with the pen, is that fair?

A Well, Mr. English is more than that. He is --

Q I don't mean he is the scribe. But he was the one that was -- well, I will withdraw the question.

He was not the one making all the decisions. He was contributing to it, but somebody had to keep the record; is that right?

A He was one of multiple contributors, but he is the one that was the main author.

Q Okay. Other engineers, including yourself, were contributors to the RCA, is that fair?

A Yes.

Q Is it also true that non-engineers, including attorneys, reviewed drafts at some point throughout the process?

A Yes.

Q And RCA -- the Duke RCA was the only RCA, final RCA report that was produced throughout this whole process, is that correct?

A It was the only Duke Energy product.

Q That's what I mean. It was -- on your side of the fence, it was the only product that Duke finalized in this -- I think you referred to it before as a big, long root cause analysis, is that right?

A Yes, that's accurate.

Q Okay. Do you have a copy of your JS-2 with you?

A I do.

Q And we can do this. I am going to ask you questions from Exhibit 115, and just -- I should clarify something about 115, if you don't mind, Your Honor.

There is a table of contents. And the first

document actually is JS-2, and then I have put Documents 2 through 18 in here, and I have extracted -- I have included a screen shot at the back of this exhibit of the Duke file names that we were provided electronically, and I have extracted -- they say Bartow RCA white paper, pretty much, but there are some distinguishing features such as the date of the file or the author of it on this; do you see that?

A I do.

Q But you would agree with me that -- I mean, JS-2 is not a draft, it is the final document?

A Yes.

Q And if I could ask you to look back at Document 18. And this handwriting up at the top of each document is mine. It's not Duke's.

Would you agree with me that February 6th, 2018 draft, it has a watermark of draft on it, but this document is, in all respects, identical to the final document; is that right?

A I would really have to do a page-by-page turn to determine that.

Q Okay. But would you accept my representation it is the same document? It's the same date.

A It is the same date. I see that. So it's likely the same document, yes.

Q Okay. So maybe the easiest thing to do would be just to ask questions about the RCA in this document, because I am going to attempt to ask you questions going back and forth between the final and some of the drafts.
So if I could take you to Document 1 -- and one other thing, if you don't mind, as we work through this. In the bottom right-hand page of this Exhibit 115, we have a Bates number OPCCR -- RCAEXH dash, and then have the numbers. And those numbers correspond on the table of contents to the documents.
The Bates numbers in the upper right-hand corner are Bates numbers that we gave the late filed Exhibits 4, 5 and 6 because they came to us un-Bates, do you understand that?
A I think so. Yes.
Q All right. We don't need worry about those numbers up there. I am only going to be asking you about Bates numbers on the lower right-hand.
A I understand.
Q Okay. All right. So back on my questions.
On page two of JS-2, is it fair to say that the second full paragraph, starting with the word "based" is the ultimate conclusion of this RCA?
A Yes, it is.
Q And if we look on page 15 of the RCA, that

paragraph is just repeated under the word conclusion, is that right?

A Yes, it is.

Q Would you mind reading that aloud for the record?

A Based on its observations and study, Duke has been and remains of the opinion that the root cause of the failures in the steam turbine L0 40-inch blades is the blade design, lack of blade design margin. That is to say, under expected operating conditions at Bartow's 4-on-1 combined cycle unit, the MHPS blades are substantially more fragile than similar 40-inch blades both in Duke's combined cycle fleet and elsewhere in the industry.

Q Throughout, when we see MHPS, that's Mitsubishi, right?

A Correct.

Q Okay.

A Mitsubishi Hitachi Power Systems.

THE COURT: And OEM in this context also means Mitsubishi, right?

THE WITNESS: It does. Original equipment manufacturer.

THE COURT: Okay.

BY MR. REHWINKEL:

Q So in this RCA document, with this conclusion, Duke lays all the blame on Mitsubishi and assigns none of the blame to itself for the way the legacy Progress organization operated the plant in the first period; is that right?

A I think it's very clear we believe that the lack of blade design and the lack of margin in the blades is the root cause of all the failures of the blades.

Q Okay. Now, we discussed the period naming convention a few minutes ago. Under that Period 1 would generally be from June of 2009 to March of 2012, is that right?

A Yes, sir. That's correct.

Q Okay.

A And there is an easy reference for that on page five --

Q Right.

A -- Table A.

Q Would it be most accurate to say that the beginning of commercial operation of the Bartow plant and the steam turbine was approximately June 1st, 2009?

A I don't know if it was June 1st, but I know it was the months of June.

Q Okay. And is it further true that the end of

Period 1 was actually February 28th at 2:00 a.m. in 2012?

A Subject to check, yes. That sounds like when we would start an outage. Typically, we start when customer demand is low, and it was a planned scheduled outage we started at nighttime.

Q So isn't it Duke's position today that the company did nothing wrong in the way it operated the steam turbine during the first period?

A It is.

Q Is it also true that you have effectively asserted that even if you somehow operated the plant improperly with excess steam flow and high back-end loading on new L0 blades that you only did so because you were just not aware that you were doing anything wrong?

A We operated according to the parameters provided by the original equipment manufacturer, so I'm are not sure -- it seemed like there was two different -- a statement and a question there.

MR. BERNIER: I am sorry, Charles, are you referencing anywhere in his testimony?

MR. REHWINKEL: I am asking about what his root cause analysis shows and doesn't show, so...

BY MR. REHWINKEL:

Q So does the conclusion that you just read from your RCA mean that Duke's position is that Duke did not operate the steam turbine improperly in Period 1 by introducing excessive steam flow in the low pressure turbine and imposing high back-end loading on the L0 blades, and thus, Duke's operation of the steam turbine was not and could not have been a root cause of the blade failures in Periods 1 through 5?

A It does.

Q Is another way of putting that that the RCA conclusion means that it is Duke's position that even if Duke did run the unit improperly in Period 1 by introducing excessive steam flow into the low pressure turbine and imposing high back-end loading on L0 blades that it did not know that it was doing so, and thus, any harm caused was not its fault?

A It's our position that we ran it in accordance with the operating parameters that were provided.

Q Well, isn't it true that Duke put excessive steam into the low pressure turbine during Period 1?

A It is not true.

Q Isn't it true that excessive steam and high back-end loading on L0 blades caused damage to those blades?

MR. HERNANDEZ: Objection, Judge. I am

objecting on the basis of vague. I don't know what excessive means.

THE COURT: Maybe we should be more specific.

MR. REHWINKEL: Okay.

BY MR. REHWINKEL:

Q Well, in the root cause analysis process, didn't Duke engineers decide -- agree that excessive steam flow was introduced into the low pressure turbine?

A Could you point that out to me?

Q Okay. Do you have exhibit -- okay, let's go to -- let's just look at -- let's just look -- if you could turn to page 75, which is Exhibit 9.

A In Tab 9 in Exhibit 115?

Q I apologize. Yeah. Tab 9, yes.

A And I am sorry, could you say the page again?

Q 75.

A Okay, I am there.

Q And would you agree with me that the file name for this document is October 5, 2017, and it says PBC comments? That will be Paul Crimi, C-R-I-M-I?

A Yes.

Q And if you look halfway down the page, it says -- would you agree with me that it says: After months of study, Duke Engineering believes the following to be the most significant contributing factors towards

root cause of the history of Bartow Unit 4S L0 events, and the first put bullet is low pressure LP turbine excessive steam flow?

A Yes, I see that.

Q Okay. So the Duke Engineering folks that were drafting these documents accepted at this point in time that there was excessive steam flow introduced in the low pressure turbine, isn't that correct?

A I do not believe that to be the case, no. This is a working document that these are -- this is a list of bullet points of things that could have caused the root cause, things that needed to be investigated or analyzed more.

So low pressure turbine excessive steam flow is one of multiple items. Thermal distress at the LP turbine exhaust. Pressure pulses during hood or curtain spray operations. Shroud fretting fatigue found through zone analysis. Loss of dampening, blade fitment, those are all potential causes.

In fact, it looks to me like the team was zeroing in on the more likely causes that needed more analysis, but this is not a final document, so I would not agree with your statement.

Q Well, Duke Engineering wrote this statement, that's correct, isn't it?

A It is.

Q And Duke Engineering used the term "excessive steam flow", right?

A They did use that term.

Q Okay. So they had an idea that there was too much steam being introduced into the low pressure turbine, right?

A I think they had an idea that that could have been -- that is a potential cause.

Q Okay.

A That -- to be really clear, Mitsubishi's conclusion at that point in time was that there was excessive steam flow to the low pressure turbine. That fact that Mitsubishi believed that couldn't be ignored, and so that was investigated and analyzed very significantly throughout the course of the long root cause. Ultimately, it's not the root cause.

Q Just turn over a couple of pages to page 77 within this same document. Well, let me withdraw that question and let me take you -- well, let me ask you this: Mitsubishi said that you were putting too much steam in the low pressure turbine in Period 1, right?

A Correct.

Q Okay. Is high back-end loading, is that the same as excessive steam flow?

A They are related, I would say. If you can picture the steam pipe going into the center of the low pressure turbine on the diagram, if there is too much steam flow going in the middle of the machine, and then it goes axially in both directions, that could lead to high loading throughout the machine, including the back end, which would be the L0 blades.

Q Okay. And when you talk about high back-end loading here, just to be clear, you are talking about the loading on the blades, not loading on the condenser; is that right --

A Correct.

Q -- the way it's being discussed here?

A That's correct.

Q Can you show me in the RCA where you affirmatively determine that the introduction of excessive steam flow into the low pressure turbine and resulted in the position of high back-end loading on L0 blades in Period 1 did not occur?

A I don't know that I can show you that in the root cause. I think the root cause document -- well, what I know is the root cause document examines likely causes, potential factors operationally and from a design standpoint, and essentially rules each one of them out, concluding that the blades were not designed with an adequate margin for the application at the Bartow.

The root cause document, if we wrote in there everything that was not found, it would be an extremely long document, so I don't think I can point to what you just stated.

Q Well, you said that Mitsubishi said you put too much steam into the low pressure turbine, right, excessive steam?

A Yes, let me make sure, from a technical standpoint it's the pounds per hour per surface area on the blade that Mitsubishi was concerned about on the L0 blades. The units -- the engineering units are pounds per hour per square foot. And if you put -- you can calculate that number. It's not a measured number. But it's related to steam flow, but it has to do with the impact on the blade for steam flow on a certain surface area of the blade.

That was Mitsubishi's concern when we first had the issue. In fact, for quite some time, it was their concern, because the calculated pounds per hour per square foot of steam flow impinging on the L0 blades was higher than what their experience was. It wasn't higher than any limit. It wasn't exceeding any pressure limit. It wasn't exceeding any temperature limit. It wasn't exceeding any flow limit. It was higher than their experience, and that made them concerned. And so they concluded that there was too much steam flow that caused that higher loading on the back-end blade.

Q Well, specifically Mitsubishi said that running the unit above 420 caused excessive steam to impact the L0 blades, and that caused damage, isn't that correct? That's exactly what they said.

A Not really. The -- there is something we really need to talk about here.

So the 420 megawatts is the product of the generator. And as we have discussed, the electrical generator is coupled to the steam turbine. When you talk about a steam turbine, you talk about parameters like pressures, flows, temperatures.

The steam turbine is what is then spinning the rotor. The rotor is connected to the generator. The generator produces megawatts, or more precisely kilovolt-amperes, which then, in order to talk about the entire unit, it's very common in the industry. We produce megawatts. We produce kilovolt-amperes. So it's common throughout industry to talk in terms of the product that you are making to get a relative feel of the size of the unit.

So many times, people talk about sizes of combined cycle plants by the amount that the generator can produce. The amount that the generator can produce is dependent on many factors that are separate, actually. There is many factors that are part of the steam turbine output, but there is other factors that are in play as far as what a generator could produce.

So there is really -- in technical terms, Mitsubishi wasn't saying you exceeded 420, that was it. It was always all about the pounds per hour per square foot of steam flow impinging that last stage blade.

Q Do you have a copy of Exhibit 116 in front of you?

A I know I do somewhere. Yes, I do.

Q Okay. And this is -- are you familiar with this document?

A Yes.

Q Okay. And it's dated March 18, 2015, and it says, Duke Energy Bartow Report of Telemetry Test for 40-inch L0, right?

A Correct.

Q And if we turn to slide No. 4. This is what Mitsubishi says in the last bullet point: Mitsubishi estimated the cause of cracking was overloading of LP section based on 450-megawatt operation, which is over the design point of 420 megawatts, correct?

A Yes, that's what it says.

Q And that's what Mitsubishi said pretty much consistently throughout with respect to Period 1, right?

A They did. They were technical discussions, and I can point to other documents where they really talked about the steam flow, in particular the steam flow per surface area impacting the last stage blade. The use of the 420 here is just really a proxy for that steam flow.

Q Okay. But this phenomenon that I just read in that bullet point is what you mentioned that Mitsubishi said was going on, that that's why the Duke engineers put it in their RCA drafts before the final result was -- the final document was produced; is that correct?

A I am sorry, I am not sure what you are asking.

Q All right. Let me ask it this way: Because Mitsubishi said what I just read in that bullet on page four of Exhibit 116, that's the reason why that item is in the document that we looked at?

A Right. I see what you are saying.

So more correctly, I would say because Mitsubishi was talking about the steam flow that I have been stating was an issue, that's why we looked at it in the root cause.

Q Okay. So it wasn't just something off the

street that you had to deal with that would have made the document long. This was a significant central contention of Mitsubishi, correct?

A Correct.

Q This being the excessive steam flow and loading on the blades.

A At this point in time. Remember, this is without Period 3, 4 and 5 information available.

Q All right. But a document that was drafted in October 2017 would have been after Period 5, right?

A Yes.

Q Okay. So I guess what I am asking is you didn't affirmatively study the issue of high back-end loading on the L0 blades and reach a conclusion on that. Instead, you found that you couldn't study it, so you removed it from the final RCA, is that fair?

A I don't know if that -- I don't know all the details of every single thing that the root cause team studied or didn't study, so I don't know the answer to that question.

Q Well, let's look, if you will, on page one of the RCA.

Would you read for me the last full paragraph, because I want to ask your understanding of what that means?

A Starting with, Duke also studied?

Q I am sorry, starting with the second to the last paragraph.

A Duke Engineering?

Q Yes.

A Duke Engineering concluded that there was no correlation between any one of the above-listed factors in the five failure periods. Notably, Duke was only able to study each factor independently based on available data. In the absence of one, blade telemetry, two, duplication of the factors in various combinations, and three, operation in varying but normal conditions, it is not possible to study how each factor relates to and interacts with any other factor, if at all.

Q So doesn't that say that with respect to the early contentions that were even included in Duke Engineering's drafts about excessive steam flow and high back-end loading on the L0 blades, that you were unable to study it, and thus, you could not make a correlation and include it as an RCA conclusion; is that right?

A I don't believe that's what that is saying at all, actually. I think what this is saying is the root cause analysis is looking at things that happened in hindsight. If you had the ability to vary some variables and keep some others constant and do repetitive testing, you would be able to test out whether conclusions were valid or invalid.

Obviously, we couldn't do that. We are looking at data. We are looking at combinations of variables at specific points in time without the ability to change those. And that's what this paragraph is saying.

Q Well, let's go back to Document 9. It was written down in this document, and would you agree with me -- and we can go through many of these documents and see that this language, after months of study Duke Engineering believes --

A I am sorry, which page are you on?

Q I apologize. I am back on page 75.

A 75. Okay, thank you.

Q This -- after months of student, Duke Engineering believes the following to be the most significant contributing factors towards root cause of the history of Bartow Unit 4S L0 event. That language is replete throughout these drafts, would you agree with that?

A I would have to look at all the drafts.

Q Okay. So let's turn to page 123, which is Document 13, and we see halfway down the page there, same -- with the same bullet point, low pressure LP

turbine excessive steam flow?

A I do.

Q And then we could go to -- and that was dated October 12th, 2017, and you accept my representation that that's what the file name said?

A I do.

Q Okay. And then we see on 137, which is -- this is a document that appears to be dated the same day, but it has a different set of initials, BWM, is that Ben Meissner?

A Likely it is Ben Meissner, yes.

Q He is your Charlotte-based steam turbine expert, right?

A He is one of our subject-matter experts, right.

Q Now, this document purports to be his edits to the RCA draft, right, if the file name is correct?

A That's what it appears to be, yes.

Q And this has the same -- I mean, there are some edits here, but there is no edits to this -- this thing we are talking about, this comparable sentence, right?

A That's correct.

Q And then we go to Document 15, it's just dated 10/13/17. It doesn't identify who, but there is no --

the words are the same here, right?

A They are.

Q Okay. And then if we go to Document 16, this is dated 10/17/2017, we see the same verbiage, right?

A I am sorry, which page?

Q I apologize, page 165. This is Document 16.

A I seem to be missing that page from my copy. That tab 16 starts, unfortunately, with page 167.

MR. BERNIER: I will show him mine, Charles.

THE COURT: I'll check mine. To cut to the chase, this is 165.

THE WITNESS: Yes, it says the same thing.

MR. REHWINKEL: Okay. Thank you.

THE WITNESS: Thank you, Your Honor.

BY MR. REHWINKEL:

Q All right. And then we have a differently styled, but on Tab 17 at 179, we see the same language; is that right?

A Yes.

Q Now, if you turn over to Tab 18, this is the RCA draft that we agree that, in all likelihood, is identical to the final, right?

A Yes.

Q That sentence, that phrase falls out. It's not in the corresponding portion of the RCA; is that

right?

A That's correct.

Q Okay. So between October 2017, assuming this file date is correct, and February 6, 2018, we have no draft documents, but that falls out -- that meaning the statement that Duke Engineering believes the following to be the most significant contributing factors toward blade failure, et cetera, that concept is not in the filing document; is that right?

A It is. I think you are making an assumption that each of these documents you are referring to are drafts of the final root cause, and I don't believe that to be the case. Now, I don't know -- again, I don't know all the details of what the root cause team was doing during the long period of time they were working, but if you examine what you are showing here in all of these Tabs 9 through 17 and compare it to 18, there are many differences between all those working documents and the final root cause analysis, and you just happen to be pointing to one of many, many differences between working copies and the final root cause document.

Q Okay. Well, let's look at page 188, which is in Document 17, and this -- it says Appendix A, Bartow L0 Event Summary, right?

A It does.

Q Now, in the root cause, it's called Table A, on page five, right?

A It looks to be very similar to, if not identical, to Table A, yes.

Q Right. They are not identical.

A Okay.

Q This table -- Appendix A and Table A appear to be -- have common genealogy in this process, right?

A Yes.

Q All right. So I don't understand now your assertion that documents 2 through 17 are not drafts of the final RCA?

A I -- what I am saying is I don't know if they are or not, but to me, it does not appear that they are. There are so many differences between 2 through 17. And then when you compare it to how the root cause on Tab 18 reads, there are many, many differences.

I would classify all these documents as working papers that summarize what the root cause team is doing; what they are finding; what they are analyzing, but it's not a draft of the root cause, in my opinion.

Q Well, let's go back to Document 3, and it's dated -- it's on page 23.

A Okay.

Q It's dated June 26th, 2017, do you see that?
A I do.
Q Now, if you turn to page 25, we see a comment by JRS1, is that you?
A It is me.
Q Okay. So it would be fair to assume that you reviewed this document?
A Yes, sir. That's correct.
Q I mean, you wouldn't just review this one little paragraph here. You would have read the whole thing, right?
A That's right.
Q Okay. So this indicates -- and if we go to page 27, we see an early version of Appendix A, right?
A I see that.
Q Okay. Now, is it your testimony here today in court that this is not part of the process that developed the RCA?
A No, it absolutely is part of the process.
Q Okay. So let's go over to Document 6 now. I have included Document 6 in here because there on page 49 to 58, there were some stray documents that were in the file that was submitted, and I want to ask you if you are familiar with or recognize the document on page 49?

A I am familiar with the information. I don't know -- I can't say whether I saw this document before or not.

Q Is it fair to say that this document is sort of a template for how to put together the root cause analysis that you are going to be producing through this technical paper process?

A I really -- again, I don't know the details of how the root cause team decided they would gather information and make a final report. I can read it and tell you what I think if you can give me a minute, but I really don't know.

Q Well, if we look at -- let's just look, if we can, the top line says Bartow 4S root cause analysis and evaluation of contributing factors, right?

A Yes, it does.

Q That's kind of what you would do if you were going to get a root cause analysis process under way, right?

A It is. It's also something -- notes of the team, things that they need to analyze and investigate, absolutely.

Q Okay. And it says a little bit down there, brief history, copy/paste and add to what Ben wrote in his summary to Jeff Swartz/Tony Salvarezza, 3/29, right?

A Yes.

Q So this is -- this -- Ben, again, is probably Ben Meissner?

A Yes, I agree.

Q All right. And he wrote you a memo, I guess on March 29, we don't have it, but obviously there was something that probably explained what had happened from the steam turbine expert's point of view?

MR. HERNANDEZ: Objection, Your Honor, calls for speculation.

THE COURT: To the extent you know, Mr. Swartz, I mean, you can explain.

THE WITNESS: Yes, Your Honor.

I don't remember specifically what Ben Meissner wrote, but it appears he wrote some -- an email, a note, something pertaining to the steam turbine, yes. It's not surprising. He is one of our technical experts.

BY MR. REHWINKEL:

Q Right. So I don't know, and I can't represent to you that the next page, which is 51, which is a one-page document, that's dated 8/24/2017, is related or not to this document. Would you know? This document being page 49.

A If 51 is related to 49, is that what you are asking?

Q Yeah, I don't know if it is. I'm telling you I put together stray documents that were in the same area of the file.

A It appears to me that page 51 is actually some notes from a meeting, a working meeting. And I do agree with you that on 49, it looks like they are starting to put together things that would go into how you might want to format a root cause so that it would be clear and understandable.

Q Okay. So going back to page 49, it says: LP turbine back-end loading greater than 15,000 -- I forget how to say that.

A Pounds per hour per square foot.

Q Okay. And does this talk about how this has had an effect or not on the unit across the different periods of operation, right?

A That's what it says, yes.

Q So it would be reasonable to assume these documents that were maintained by the company, that there was an instruction to evaluate this as a part of the root cause process, right?

A Well, it looks to me like they were starting to build what would be in a final report out. And at that section, it appears that they were planning on having some statement on that subject.

Q Okay.

MR. BERNIER: Charles, I am sorry, could I ask you what the first word before draft is up at the top?

MR. REHWINKEL: It says "miscellaneous".

MR. BERNIER: Oh, thanks.

MR. REHWINKEL: I am sorry.

MR. BERNIER: That's okay.

MR. REHWINKEL: I think I had brackets around it.

THE COURT: Would this be a good time to take five?

MR. REHWINKEL: Yes.

THE COURT: We have been at it for a while and give Mr. Swartz and everybody else a stretch.

(Brief recess.)

THE COURT: I think we can resume, Mr. Rehwinkel.

MR. REHWINKEL: Thank you.

MR. BREW: Excuse me, Your Honor, before we start, just to save time, I circulated copies of the two exhibits that we may eventually get to. All the parties should have it.

THE COURT: Okay. Very good. I have it.

MR. BREW: And there is copies on the desk for the witness when he gets to it.

COMMISSIONER GRAHAM: Thank you.

MS. BROWNLESS: Excuse me, Mr. Brew. I don't see any exhibits. Oh, got it. Thank you, sir.

THE COURT: All these red folders, they all look alike.

MS. BROWNLESS: Yeah.

BY MR. REHWINKEL:

Q So, Mr. Swartz, are you saying that Duke did study the impact of high back-end loading on the L0 blades, or did you say because of what happened with the blade failures in Periods 3, 4 and 5, you didn't study it, you just took it out of the RCA?

A Well, I don't think I am saying either of those things. The loading is a calculated value. It's really based on Mitsubishi's experience with their fleet, and it's a parameter that Mitsubishi just uses to help look at what is the forces -- what are the forces on a turbine blade.

You know, as far as studying that, again, with hindsight, you can only look at what happened. You can't run experiments to try to determine if you run a certain amount of steam flow, you will get a certain response. In fact, you may not want to run that. So, you know, I don't think it's either of the choices you gave me.

Q Well, did you study whether the introduction of excessive steam flow into the low pressure turbine and the resulting imposition of high back-end loading on the L0 blades was not a significant contributing factor to the root cause of the L0 blade failures?

A I believe that was considered as -- I mean, it's obvious in all these documents that the root cause team considered that as a potential cause. The steam flow -- what's the exact wording? Let me read it exactly here. Excessive steam flow.

The turbine parameters, the operating parameters are pressures and temperatures. And pressures really are what dictate the flow.

What we are saying is that we did operate in accordance with the design pressures of the unit. Mitsubishi is saying that they are not disputing that, actually. What Mitsubishi is saying is that operating at those pressures ends up having a higher pounds per hour per foot square of loading on the back end on the L0 blade than what they are used to, and that that's unknown to them. It's uncertain.

In fact, there is certain documents. In fact, if you look at RAP-6, and even in Mr. Pollock's exhibit attached to his testimony, it talks about how Mitsubishi is just uncertain of what will happen in that zone.

So it's not known. I think that actually lends credence to the fact that the lack of blade design margin is the root cause. It's uncertain. The margin is not built in, and when you look at what happened over each successive period of time, even with lower operating pressures -- and again, the pressures are what dictates the flow through the turbine. Higher pressure, you are going to get more flow through the turbine.

As we went from Period 1 through Period 5, it wasn't successively lower, because Period 3 we actually raised the pressure at first in order to do some testing. But then during that testing, we realized we had something called an avoidance zone and we had -- which we had to avoid during operation, but we put specific pressure limits in place to make sure that we didn't have vibration on the last stage blades.

And that's really the issue. Whether it's steam flow, whether it's hardening on blade -- on the snubber or the tip, the shroud; whether it's blade fitment. It may be too loose. That means that there is not enough -- there is too much tolerance, perhaps, between the snubbers and the Z-locks. All those things lead to vibration or flutter in the blades, which then could cause a failure. And that's what we are trying to avoid. In fact, we did avoid that.

Again, I can't emphasize this enough. We found proactively four times that there were issues with the snubbers and with the Z-locks, and we were able to take the unit out of service, continue operating for our customers with the combustion turbine generators, but we took the unit out of service before that damage migrated into the blade itself, which that would have been a catastrophic failure that could have taken months or years, and many, many millions of dollars to fix. But we were able to avoid that because we found these issues proactively.

So, again, the steam flow is just one of a number of things that can cause vibration in a blade. And ultimately, the root cause is that there is not enough design margin in the blades to prevent that vibration from happening. Even Mitsubishi agrees with that in their later root cause, that the root cause in every period is too much vibration.

Now -- so that's -- that's what I think this is saying.

Q Mitsubishi doesn't agree that they designed a blade that caused a vibration in every period, do they?

A I am sorry, could you ask that again?

Q Mitsubishi doesn't agree that they had an inadequately designed blade that caused the vibration, do they?

A They are in agreement that high -- that flutter, vibration, was the cause of blade failures in each of the five periods.

Now, I think it's a debate whether or not the blade should have put up with the atmosphere at Bartow, the operating conditions at Bartow, pressures and temperatures, and able to vibrate without having damage or, you know, obviously they vibrated and had damage. I don't think Mitsubishi would ever admit to a design weakness.

Q Okay. I just wanted to make it clear, they didn't admit that they have an inadequate design, right?

A Correct.

Q Just along that line, the blades in Period 5, they are called Type 1 blades, right?

A Correct.

Q Were they identical to the blades in Period 1?

A There was one slight difference. They were -- so let's talk about type for a minute. The type of the blade is the, by far the most important thing. And could I -- could I stand up, Your Honor, again?

THE COURT: Sure.

THE WITNESS: So again, we have some other folks in here, too, but the type of the blade is the curvature of the blade, and it's really talking about this blade itself, which is the structure you are trying to protect. You don't want that to come apart. You don't want it to crack. All of our issues were either with this snubber at the mid-span, or with this shroud at the tip.

But Type 1 blades have a certain geometry of the blade and a certain manufacturer. Type 3 blades are different. I don't know the specific -- I am not a turbine engineer, but the curvature is different. The thickness might be different. It's a different style of blade.

When we went back to Type 1 blades at the end in Period 5, it's the exact same blade. It's the same snubber, and it's the same Z-lock with one small change. There was a change in the geometry, just a softening of the edges, so to speak, to prevent some potential stress riser spots on the Z-lock and on the snubber. And that was the only difference.

Both Mitsubishi and Duke Energy concluded that based on all of the different data that they saw from other periods, that those small geometry changes would be helpful to prevent future failures of either the shroud, the Z-locks or the snubbers.

BY MR. REHWINKEL:

Q The snubber was in exactly the same spot on the Period 5 blade as in Period 1?

A Yes, it was.

Q Do you know whether the manufacturing was exactly the same from the Period 1 blades that were made sometime before 2008 and the Period 5 blades that were made in 2012?

A Well, when you say the manufacturing, what do you -- how do you define that?

Q Well, how they are made, who they were made by, and the materials in them, were they exactly the same?

A I know the materials are exactly the same. I know that they are Mitsubishi blades, so we are really relying on Mitsubishi. They are a certain definition. They are Type 1 blades, so for what I know, yes, they are the same blades.

Q But you don't have any personal knowledge that they were -- that the manufacturing process was exactly the same, do you?

A Not any personal knowledge, no.

Q Okay. And did you have any evidence that they

were exactly the same? Did you go back and compare the manufacturing process in Period 1 blades and Period 5 blades?

A Not to my knowledge.

Q Okay. When -- at any point during this L0 blade event process, did Duke ever change any of the components in the low pressure turbine other than the L0 blades?

A Not to my knowledge, no. It wouldn't be surprising -- I mean, when you say any. There's many components inside a steam turbine, and every time you open it up, there is probably some sort of sealing surface that has to be changed. So I don't want to be wrong on a technicality, but -- actually, Mr. Bernier has a picture that might be really valuable if I could show it.

Q Sure. Just to be clear, I am not asking you about whether there was any ordinary maintenance that you did that affected any other component. My question was, and I think you understood it this way, did you make any other changes inside the L -- inside the low pressure turbine as a result of what you found in any of those damage events?

MR. HERNANDEZ: May I approach, Your Honor?

THE COURT: Yes.

BY MR. REHWINKEL:

Q Do you understand that?

A I do. And to answer, we did not make any others changes, and I think I can explain.

So this is the actual low pressure turbine at Bartow. Again, the steam goes in the middle and travels axially in both directions. You can see the blades get bigger as the steam travels through the turbine because the steam is losing energy and it needs more surface area to spin the turbine.

What you can't see in this picture is that there is fixed blades, called diaphragms, that fit in between each of these rows. So when you encase the turbine, those diaphragms are fitting in between. So as the steam travels through these nozzles, or blades, to spin the turbine, the diaphragms then redirect the steam so that they impinge on just the right angle to get the most work out of these blades as they travel through.

So they work in the second stage. Then they are redirected through diaphragms here, and then again redirected through the third stage. They are redirected into fixed blades here and redirected into the L0 stage.

And I think it's pretty important to understand that each iteration we had, we were able to inspect this whole turbine, and there were no other issues with the turbine. There were no other issues with the diaphragms. It was only with the L0 blades. And it wasn't with the blade itself, it was with the snubbers and the tips. And we took the blades out of service before there was damage to the blade, which would be much more significant and could cause damage to the whole turbine if an L0 blade failed.

It's such a massive weight going at such a high speed, that if a blade itself failed, it would be catastrophic, and that's what we were trying to prevent, and we did prevent through this process.

I think that's good for now.

Q So beyond inspection, you didn't do any study that determined that the upstream blades, or the nozzles or any other components in the low pressure turbine were unaffected by the pressures that were imposed in Period 1?

A Oh, I would say we have a great deal of information from these iterative inspections we did. You know, it's unfortunate that we had do so many inspections. The regular maintenance interval on a turbine would be maybe 100,000 operating hours, or 80,000 operating hours. It would be measured in years before you actually open up the casing of a turbine and look at it.

Because we proactively worked to prevent a blade failure, we had opportunity to look at the whole low pressure turbine multiple times over five years. Every time you open up a turbine, turbine engineers were all looking at it, taking measurements, doing nondestructive examination, making sure we don't have any other issues.

It was a concern. If we had issues in the last stage of blade, maybe there is issues in other stages, and so we did extensive examination, but we did not find any issues with any other stages or rows of blades.

Q And you didn't put that in the RCA, because you didn't feel that needed to be in there, that you determined that the rest of the turbine was fine?

A I am not sure why we didn't decide to put that piece of information in, but it's very clear we had so many opportunity for that inspection, and I know we did not have any other issues.

Q So looking at page six of the RCA, do you see a discussion under the heading "Operational Factors Potentially Impacting MHPS Blades", and then it has a subheading, "Low Pressure (LP) turbine Excessive Steam Flow - Running In The Avoidance Zone", right?

A Yes.

Q And these three paragraphs here are basically how you disposed of the issue of excessive steam flow, is that fair?

A It is.

Q Okay. And there is a reference here to the -- it says in the middle of that first paragraph: Based on hindsight, MHPS Engineering claimed at the time of the first failure (Period 1) Bartow Unit 4S exceeded the back-end loading limitation of 15,000 foot pounds per hour squared, is that the way to say it?

A The way I say it. There is actually a couple different ways, but pounds per hour per square foot.

Q Okay -- by many hours, and that the MHPS 40-inch L0 fleet average for back-end loading was closer to 12,000, whatever that is?

A Right.

Q Okay. And you don't disagree with those factual recitations about those numbers, either the L0 fleet average or the exceeding 15,000 foot pounds per hour squared?

A Yeah. What that represents is Mitsubishi's concern. So Mitsubishi's concern was that we were up in the 15,000 range with these blades, but the Mitsubishi fleet experience with 40-inch L0 blades was closer to 12,000 pounds per hour per foot squared. And that's what led Mitsubishi to conclude that, oh, it must be that back-end loading. So that's the concern that's stated.

I am not sure if I answered your question.

Q Well, do you disagree that you were operating above 15,000 foot pounds per hour squared in Period 1?

A I don't disagree with that calculation.

Q In fact, when you were at 450, you were more at, like, 17,000, right?

A I think that he is a good approximation, yes.

Q And you don't disagree that the -- you don't have any basis to disagree with the Mitsubishi fleet experience, right?

A That's correct.

Q Okay. So there is a statement in the middle of the next paragraph about how many hours in Period 1 you were in exceedance of the avoidance zone you talked about, right --

A Yes.

Q -- 2,466?

You agree with Mr. Pollock's testimony that for Period 1, you operated the turbine at, was it 2,972 or 73 hours above 420 megawatts?

A I do.

What's really important to understand about these hours and avoidance zone in Period 1 is they are back-calculated. This thing called the avoidance zone didn't exist until after the telemetry testing was done at the start of Period 3. And with the value gained from that telemetry testing, which then derived this avoidance zone, we said, well, why don't we look back at the other operating periods and see where are we operating in that avoidance zone during the other periods.

So it wasn't as if we were violating some kind of limit during Period 1. We back-calculated that we were in the avoidance zone for that many hours during Period 1.

Q Well, Mitsubishi never said that operating in the avoidance zone in Period 1 was a problem. They said operating above 420 in Period 1 was a problem, didn't they?

A No. See, again, technically, this is -- 420 is really a proxy for the 15,000 pounds per hour per foot squared, or maybe even 17,000 pounds per hour per foot squared, which is the calculated steam flow for the surface area on the L0 blade.

That was Mitsubishi's concern. It was not an operating limit. It was beyond their experience. It was an area of uncertainty and that they did not know about, and so they said that's what they believed. There was too much steam flow in the last stage.

Q Mitsubishi didn't say that you operated in the avoidance zone in Period 1, and that was the problem. That wasn't -- that was your -- that was a construct that you put on your evaluation in Period 1, right?

A I am sorry, could you --

Q Okay. Mitsubishi established the avoidance zone from, was it Period 3 forward?

A Correct.

Q Okay.

A They established the avoidance zone for Period 3 with the blade vibration monitoring system that was installed with those new blades in Period 3.

Q So the avoidance zone was established for a prospective purpose, right, by Mitsubishi?

A Correct.

Q Okay.

A It was -- well, let me make sure we understand.

So it was installed to make sure that we didn't have any more issues, so we created -- Mitsubishi did testing, and we were able to gather data that showed if you run in a combination of inlet pressures and exhaust pressures in certain areas, the blades vibrate too much, and so you need to avoid operating in those operating conditions.

And then we received guidance from Mitsubishi. They said, don't operate in those avoidance zones. If you have to ramp up or down through those zones of operation, don't spend time in those zones. Get right out of them. That was the guidance issued to make sure we didn't have an issue from Period 3 on. We still had issues even though we avoided the avoidance zone in Periods 3, 4 and 5.

Q Well, my question to you is that imposition of the avoidance zone was about going-forward operations, correct?

A Oh, yes.

Q Yes.

A But I think the avoidance zone and the steam flow can't be separated. The avoidance zone is related to the steam flow, this pounds per hour per foot squared, and that's what is being talked about here in the root cause.

Q By the same token, operating above 420 and steam flow can't be separated either, can they?

A They can be correlated. There are many different factors that determine what the generator can produce as opposed to the pressures and the flows and in the steam turbine. So there is a correlation there, no doubt, but you can't just use a megawatt output of the generator to talk about conditions in a steam turbine.

Q There is a high correlation between the amount of steam flow that gets you to 420 and above, right?

A There is. I think to try to really simplify, Mitsubishi is saying that the steam flow, the 420 and above would produce steam flow that would be beyond their operating experience in a zone that they were not certain of.

Q Okay. In the RCA, would it be fair to say that your analysis did not look at whether steam flows for the approximately 3,000 hours you operated the steam turbine above 420 megawatts caused material lasting damage to the non-blade portion of the steam turbine, did you?

A Are you looking at a specific part of the --

Q No. I am asking you if there is anything in your RCA where you studied the number of hours that you operated above 420 to determine whether it damaged the low pressure turbine.

MR. HERNANDEZ: Judge, I am going to object on vague because I am not sure I understand what the question is.

MR. REHWINKEL: Your Honor, I am trying to understand what the RCA did and didn't do. And my question is: Did the RCA study the amount of hours above 420 to determine whether that had impacted the low pressure turbine? That's my question.

A I think even better than just looking at hours -- and I don't know if that was a detail that the root cause team looked at or not. I suspect it was a detail that they looked at, but again, the root cause team had knowledge of -- in fact, firsthand knowledge for many of the team members of inspections that were done at every iteration at the end of Period 1, at the end of Period 2, at the end of Period 3, at the end of Period 4 and at the end of Period 5 to look at each stage of blades in the low pressure turbine; to look at each of the diaphragms in the low pressure turbine.

We had nondestructive examination conducted during those times to conclusively say that there was no damage in the low pressure turbine other than the snubbers and the shroud tips on the L0 blades.

Q Do you have a copy of Exhibit 105 in front of you? It's revised DEF response to OPC POD 31?

A I do not have 105.

Q It should be in that package there.

A I have 102, 103, 104, 115 and 116.

Q Oh, look to your left there, the red folders.

I am sorry.

A Oh, I am sorry. I covered it with my pictures. Okay, I have 105.

Q Now, would you agree with me that 105 is a response to an OPC POD No. 31?

A Yes.

Q Okay. And it's Bates numbered in the lower right-hand corner, so I am just going to refer to the last four numbers there.

Could I ask you to -- well, first of all, look at Bates 6868. And given your tenure at Progress, you are familiar with this kind of document, are you not?

A I am, yes.

Q Okay. This is what you do -- you meaning the executives and operational folks -- do to go to the Board to get approval to initiate a project?

A Well, it may or may not be the Board, but it is part of the project approval process. And based on the dollar value, the total project cost, there are different levels of approval.

Q I said board, I meant senior executive team --

A Yes.

Q -- is that right?

A Yes.

Q So we see here on 6868 all the executives,

like Jeff Lyash and Bill Johnson, et cetera, you see their names and initials for approval, right?

A Yes, I do.

Q Okay. And if we go to 68 -- this is called a business analysis package, right?

A Part of this is, yes.

Q Part of it, yes.

A Yes.

Q And the business analysis package says, here's what we need to do for the benefit of the company and its customers, and here's what it's going to do for them, and here's what it's going to cost to do it in very rough terms, is that fair?

A Yes, that's fair.

Q Okay. And the senior executives look at that information and they give you a thumbs up or a thumbs down, right?

A Yes.

Q Thumbs up is all these signatures and initials here, right?

A That's accurate.

Q Okay. So when we look on 6875, which is just a few pages in, we see that there was, I guess, an analysis done for business as usual, and that was basically the recommended case to build Bartow; is that

right? If you look on the prior page.

A So we are looking at 6875?

Q 74 and 75, I should say.

A Oh, 74 and 75. And so, yes, looking at the alternatives considered, I know -- I am familiar with these documents, and there were multiple alternatives considered.

Q Okay. And on 6875, in the, it looks like the second full paragraph starting with the secondary market; do you see that?

A Yes.

Q Okay. This is part of what was the chosen solution, is that right?

A Yes, it is.

Q Okay. Can you read that paragraph for me aloud?

A Sure.

A secondary market 400-megawatt steam turbine was found. The use of this turbine was investigated and proved to be a very good fit for the 4 CT and 4 HRSG combinations. In fact, it provided more operating flexibility (see operational analysis detail below). In addition, the uncertainty in project schedule and cost was reduced.

Q Okay. So this is -- this document is what the

senior executives would have reviewed to give the approvals that we see back on 6868?

A It's a piece of that document, yes.

Q Okay. All right. So there was an expectation that at the time this was approved by executives, that you were getting a steam turbine that was 400 megawatts in output, right?

A I would be very careful to characterize the actual capacity of any of the pieces of equipment based on this document. This is not a technical engineering document. It is a, like you said, a business analysis package. It gives the relative size of part of the equipment that's going to go into an approximate 1,200 megawatt 4-on-1 combined cycle.

Q Okay. Turn back to page 6911. This is page 3 of 27 of an IPP, which is integrated project plan.

A Yes, that's correct.

Q Okay. And we see over here -- in 2008, what would have been happening with the Bartow project where an IPP would be reviewed and approved?

A As far as what would be happening, could you give me more specific --

Q Well, you saw the BAP was approved in 2006, so that meant you could go ahead and execute on whatever contracts you had to do and spend the money, right?

A Right.

Q And that was kind of your authorization to conclude the contracting, I guess, for the Tenaska plant steam turbine?

A Yes.

Q Okay. So in 2008, if this IPP is dated -- these approvals look like on page 6907 they are in March of 2008. What's going on here?

A Well, I am paging back towards the beginning of the document. I am not familiar with -- and this is a long time ago before I was directly involved, of course.

Q Okay. 6861 -- 6881 is the beginning of that IPP and business analysis package, is that right?

A Yes. Could you -- I am sorry, could you state your question again?

Q So if we look on page 6885, we see -- I think they are looking for an additional $18 million of funding?

A On 6885?

Q Yes?

THE COURT: On the recommendation --

BY MR. REHWINKEL:

Q On the recommendation there.

A I see that, yes. I see it. So that is likely the purpose for this document --

Q Okay. We --

A -- you know, I don't know specifically, but what I do know is that the project was commissioned in June of '09, as we have previously discussed. It was well underway from a construction standpoint when this -- the date of this document. So it looks like they were looking for some additional funding.

Q Okay. And on 6911, which is where I wanted to ask you a question, we see Paul Crimi's name and his signature and a date, right?

A Yes.

Q Does that mean he was -- would have been involved in sort of the planning and implementation of the Bartow repowering project?

MR. HERNANDEZ: Objection, Your Honor. I think the witness is testifying he is not certain about this document altogether. He is not certain what's occurring here, and so there is a lack of a predicate for this question.

MR. REHWINKEL: My question is to ask him about Mr. Crimi, and I have a question later on that will tie this later on, Your Honor.

THE COURT: Again, I will overrule to the extent he can only answer what he knows. If he doesn't know, I think he is capable of saying that.

THE WITNESS: Well, so if you look at the signature blocks required here, it's -- this is a big decision for the company. It's a lot of money being talked about, a lot of funding, and there is a lot of executives listed here from multiple departments. It's not just the department involved with the construction. It's not just the department that would be involved with the operation of the unit.

Mr. Crimi, at the time, was an executive with a support services branch of the company, and so he was one of the required signatures of many executives. Since it was a large financial decision, there had to be buy-in from an alignment across the executive suite.

BY MR. REHWINKEL:

Q He was Executive Director of Power Generation Services, is what it appears to say here?

A Yes.

Q Okay. So based on your knowledge of the company at the time, would that have meant he would have had some operational responsibilities with respect to the steam turbine and the Bartow repowering?

A Actually, no, it would not have. He was -- as power generation services, that's technical expertise. It's engineering. It's not the operation of the unit. The operation would be some of the other signatures on this page.

Q Well, obviously, it wasn't commissioned at this time. I am talking about as far as implementing the project, when I said operational.

A Well, and again, as far as implementing the project, this looks like every executive in every department in the company was part of the decision to implement the project since it was such a big investment.

Q So in 2006, you executed a contract to buy the steam turbine from Mitsubishi, right?

A Subject to check, yeah. I don't remember if it was 2006.

Q But in 2006, Duke contracted with Mitsubishi, as your documentation says, to perform heat balances, correct?

A Yes.

Q And could you tell the judge what a heat balance is and what its intended output is?

A Sure. Any big new project like a new power plant, you have to try to -- well, the engineering analysis includes looking at many, many variables, in fact, a few dozen variables that can come into play to predict what the output of a unit will be.

There is different operating pieces of equipment that might be operating or not operating. There is different atmostpheric conditions. The temperature of the weather makes a difference. The temperature of the air makes a difference. The temperature of the cooling water makes a difference. The temperature of the cooling substance which might be hydrogen in the case of a generator. All these things are analyzed many different ways.

So, for example, on the Bartow combined cycle project, there were over 300 heat balance cases that were developed. And it seems excessive, there is over 300, but think about Bartow for a minute. It's a 4-on-1 combined cycle, so you might run a heat case that is with all four combustion turbines running and the steam turbine, so 4-on-1 operation, but without what are called duct burners running. And you might do that at 32 degrees. You might do it at 72 degrees. You might do it at 95 degrees ambient conditions.

And then each one of those ambient air conditions, you might do it at a different cooling water temperature, because all those variables make an impact on what the engineering prediction is going to be on the gross output of the power block.

So for Bartow, you would do it on 4-on-1, 3-on-1, 2-on-1, 1-on-1 configuration. You would do it with duct burners, without duct burners in service, which is a very significant part of the operation that I haven't talked about yet.

In the heat recovery steam generator, I mentioned how the exhaust steam -- or the exhaust gases, rather, from the combustion turbines, rather than go out in the atmosphere, which they would in simple cycle operation, they are captured and they heat water, but there is also capability built into these heat recovery steam generators that they are called duct burners. The natural gas-fired burners will light fire literally in the duct to put more heat in addition to the exhaust gases coming from the combustion turbine so that you can generate -- turn more water into steam. Generate more steam from the HRSGs. So whether duct burners are on or off is a very significant variable.

In addition, at the Bartow site, there is something called power augmentation in the combustion turbines. And this gets pretty technical, but you can actually extract part of the steam as it's going through the steam turbine before it reaches the condenser and then pipe it into the combustion turbines to augment the air and combustion gases that are turning the combustion turbines motor.

So you are putting some high pressure steam into the combustion turbines to make it generate more megawatts. You are stealing a little bit of steam from the steam turbine to do that, so whenever you use power augmentation in the combustion turbines, you turn on your duct burners to get more steam from the HRSGs to put back in the steam turbine.

THE COURT: Steam turbine, I got you.

THE WITNESS: So depending on what pieces of equipment are operating at Bartow, there is a great variation in how many megawatts the site is going to have as output. And so, like I said, over 300 different heat balance cases were generated as part of the project as engineering predictions on what the result would be.

BY MR. REHWINKEL:

Q So what is the primary output of a heat balance? Isn't there, like, a bottom line that comes out?

A There is a lot of output. I don't know that I can say there is a primary output.

Q Okay. Well, let's -- do you have a copy of Exhibit 108 in your red folder there?

A Yes, I have 108.
Q Now, this happens to be Mitsubishi's response to your RFP for the long-term solution, right, this document?
A Yes.
Q Okay. But if we -- if I could get you to turn, and I apologize I didn't Bates these, these Bates numbers at 2437, they are real tiny. If you go to 2435, you can see there is an electrical -- or there is a diagram, and then after that, I want to ask you something about the heat balances that are behind that.
MR. HERNANDEZ: So you want 437?
MR. REHWINKEL: Yeah, 437.
MR. BERNIER: It is small.
MR. REHWINKEL: Yeah.
BY MR. REHWINKEL:
Q Once you get into that area, you will see that there is an easier-to-read page 2 of 129, there is 100 --
A I think I am there.
Q You found it?
A Yeah.
Q Okay. And I apologize, I don't know why page 1 of 129 is not here. Our -- the document is Bates numbered consecutively, but I want to ask you if 2437 is

the output of the heat balances, one of the pages of the output of the heat balances that you just told the judge about?

A It is, and it's also on 2438, the columns follow down. There is so many variables involved.

Q Oh, yes.

A It's the same -- like, for instance, if you look across the top of 2437, this looks like it's Case 1 through Case 15 of the heat balance, and there is still more of Case 1 through Case 15 on 2438.

Q Well, go to 43, I think you will see at the bottom of that.

A And there is more on the page after that as well.

Q Yeah. Go to 2443?

A 2443.

Q Yeah. Is that where this -- these -- the cases are numbered across the top 1 through 15?

A Yes.

Q Okay. So these pages from 37 to 43, these are -- these all relate to the same --

A They do, yes.

Q -- long columns, right?

A Right.

Q Okay. And then we see on 44 there, there is a

whole new set of heat balances?

A Right, 16 through.

Q Okay. But let's go back to 37. And would it be fair to say that these are operating permutations, is that a fair way to say these are kind of postulated ways you could operate the unit, 1-on-1, 3-on-1, 2-on-1?

A I would say they are predictions --

Q Okay.

A -- based on varying different operating parameters.

Q Okay.

A And having different pieces of equipment in service or out of service.

Q Right, okay.

So when we look on -- in the bottom -- at the top a little bit, say, the top third of the page, we see on the left-hand side, run date, in the heading titles, right?

A Yes.

Q And if we follow that all the way across, it says 7 September, 2006?

A Yes, I see that.

Q Okay. So are these the ones that were done by Mitsubishi or by Bibb?

A I don't know, looking at them. I know -- let me look up at the title. These appear to be the ones done by Bibb.

Q Okay. Now, Bibb is an engineer, or an engineering firm that you hired to run heat balances in conjunction with Mitsubishi, so you knew what you were going to be getting out of this unit before you finalized the purchase, right?

A Well, Bibb was a little bit more than that. That's a piece of their scope. But Bibb was the engineer on the project, so we -- we, Progress Energy at the time, had a contract with a consortium that was Bibb and TIC constructors that together acted as the engineer procuring construct contractors for the entire project.

Both of them later merged and were bought by Kiewit. If you know what Kiewit is, Kiewit was in the business of doing EPC projects for companies.

So Bibb acted as the owner's engineer, but that's -- so what you just stated is a piece of the service they supplied.

Q Okay. But it is true that Bibb was your guy -- I don't know if it's a person or people -- that's your guy that represents you and makes sure that the heat balances are run correctly and that Mitsubishi agrees with the heat balances, is that fair?

A I -- it's -- part of it I know is fair. I don't about the Mitsubishi agrees piece. I don't know the ins and outs of how that's done in a large construction project.

Q Well -- okay.

So Mitsubishi -- didn't Bibb work with Mitsubishi to run these heat balances?

A I am sure there had to have been collaboration.

Q Okay. So let's look at -- above that run date, we see somewhere up in the mix, more than halfway up, it says STG output, do you see that?

A Yes, I do.

Q All right. And then in bold all the way across the page, we see variations of megawatt outputs under these heat balances, right?

A Correct.

Q All right. So these are -- it's bolded. This is a primary result that you are looking for out of the heat balances. It tells you what the bottom line is you are going to get out of this, you expect to get out of this unit under these predictions or permutations, right?

A It is one of many things that we are getting out of this, yes.

Q But like you told the executives when you said

400, that's kind of the bottom line when you get a steam turbine, is what are you going to be able to generate in terms of electricity to serve customers, right?

A Could you ask that again, I am sorry?

Q Yeah. When you are buying a steam turbine, the bottom line is what kind of megawatts can you get out of it, right?

A That's one of the -- well, the efficiency is one the Keys. In fact, I would say efficiency is even more key in a big project like this, because ultimately the long-term cost to the customer comes down to how efficient are you converting fuel energy into a product.

Q Right. So would you agree with me that heat balances were run and certain cases were selected and used for the contract that you determined -- that you executed with Mitsubishi?

A Yes.

Q There were two heat balances that were part of the contract guarantee that Mitsubishi said they were warranting the unit to put out?

A That's correct. I have seen other documents where two of these heat balance cases were chosen and were included in the contract language relative to liquidated damages.

Q Okay. And one of the outputs -- one of the

heat balances was 389, and that was a certain configuration, correct?

A I believe that's correct, yes.

Q And the other was 420, right?

A That's correct.

Now, a really important point here, you are picking one. Let's look again at how many pages of data is in each one of these heat cases. It's multiple pages, right? I won't count them, but at least five or six pages.

One of these -- for example, one of these variables is power factor. And I can't read it, I am having a hard time reading it. I wish I could point to the row. If I could get a magnifying glass, I could read it to you. But I have read through these before. I have looked at all 300 plus of these P cases.

The power factor assumptions are really key, because when you think about a generator, an electrical generator, the power factor of the electrical system has great bearing on what the generator is able to do.

So in each of these cases, there is an assumed value-of-power factor. And so for the assumed value-of-power factor in case number 48, which you are referencing, which ended up 420 megawatts of the steam turbine, it was at a power factor of .949. We don't run at a power factor of .949. We run at a power factor close to one, which we call unity.

And this might be a good time, Mr. Bernier has a drawing, I could explain power factor, and I think this is quite important.

MR. HERNANDEZ: May I approach?

THE COURT: Yes.

THE WITNESS: And again, this is just an example of --

MS. BROWNLESS: Mr. Swartz, I am sorry, when you hold the paper up, I can't see.

THE WITNESS: I am sorry, I will stand up.

MS. BROWNLESS: Thank you.

THE WITNESS: There is so many variables, as you see in all these pages, that go along with these heat balance cases. All of them have an impact on the capacity of what the unit is going to run. So I am picking one that's called power factor because I think it's pretty important.

Power factor is a measure of the efficiency of how load current -- we produce load current from our generator, megavolt-amperes, all right. How efficiently can we make that -- I am not there yet. This is a donkey pulling on a barge. I will get there in a second. A efficiently we convert that load current into voltage, into real power, rather, is really important to us. It's really important to all of our customers. We want to do that as efficiently as we can.

So we have -- there is a measurement called power factor that measures that efficiency. We want to be as close to one as you possibly can be. A 1.0 power factor means you are being as efficient as you can converting load current into real work.

In the real world, there are loads. There is motors; motors at FIPUG; motors at PCS Phosphate that are creating a drag on the system. They are creating the system to do extra work.

But also in the real world, we have equipment that -- and that makes the power factor drop less than one -- to go down into maybe -- when I say less than one, I am talking decimal places. It might go down to .9 or to .95. But we have things on our electrical system that keep it up close to one called capacitor banks that are in service all the time, because we want to make that conversion as efficient as possible for the benefit of our customers.

So to make it real simple, power factor is just like in this picture. A power factor of one, for this horse to pull this barge through the canal as efficiently as possible, the horse would have to walk on water, right, and be directly in front of the barge. If you are directly in front of the barge pulling it, the horse is going to have to do less work and it won't heat up as much to pull the barge.

The greater the angle becomes this direction, more of the work of the horse is pulling this way and less of it is pulling straight down the barge. And so the greater this angle is, as the horse is pulling the barge down the canal, the more overheated the horse might come because it's harder. It's harder work. The power factor is lower in that case.

So the generator is -- the analogy is to the electrical generator. The generators are rated by power factor as part of the rating, and there is curves -- and there is curves in a lot of this information that we saw that you can see based on power factor how much a generator is capable of putting out.

And these heat balances, the power factor was assumed to be various numbers; ..9 was used in many of the examples of heat cases; .949 was used in the one you are referring to. Our system runs between .97 and .995 all the time. Our generator at Bartow can do more than 420 megawatts because it's closer to walking straight ahead of the barge. The 420 is at a power factor .949, which is not where we run.

So the 420 megawatts doesn't apply to the steam turbine. It's part of the generator, and our generator is capable of doing more than that because our power factor runs closer to unity.

I hope it made sense. It's an odd -- it's a difficult-to-understand electrical concept.

BY MR. REHWINKEL:

Q So none of the P balances that are shown in this exhibit, we call it 108, showed a expected output above 420, maybe 420.2, but nothing up to 421 or above, right?

A I didn't see -- they don't, but I also didn't see any power factors above .949.

Q Okay. You would agree that the contract contained expected megawatt output of 420 megawatts, correct?

A At an assumed set of conditions, including power factor, that is correct.

Q So at the time you talked to senior executives and contracted with Mitsubishi, both Mitsubishi and Duke

expected the steam turbine to put out 420 megawatts at normal operations, right?

A The expectation would be that the predicted heat case would be achieved.

So, again, let's be really clear. What Mitsubishi and the project team used, they used heat case number 48, which used a power factor of .949. It predicted a megawatt output of 420. They used that as the minimum thing that Mitsubishi had to achieve in order to get full payment on the project. Anything below 420, there would have been liquidated damages that Mitsubishi had to pay to Progress Energy.

So the 420 was actually a contractual minimum that had to be achieved. And again, it was at a lower power factor than we actually run at. So everybody would have known that the steam turbine generator can produce more than 420 megawatts.

Q Do you have Exhibit 116 with you still?

A Let me get organized here.

Q I would ask you to turn to page 21 when you get there.

A I do have 116. Page 21?

Q Yes, sir.

A All right, I am there.

Q Now, this is a Mitsubishi document. And do

you disagree that the Bartow steam turbine was designed to operate at 420 megawatts, as the OEM says?

A I agree that there is a case with certain variables, and you can see there is pages of variables that go in. And if the variables are at those particular numbers, then 420 is the predicted output. And that was used as a contractual minimum that Mitsubishi had to achieve.

Q Well, in the second bullet, it says a heat balance diagram providing max operation, parenthesis, 420 megawatt, thermal conditions was provided as part of the thermal kit. Do you disagree with that?

A That's what it says. And my interpretation of that is the maximum the generator can put out at those conditions at a power factor of .949 is 420 megawatts.

Q Okay. And then the next bullet there was -- it says: During the performance test in 2009, using the 420-megawatt thermal conditions, the unit was able to reach approximately 402 megawatts; is that right?

A That's correct.

Q And the performance test here was when you were installing the unit. Sometime before you commissioned it, you did a test to see whether it met the contractual terms as far as that guarantee, right?

A That's correct.

Q And is this factual?

A Yes.

Q All right. So let's go to Exhibit 109, which is the contract. And I want to go to actually attachment Appendix A.

A Appendix A?

Q Yes, sir. It starts at Bates 12419.?

MS. BROWNLESS: Excuse me, Charles. Just so I understand, this is the page that says Contract No. 270810, Amendment 005?

MR. REHWINKEL: Yes.

MR. BERNIER: Mr. Swartz, I think it's after the first divider sheet.

THE WITNESS: I found it. I am sorry. I just found it.

BY MR. REHWINKEL:

Q All right. So you agree with me, this is part of the contract for the steam turbine, right?

A I do.

Q Okay. And if I get you to go to Bates 12437. This is 3.3 Basis for Guaranteed Performance, as a header, when you get there.

A Okay, I am there.

Q Okay. Is this how the electrical output of the turbine was calculated? Is this the formula?

A It is.

Q Okay. And if we go over to 12439, just for the -- to follow up on your testimony about the power factor. We see those -- this is what you were talking about -- power factor is .9 and .949?

A It is. On that -- the table in 4.2, you can see those in the third row down in each column.

Q Okay. And they also have condenser back pressure assumptions that correlate to those outputs, is that right?

A Yes.

Q So -- and we see that -- is it true that the Case 28 was a 4-x-1 configuration, and Case 48 was a 3-x-1 configuration?

A Case 28, to my memory, was a 4-x-1 without duct burners. And Case 48, to my memory, was a 3-on-1 with full duct burning.

Q Okay. Does this document here, or the heat balances, or any other documentation that you can point to demonstrate that Mitsubishi or Bibb told you that you could get more than 420 megawatts of output from the steam turbine?

A Well, I believe you can look at some of this documentation and reach that conclusion, yes.

Q Because of the power factor?

A Yes.

Q Okay. But did anybody tell you that it would be perfectly normal to operate the unit above 420 megawatts per -- as much as you wanted?

A That's not a typical conversation. So the Bartow combined cycle, just like any other project, you talk about what the capacity is you are going to get out of the site. And in this case, I think some of the documents referred to a number maybe 1,278 or 1,279 megawatts, something like that. But there are many, many variables that come into play as far as the output of your machine. In the wintertime, when it's colder, when the cooling water temperature is lower, we can run with better condenser vacuums much more efficient.

So to give you an example, our Duke Energy Florida fleet, in the summertime we can produce about 10,000 megawatts of power. In the wintertime, we can produce about 11,000 megawatts of power. And the difference is the colder weather, the colder cooling water that helps the machines be more efficient in the wintertime.

So you have to make sure you are understanding. Every time you are talking about a rating of a piece of equipment, you have to understand all the other conditions that are part of that predicted rating. And it would be a really bad thing to say you have to adhere to this one case out of more than 300 and never exceed that because you would be leaving potential capacity on the table that could be used for the benefit of our customer.

So let's expand Bartow, the Bartow is a steam turbine. You know, Bartow is a 1270-megawatt site. The steam turbine is, you know, 400, 450 megawatts, somewhere in that range. But it's different in the summer than it is in the winter.

But if we were to apply, say, summer ratings, and then in the wintertime, when we need 11,000 megawatts to serve our customers, we would have to buy expensive fuel, or we would have to put on less efficient generating units to great expense for our customers.

So you have to understand all the variables associated with a rating. Our job as operators is to make sure we stay within the operating parameters that are given by our equipment manufacturers and get the most out of our machines that we can without exceeding those parameters. And that's what every operator does. That's what every utility should be doing, and that's certainly what we did with Bartow.

And there is one more thing I would like to say. So to answer your question directly, if you go to page 12596 in this same document. It's way back there. It looks like this.

MS. BROWNLESS: What's the number again, sir?

THE WITNESS: In the lower right-hand corner, it's 012596.

So, Your Honor, are you there?

THE COURT: I am there.

THE WITNESS: This is the capability curve of the generator for this project. And this is the page that shows that you can get more than 420 megawatts if the power factor is greater than .9.

And I know this is hard to read, but this line right here going up at a positive angle is a .9 power factor line. And you can see it intersects the generator capability curve. If you come down, you see that's right at 420 megawatts.

We run closer to unity, closer to one. And if you go all the way across, that's almost 470 megawatts. And if you look up at the very top of this piece of paper, you can see there is a rating up at the very top. It says 468000 kVA, that's kilovolt-amperes. That's the reactive power that this generator is capable of putting out. Power factor is the kilowatts divided by the kilovolt-amperes.

So you can see the kilowatts is only 420.2 -- 421.2. It's 421,200 kilowatts. So it's 421.2 megawatts. But with a power factor closer to one, you can get closer to 468 megawatts out of this steam turbine. That's what that information is telling you. So in the same document, they are saying you can get greater than 420 megawatts.

BY MR. REHWINKEL:

Q So 468, is that approximately the rating of the generator?

A Correct.

Q Okay. So --

A The -- well, kVA, to be more precise. And it depends on the power factor, and whether or not you can get that much megawatts, the real power out.

Q So is it Duke's position that as long as you stay within the IP, HP and condenser limits, that if you could get to 468 on a regular basis, that you would be -- it would be perfectly okay to operate -- have operated that unit in 2001 -- Period 1? I am sorry.

A Right. You have to look at other parameters as well. Again, it's hazardous to look at just any one parameter, but this gives you an idea of what the capability of the generator is.

So we have a piece of equipment attached to the steam turbine that's capable at the power factors we run of doing in excess of 460 megawatts. So as long as we can stay within the operating parameters of the steam turbine, and those are pressures and temperatures, why don't we try to get as much output from the generator as we can.

Q Do you have Mr. Pollock's exhibit RAP-5 with you?

A I do. Okay, I am there.

Q You got that, okay.

And this is a document you prepared at our request, the Public Counsel's request, right?

A Yes.

Q Okay. So there is no question about the validity of this data, and accuracy of it, right?

A I will say I know that there is -- this is -- it uses averaging. And it depends on how often you sample a data point, and that can cause discrepancies in the data. It's a good representation, I will say that.

Q Okay. And this document here is what Mr. David referred to in his opening. It has the operating hours above 420 as distributed on this chart, is that

right --

A Yes, it does.

Q -- with that approximation caveat?

A It does.

Q So I just wanted to ask you about this, because as you were talking about being able to increase the output based on certain efficiencies, including ambient temperature, weather, right? And what I mean now, I am talking about the air temperature and the water temperature, right?

A Sure.

Q Let's look at period of 2010. Would you agree with me that -- and would you also agree with me that the months of June through September are your hottest months?

A I would.

Q Okay. And we look at here, we see a fairly large distribution of the operating time above 420 in the hottest months, right?

A Yes.

Q Okay. So it wouldn't necessarily be a reasonable conclusion to suggest that you operated this high above 420 -- or this much above 420 because the weather was colder, right?

A Well, you have to understand what else is going on at the plant at the time. So our ability to pump that cold or warmer water through the system is really important. You are not going to get the efficiency unless you are able to pump it.

And what I know is when we first commissioned this plant, and during the first several months of operation -- and I don't know how long it went into 2010, but we had some great difficulty with what's called the circulating water system, which circulates the cooling water through the equipment, including the condenser underneath the steam turbine.

My conclusion from this data would be that once we straightened that out and were able to fully pump water through the condenser, we started really taking advantage of what we could from an installed equipment standpoint. Also understanding that in any new operation, there is a period of learning for the operating staff as well. But I know we had these equipment issues with the circulating water system for the first several months of operation.

Q But in 2010, there is not -- in fact, it looks like you have more hours above 420 --

A I think --

Q -- in the hot months than in the cooler months, right?

A Right, because I think in the cooler months, we were still having trouble with the circulating water system. I don't know that, but --

Q Okay. And before 2012, you did not do an engineering analysis that showed that it was possible to operate the unit above 420, did you?

A Well, I think we had all kinds of information that showed that it was possible to operate above 420. In fact, if we could, let's refer back to the contract for a minute.

I will have to find the exact page, but again, the 420 megawatts that you keep referencing was a contractual minimum that Mitsubishi had to meet in order to get full payment on the project. So just that fact alone tells everybody that above 420 is okay. 420 is the minimum that had to be achieved. And that's in this contract. I will just have to -- if you give me a moment, I will find the page.

Okay, so if you turn in the -- let me see what the exhibit number is. It's the contract. It's the very large document, Exhibit No. 109. And if you turn to the Bates numbers 012434 in the bottom right hand. Well, it's even better if you page to 12432, which is two pages before that, 12432.

And you can see in paragraph 3.2.1 that the

420.07 is a liquidated damage performance guarantee, which means that's the minimum that the project had to achieve in order to get full payment on the project.

Q But it says in 3.2.12: MPS Net Steam turbine Maximum Electrical Output 420.07, right?

A Yes, that's referring, in my opinion, to that generator capability curve that I just showed you. It's at a lower power factor than we operate. So again, you have to make sure any time you talk about a rating, you have to make sure you understand all the variables that go into that rating. In this assistance, it used a power factor that we can far out achieve.

Q Okay. So in 2012, after you had the first discovery of blade damage, isn't it true that you went to Mitsubishi and asked them for their help in telling you how you could operate above 420?

A I would phrase it a little differently than that.

So we opened up the steam turbine for a routine inspection in the spring of 2012. We found five of the mid-span snubbers that had damage. We were concerned with that. So we consulted with Mitsubishi. They recommended we don't continue running with those snubbers broken. That could lead to blade failure, which would be catastrophic, as I have described earlier.

At that time, Mitsubishi, as we've seen and you pointed out, they were concerned we were running higher than their fleet experience from a pounds per hour per square foot standpoint in the last stage blade, so they gave us, for the first time, a lower operating limit.

And in this case, if we could turn to my -- to JS-2 in the root cause, I can show you what the operating limit is. It's page 5 of 18, Table A in JS-2, or JS-1.

Are you there, Your Honor?

THE COURT: I am just about there. Yeah, I am there now.

THE WITNESS: Okay. So in that table, you can see it has columns for each of the five periods. And the one, two, three, four, the fifth row down says MHPS IP exhaust pressure operating limits.

So it's at the start of Period 2, because of that damage we found, following Mitsubishi's recommendation, we replaced all of the blades on just one end of the machine because all five snubbers were damaged on the same end of the machine, I believe on the turbine end. It says in this chart. I am not looking at it.

And if you look at the picture over here, you can see that the machine has two ends. The generator is coupled to the right-hand side, and the HP IP turbine is coupled to the left-hand side. So on the turbine end of the machine, we replaced all 64 L0 blades.

Before we started operating again in April of 2012, Mitsubishi, in order to make sure that we didn't exceed their operating experience with 40-inch L0 blades, they put this 118-pound limit on the intermediate pressure turbine exhaust. And in this case, that served as a proxy.

Why that intermediate pressure exhaust rather than the low pressure turbine inlet. There was no pressure instrument on the low pressure inlet, but there was one on the intermediate pressure exhaust, so that was used as a proxy.

And if I could stand up just a minute just to make sure everyone understands. Mitsubishi was concerned, as I described, with the steam flow, but there was no pressure instrument on the pressure going into the low pressure turbine, but there was one coming out of the intermediate pressure. So there is just a slight amount of pressure drop across this pipe.

So we used this pressure as a proxy for the low pressure turbine inlet. It was more conservative than what had been in the past, so the combination --

And I am sorry, but I forgot what your question was, but, yeah, we put a more conservative operating limit in place based on pressure, which is consistent with operating parameters that we followed from the start of Period 1 throughout each of the periods.

BY MR. REHWINKEL:

Q So I asked you if, after the failure, you went to Mitsubishi and asked for them to help you --

A Right.

Q -- increase the output in the unit.

A So it's just not so simple as that. It's a very collaborative back-and-forth process, but because we then had to -- we followed this lower, more conservative guidance on the IP exhaust pressure, we were not satisfied that we were getting as much out of the equipment as we could, so that's when we did ask Mitsubishi.

So we don't want to have this limit. We weren't supposed to have this limit. We want to get as much out of the generator as we can. Is there something that can be done?

They studied it and came back with us -- to us and said, yes, we can redesign the L0 blades and put a different design of blade in both L0 rows, and you will be able to achieve, we estimate, 450 megawatts.

Q Well, are you familiar with the quote that they gave you for an engineering study for additional optimization and reliability for $232,025?

A Could I see that?

Q Yeah. It's on -- it's in Exhibit 102 at Bates 145. It's the late filed exhibit for 145.

A I have 102. Could you say the Bates number again, please?

Q Yeah. It's kind of two-thirds of the way or more back, it's at 145, and it's a real tiny print up in the upper right above the slide.

A I am almost there. Okay, I see that.

Q Do you know what this was for?

A I don't recall what this was for.

Q Okay. If you roll back a few pages to 135.

A Okay, I am there.

Q And this is a part of, I guess, a slide presentation at a joint meeting between Mitsubishi and Duke?

A I am looking back at the beginning to see if I can get an idea.

Q On 122, it talks about August 21st, 2012, discussion.

A Okay. It does appear to be a meeting where we discussed the turbine.

Q Okay. Just back on 135, a discussion -- further discussion to support their own investigation and possible means of increasing unit output.

And then it looks like they have a response. It says: We will continue technical support for you. As of now, it is difficult for us to propose a concrete method to increase the unit output. An engineering study is suggested.

And so my question is, is that what 145 is, is them saying here's what it will cost you for us to do an engineering study?

A It does appear to be that, yes.

Q Okay. And did you engage them to do that study?

A I don't recall if we engaged them to do this study, or if that was included in the ultimate -- we did contract with them to supply new blades that could -- that were theoretically going to be able to raise the output to about 450 megawatts.

Q Okay. So that would have been the most likely

output product of this study if you did, in fact, say, yes, go ahead and do that?

A That -- I would say that would be a likely output, yes.

Q Okay. Now, did that study say that Mitsubishi agreed that you could run the unit above 420 without different blades?

A Well, I am not familiar with the study, but -- so if I could have a few minutes to read it, but I think it's really important to remember that at this point in time, Mitsubishi thought that the root cause was too much steam flow in the low pressure turbine, and that they -- there was a way to get from steam flow and correlate it, as you have already said, to megawatts.

So that's been disproven in later cases, later periods of time. So I am not sure what your question is.

THE COURT: I am going to jump in while we are on a pause here.

One thing we didn't have in our order of procedure was a lunch break. I am just wondering what the will of the, you know, the room is as far as taking a break and how long you think we need.

MR. BREW: Yes, I think we should have one.

MS. BROWNLESS: Yes.

THE COURT: We agree on that. How long? Should we try to get back inside of an hour, or is it going to take an hour?

MR. REHWINKEL: I think an hour is reasonable.

THE COURT: Okay. We will -- we'll say, then, we will reconvene at 120:20, and if everybody, by some miracle, is back sooner, we will start sooner.

MR. REHWINKEL: Okay. Sounds good.

THE COURT: We will stand in recess then.

(Lunch recess.)

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 18th day of February, 2020.

____
DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #GG015952
EXPIRES JULY 27, 2020

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

RE IN: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR,

Petitioner,

vs. CASE NO. 19-6022

**,

Respondent.
_______________________________/

VOLUME 1

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PROCEEDINGS: Administrative Hearing

BEFORE: Honorable Lawrence P. Stevenson

DATE: February 4, 2020

TIME: Commenced: 8:55 A.M.

LOCATION: Division of Administrative Hearings
1230 Apalachee Parkway
The DeSoto Building,
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter and
Notary Public in and for the
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INDEX TO WITNESSES

INDEX TO EXHIBITS

NO.	DESCRIPTION	IDENTIFIED	ADMITTED
114	Revised Comprehensive Exhibit List	11	11
115	RCA draft	35	
116	3/18/2015 40-inch blade telemetry	35	

*Huh-uh is a negative response
*Uh-huh is a positive response

P R O C E E D I N G S

THE COURT: We will go ahead and call the hearing to order.

We are here today in the case styled In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor. It's DOAH case number 19-6022. It's a Public Service Commission case.

My name is Lawrence Stevenson. I am the Administrative Law Judge assigned to hear the case. And I guess at the outset, we should get appearances entered. I am just going to go in the order that's in our little -- we've got a little cheat sheet here for how we are going to handle this proceeding.

Representing Duke Energy.

MR. BERNIER: Good morning, Judge Stevenson, Matt Bernier on behalf of Duke Energy.

MR. HERNANDEZ: Good morning, Your Honor. Daniel Hernandez with Shutts & Bowen on behalf of Duke Energy.

MR. BERNIER: And, Judge, I would also enter an appearance for Dianne Triplett, who will be here shortly.

THE COURT: Okay. I have got her, so that's

good.

MR. HERNANDEZ: And, Your Honor, seated with us is Mr. Jeff Swartz. He's a representative of the company, and also will be testifying as a witness.

MR. SWARTZ: Good morning, Your Honor.

THE COURT: A face with all the testimony I have read. That's good.

And Office of Public Counsel.

MR. REHWINKEL: Good morning, Your Honor, Charles Rehwinkel with the Office of Public Counsel.

MR. DAVID: And Thomas A. "Tad" David with the Office of Public Counsel.

MR. BREW: I am not with the Office of Public Counsel.

THE COURT: Okay. Very good.

MR. REHWINKEL: And, Your Honor, I would like to enter an appearance for J.R. Kelly, the Public Counsel, he's here with us.

THE COURT: Okay. I have got Mr. Kelly checked off as well.

And for -- I still don't have the acronym down. Is it FIPUG?

MR. MOYLE: FIPUG, it's Florida Industrial

Power Users Group.

THE COURT: I am more comfortable saying that.

MR. MOYLE: Right, and that's fine. Judge Peterson, we recently had a case and he called us Florida Industrial, and so we will answer to anything, Your Honor.

THE COURT: That's good. With me, I think power users, whatever.

MR. MOYLE: So I'm Jon Moyle with the Moyle Law Firm representing the industrial users, and Karen Putnal of our firm is also here, I would like to enter an appearance for her as well.

THE COURT: Okay. Very good.

And PCS Phosphate.

MR. BREW: Yes, Your Honor. For White Springs Agricultural Chemicals, PCS Phosphate, I am James Brew from Stone Mattheis Xenopoulos & Brew.

THE COURT: Very good.

And last but not least, the Public Service Commission.

MS. BROWNLESS: Good morning, Your Honor. My name is Suzanne Brownless, appearing on behalf of the Florida Public Service Commission staff. Also appearing is Bianca Lherisson. And we would like to enter a notice of appearance for Keith Hetrick,

our General Counsel.
THE COURT: Okay. Very good.
And our next order of business I guess is to close the hearing. I have to rely on counsel to be my police in this respect. I am assuming that, as of now, everyone is in the room belongs in the room, is that correct?
MR. BERNIER: I believe that's correct, and I have asked the counsel for the other representatives to let me know if somebody enters and they are a member of their party so we don't have to disrupt anything.
THE COURT: Okay. That's fine.
MR. BERNIER: But if somebody does that we don't know, we will let you know.
THE COURT: That's fine. I guess I will give you a high sign if I see someone.
Mr. Rehwinkel.
MR. REHWINKEL: Your Honor, I don't know if our microphones are working. The light is not coming on.
THE COURT: Gee. That's not in my bailiwick. I mean, I can hear you fine.
MR. REHWINKEL: Okay.
THE COURT: We are not -- I just don't know if

the court reporter can.
COURT REPORTER: I'll let you know.
THE COURT: Okay. The first break, I will go talk to somebody about it and see what we can do.
MR. DAVID: The switch was off.
THE COURT: Oh, is that it?
MR. DAVID: Yeah.
THE COURT: There is a little green light that comes on.
MR. REHWINKEL: Thank you.
THE COURT: Okay. Well, we've got exhibits. Did we want to get the exhibits up here at this time?
MS. BROWNLESS: Yes, Your Honor.
As you know, we've already stipulated to exhibits on the comprehensive exhibit list, Exhibit Nos. 1, 68 through 76, 80 through 82 and 100, and those have been previously provided to the Court and the parties.
We have other exhibits on the comprehensive exhibit list that have been marked for identification, and I believe the parties also think that there is no need to authenticate those documents. Do I have that correct?
MR. HERNANDEZ: That is correct, Your Honor.

MS. BROWNLESS: Okay. And so what we would like to do at this time is hand out a revised comprehensive exhibit list.
THE COURT: Okay.
MS. BROWNLESS: And at this time, we would like that marked as Exhibit No. 114 and ask that it be admitted into evidence.
THE COURT: Hearing no objections, we will mark the exhibit -- the revised comprehensive exhibit list as staff -- Commission staff Exhibit 114, and show it admitted.
(Whereupon, Exhibit No. 114 was marked for identification and received into evidence.)
MS. BROWNLESS: Thank you, Your Honor.
THE COURT: And I think that takes care of all of our business up to the opening statements.
I went through my usual list of questions that I ask at the beginning of a hearing, and I know this is not a conventional hearing. The only one that I sort of want an answer to, I think I know the answer to this, but I want it on the record is who has the burden, and what is the burden in this proceeding? I sort of assume it's probably Duke Energy and it's probably by a preponderance, but --
MR. BERNIER: Yes, sir.

THE COURT: -- do we have sort of agreement on that?
MR. BERNIER: Yes, sir, we agree with both of those.
MR. REHWINKEL: Yes, sir.
THE COURT: Okay. That takes care of any concerns that I had.
And at this time, I guess we can move on to opening statements. And was there agreement as to who goes first? I am assuming it would be Duke.
MR. BERNIER: I think so. So I will go ahead.
Thank you. Good morning, again, Judge Stevenson. Matt Bernier for Duke Energy.
The issues presented to you today can be boiled down to one overarching question, and is that did Duke Energy prudently operate the Bartow steam turbine? Now, the Public Service Commission's prudent standard asks did DEF act as a reasonable utility manager would given the information it knew or reasonably should have known at the time it acted?
And this is not a hindsight review, because with the benefit of hindsight, most reasonable people can identify something that they would do differently.

In this case, the preponderance of the evidence shows that DEF acted prudently at all times given the information DEF knew or should have known, because DEF, at all times, operated the machine in compliance with the manufacturer's guidelines, which is the standard industry practice.

Now, Duke Energy purchased the Bartow combined cycle steam turbine from Mitsubishi Power Systems. The steam turbine was designed for use by a third party, but that project never came to fruition, and the steam turbine was never delivered to the third party.

Prior to the purchase, Mitsubishi was responsible for ensuring the turbine was compatible and acceptable for the use at Bartow. They were also responsible for providing Duke Energy with the operating parameters for the unit. DEF was responsible for operating the unit within those parameters, which it did.

Notwithstanding DEF's compliance with the operating guidelines, during a planned outage in the spring of 2012, after approximately three years of operation, damage was discovered on the last stage of blades in the low-pressure turbine. The

last stage blades are also referred to as the L0 blades. You will hear both, and we have an actual representation of the blade over there on the side of the courtroom for you so you can see it.

THE COURT: Oh, okay. I walked right by it.

MR. BERNIER: So that's what we will be talking about today.

We also have a diagram that staff has provided of the operation and the actual steam turbine with CTs and everything that Mr. Swartz and maybe Mr. Polich will be referring to.

Now, DEF discovered the damage during an inspection as part of an unrelated outage and consulted with Mitsubishi, which recommended replacing the L0 blades on the turbine end of the steam turbine prior to restarting operations. The damaged blades were replaced and the operating parameters were also adjusted by Mitsubishi, resulting in the establishment for the first time of a new exhaust pressure limit on the intermediate pressure portion of the turbine.

Now, during of this second period of operation -- and you are going to hear us referring to different periods of operation, and those periods are shown on Mr. Swartz's Exhibit JS-2,

it's No. 80 on the comprehensive exhibit list, and it's Duke Energy's root cause analysis. That breaks it down into the various periods you are going to hear us discuss throughout this hearing.

During the second period of operation, DEF complied with the modified operating parameters, but DEF wanted to return to the output from the machine that it was previously able to provide when operated to its original higher specifications. To be clear, beneficially extracting as much energy from the steam being produced by the combustion turbines benefits Duke Energy's customers.

Therefore, during Period 2, DEF contracted for new heavy-duty blades that would allow the machine to produce additional megawatts. When the unit was removed from service to install these new upgraded blades, damage was discovered on the Period 2 blades. So at the outset of Period 3, Mitsubishi installed temporary blade vibration monitoring to allow for telemetry testing to better understand what was happening with the blades.

As a result of that testing, for the first time, Mitsubishi created an avoidance zone, which is a combination of steam pressure and condenser pressures that should be avoided or minimized

during stable operations, and that was communicated to Duke Energy around four months into Period 3.

Again, notwithstanding DEF's compliance with these new operating parameters, including avoiding operation in the newly-established avoidance zone, the new upgraded blades again suffered damage. For the first time, however, the damaged areas shifted from the mid-span snubbers, which I believe is right in the middle of the blade, and shifted out to what's called the Z-locks, which are at the end of the blade. And this led DEF to the conclusion that the modifications simply shifted rather than corrected the blade issues.

This Period 3 experience led to further blade modifications and reduced operating parameters in addition to the avoidance zone for the Period 4 operations.

Once again, although DEF complied with the reduction and operating pressures, knowing that those modifications to the operating specifications would result in reduced output for its customers, the Period 4 blades were also found to have damage after approximately five months of operation.

At this point, DEF determined the best course of action was to go back to the first iteration of blades, which, coupled with further reduction in steam pressure, was thought to provide the best chance of event-free operation while Duke Energy and Mitsubishi could more fully understand the cause of the damage. However, DEF's operators detected an indication of blade damage in these Period 5 blades after only approximately 1,500 hours of operation.

Again, the blades were damaged even though the unit was operated pursuant to the most conservative guidelines provided to date. Therefore, DEF determined the prudent intermediate path forward was to replace the last-stage blades altogether with pressure plates. These plates allow steam to pass through the turbine but do not rotate and, therefore, do not contribute to generating power resulting in a reduction in potential generating capacity. However, the pressure plates did allow for event-free operation for the benefit of Duke Energy's customers.

It's also important to remember that DEF was able to discover each instant of blade damage -- instance, excuse me -- before catastrophic failure could occur.

As this course of events was playing out, and

in addition to cooperating with Mitsubishi on their various root cause analyses, which I think you will hear about today, DEF was engaged in performing a root cause analysis analyzing the information gleaned from each of the different incidents.

DEF's root cause analysis specifically considered six potential failure causes, three operational causes and three design causes.

Ultimately, DEF determined that none of the reviewed causes in isolation or in combination could explain the various blade episodes. Thus, DEF was left with one conclusion: The blades' lack of adequate design margin did not allow the blades to operate without incident at even the reduced operating pressures recommended by the equipment manufacturer.

Said differently, under normal operating conditions within Mitsubishi's operating guidelines, the blades were not designed to handle the pressures found within the low pressure turbine. DEF had no way of knowing this information. It prudently relied on Mitsubishi and operated the machine according to their instructions, as it would any other machine across its fleet.

Now, Public Counsel's witness, Mr. Polich, based on his review of documents, has determined that the cause of the failures is very simple. He believes that DEF ran the steam turbine too hard in the first period of operation. More specifically, Mr. Polich concluded that the operation of the steam turbine in a manner that produced over 420 megawatts caused the blade damage, and had the unit not been operated in this manner, the original blades would still be in the machine and operating today.

This conclusion is contradicted by the later episodes that occurred without reaching the operation levels Mr. Polich asserts caused the damage.

During his deposition, Mr. Polich candidly agreed that DEF operated the unit prudently in each period other than the first.

Of course, if DEF operated -- prudently operated the blades in those latter periods, as Mr. Polich agrees, and the blades still suffered damage, there must be a cause, and that cause is the lack of adequate design margin as DEF has concluded.

Now, not only does the later operating

experience and blade damage at lower operating pressures show that the original blade damage was not caused by operating in excess of 420 megawatts, Mr. Polich also admitted that he does not and cannot know at what point during Period 1 the original blades failed.

Because he cannot know when the original blades were damaged, it follows that he does not know how the steam turbine was being operated at the time the damage occurred, or whether the damage occurred when the unit was being operated above or below 420 megawatts of output.

Now, obviously this begs the question, how can he be so certain that it was simply operation above 420 megawatts that caused this damage?

Now, this is important, because under Mr. Polich's definition, operating below 420 megawatts was prudent. And if the damage occurred during prudent operation, the damage is certainly not DEF's fault.

And Mr. Swartz will testify that the Bartow plant was operated pursuant to industry standards and in line with the best interest of customers. The goal of plant operators is to maximize the output of generating units. This allows the

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utilities to avoid building additional generation or operating less cost-effective units to meet demand and, therefore, it saves customers money. Moreover, his testimony demonstrates that the steam turbine was at all times operated by the guidelines provided by Mitsubishi.

In short, DEF operated the steam turbine prudently from commissioning up until the February 2017 outage, and prudently installed pressure plates in place of the malfunctioning blades while a long-term solution could be devised, tested and implemented. Therefore, DEF should be permitted to recover its prudently incurred costs.

And I apologize for taking so long, that's more than I have ever said. Thank you.

THE COURT: I guess Office of Public Counsel goes next.

MR. DAVID: Yes, sir. Good morning, Judge Stevenson.

My name is Tad David with the Office of Public Counsel, and we represent the customers of Duke Energy Florida. We are here to establish facts, facts that we contend showed Duke Energy made foreseeable errors in the operation of its Bartow plant, errors that cost money, money that Duke

Energy now wants its customers to pay.

As you will see from the evidence, the sequence that links the customers to these errors is tenuous, but the link between Duke Energy's imprudent decisions and these errors is direct and proximate. Further, we will show that Duke initially concluded that the damage was caused by its operation of the plant.

As an investor-owned utility in Florida, Duke has a duty to make prudent and reasonable decisions in operating its generation facilities, and regarding any items that add cost for customers.

In this case, Duke had the resources and information that should have informed them of the proper operation of the Bartow plant. They knew or should have known that the way the Bartow plant was being operated was beyond the prudent operation of that plant. Through the exercise of due diligence and prudence, Duke should have understood that the output was entirely too good to be true. Their imprudent operation directly damaged this plant and cost money.

In this case, we are asking that the fuel clause recovery requested by Duke be reduced by an amount equal to the additional fuel cost caused by

Duke's imprudent operation of the plant, additional costs they are now trying to recover from customers. These costs should not be paid by Duke's customers.

No documentation exists that showed shows the manufacturer ever indicated that the steam turbine could generally be operated to produce an output above 420 megawatts during the initial period. The steam turbine was not designed to operate above 420 megawatts for any extended period of time. And the contract with Mitsubishi, who was manufacturer of the steam turbine, did not contemplate it operating above 420 megawatts of output.

For the period of July 2009 through February 2012, Duke operated the steam turbine above 420 megawatts for a total of 2,972 hours, including 2.4 hours above 450 megawatts, 1,555 hours above 440 megawatts and 2,302 hours above 430 megawatts.

As Mr. Bernier mentioned, in March of 2012, upon a routine inspection of the low pressure section of the steam turbine, Duke discovered that parts of the turbine were damaged. Since that time, for the past eight years, Duke has been trying to fix this steam turbine.

The evidence will show that the problems, and more importantly the costs at issue in this case cascade from Duke's operation of the Bartow plant in that initial period of operation from 2009 to 2012. This was Duke's fault.

The first evidence that Duke requested Mitsubishi consent to run the plant above 420 megawatts was in July of 2012, after the damage had been discovered in the first period.

The reply to this request was basically, hold on, you know, let's be careful. After the damage was discovered in March of 2012, the steam turbine never again consistently achieved 420 megawatts, except during very limited periods in a testing environment.

Later in 2012, Mitsubishi indicated that they could do an analysis of the circumstances that might allow the plant to produce -- to consistently produce 420 megawatts, but this analysis would cost $232,000 just to perform the analysis. There is no evidence that Duke commissioned Mitsubishi to perform this analysis.

In March 2018, Duke completed a root cause analysis of the problems experienced with the steam turbine at the Bartow plant. This root cause analysis was originally initiated to establish the cause of the damage discovered in -- during the first period beginning, you know, in March of 2012.

Drafts of this root cause analysis indicate that Duke engineers initially acknowledged that Duke contributed to the damage by introducing excessive steam pressure into the low pressure section of the steam turbine.

Over time, Duke's root cause analysis drafters softened the role that the excessive steam pressure played in the damage and focused instead on the blade design issues that followed the initial damage and failures.

We do not know the reason behind all the subsequent edits or revisions, however, you know, presumably not because the admitted information strengthens the argument that it was not -- the problems were not Duke's fault.

The evidence will show that no similar Mitsubishi steam turbines with the same blades has had blade damage or failures like that experienced at the Bartow plant.

Through Mr. Swartz's direct and rebuttal testimony, Duke will try to invert the cause and effect in this case. They will point to situations

after they damaged the turbines to support the idea that similar but not identical situations did not damage the turbine during the initial period.

The evidence they will try to use, in fact, shows that Duke decided it was easier to ask for forgiveness than permission to increase the output from the steam turbine and that Duke imprudently operated the turbine in such a fashion that it was damaged, potentially irreparably damaged.

This case, as you have already heard, revolves around some technical subjects. We will discuss succinctly as possible how this particular type of power plant works; how the operation of the plant affects the components of the plant; and how the operation and the resulting breakdowns have increased the cost of operating the plant.

Lastly, we will explain why it is appropriate for only prudently and necessarily incurred fuel expenses to be recovered from ratepayers in the fuel clause.

We cannot forget, Duke bears the burden of proof in this case to establish its entitlement to the recovery of replacement power costs as prudently and necessarily incurred. We are certainly not here to suggest that Duke Energy or

any of its employees are bad. The bottom line is that someone at Duke made errors, foreseeable errors that cost money, money that Duke Energy now wants its customer to pay.

We believe that you will see that Duke, not its customers, should be the one that bear these additional avoidable costs.

Thank you.

THE COURT: Thank you, Mr. David.

Next will be Mr. Moyle.

MR. MOYLE: Thank you, Your Honor.

Again, Jon Moyle for the Florida Industrial Power Users Group.

Your Honor, my client is comprised of a number of entities that use a lot of power 24/7, and the cost of power is important to them. A lot of them compete in markets not only in the United States, but internationally. I characterize them as folks in the pulp and paper business, the phosphate business, the chemical business, metal recycling. There is a wide variety of folks. I just wanted to share that with you to give you a little sense of why I am here and who I represent.

I think that, as noted, the burden of proof, obviously, is very important. I don't think there

is a disagreement that Duke bears that burden. And they have a tough burden to overcome. As you heard, I don't think it's really in dispute that Duke operated this plant initially when they got it out of a warehouse in Japan.

They brought it over, it sat in a warehouse for, I think, a number of years in Japan. And when they brought it here, they ran it beyond its 420-megawatt capabilities. And I don't think you will hear disputes about that, that in terms its operation, it was beyond that.

So with that fact going in, I think they have a tough hill to climb to show, well, notwithstanding that, we still should recover the monies in dispute.

And I think it's also helpful for -- to put in context the monies in dispute here. These issues, as you know, are a couple of issues that in the fuel docket. And the fuel docket is an annual docket that the PSC opens. All of us are in it and participate in it.

And in the fuel docket, of which these two issues have been spun off for your consideration, Duke -- the Commission has already ordered that Duke recover, its a big number, 1.3 billion approximately -- for the record, 1,303,329,632 -- and that's in an order from the PSC. So what we are arguing about today is give or take approximately one percent of monies that have already been ordered to be recovered by the Commission.

And in terms of thinking about how to make the opening point with you, you are going to hear a lot of technical information today. But I think it's important to note that, you know, the ratepayers, I would draw an analogy of the ratepayers maybe to a homeowner who is going to get a new home built. And the homeowner contracts with knowledgeable people, an architect and a general contractor to build a home. And if a construction defect occurs, the homeowner is inclined to say, that's on you all, because I don't have expertise in this. I relied on you. And I think that ratepayers are in a similar position.

It's a regulatory compact. These are monopolies, but the ratepayers surely don't have the expertise in these areas. And what you have here is you have Duke kind of pointing the finger at Mitsubishi and saying, well, we think it's a design defect. And why do they say that? I mean,

largely because largely because they can't identify the problem that occurred.

And Mitsubishi is saying, no, we think you overran the plant at the beginning, that you put too much steam through it, and you all caused the problem.

So there is a lot of uncertainty there. These are complicated machines. Overrunning it at the beginning, does that have a downstream effect that these turbine kept breaking?

What we do know is that the turbines continued to break and not be operational. And the result was is that they had to go out and get extra power, and that's what we are arguing about today.

But I think it's important that the customers, you know, not bear this risk. I don't think Duke can make -- prove the burden. And I am going to spend a little time asking about, well, how is it between Mitsubishi and Duke? I mean, shouldn't you all figure out who is responsible for this?

And I think you will hear a little bit from Duke's witness about, well, we really couldn't get them to assume risk because it's too great of a risk for going out and buying power and -- you know, but respectfully, we don't think that risk

should fall on the ratepayers, particularly in this case, because we don't believe Duke can carry their burden of proof.

So thank you for the opportunity to share those thoughts with you.

THE COURT: All right. And PCS.

MR. BREW: Thank you, Judge Stevenson.

PCS Phosphate operates their phosphate mining operating in Hamilton County. It is by far one of the largest electric loads on the Duke Energy system, and so affordable power is crucial to their operations and fees, quote. That's why we are here.

You will find that everyone at these tables will agree that in its roughly 11-year history, the Bartow plant hasn't run as expected, that there are a series of events all involving the last level of blades, the L0 blades and the failures, and you will get a real education on that.

What we also agree on is that the manufacturer of the steam turbine, Mitsubishi, has no prior experience anywhere in the world with what has happened at Bartow; that Duke has no prior experience operating a combined cycle facility in the configuration of this plant.

And it's important to remember that when the steam turbine is running, it always runs at 3,600 RPM when it's connected to the grid. And so you are going to hear a lot about the five initial period that were studied in the root cause analysis. I just want to focus on the last one, which occurred in February 2017, where a fragment of one of the blades flew off at 3,600 RPM, which means that it was carrying a velocity roughly comparable to a speeding bullet through the turbine until it hit something and caused some damage.

And that's what we are talking about in terms of replacement fuel is the downtime while they initially decided how to repair from that damage, where the decision was to take all the blades out, all the zero level blades out and put in the pressure plate that Mr. Bernier talked about, which downgraded the unit, so it was -- it lost about 10 percent of its production capacity that consumers have had to deal with for almost three years now.

It's been our concern on rebuilding the record that we still don't know if the plant is fixed. We still don't know if the real root cause has been addressed; that Duke and Mitsubishi worked together when they finally decided to focus on vibration levels to do some actual telemetry testing for vibration, and they are now insisting that their vibration monitoring be part of the new fix.

So to our mind, Duke hasn't really established that it has still figured out how to repair the plant, but clearly the burden lies with them.

Thank you.

THE COURT: And the Commission.

MS. BROWNLESS: We will waive opening statements. Thank you.

THE COURT: I don't know whether you are here as a referee or what. Thank you.

MR. REHWINKEL: Your Honor --

THE COURT: Yes, sir.

MR. REHWINKEL: -- if I could interject. I have a housekeeping matter.

We have a copy of the documents we were required to bring today. Would you like me to give you those now?

THE COURT: Sure. That would be fine.

MR. REHWINKEL: Okay. And I also wanted to mention that we've identified exhibits. There are two additional exhibits that we have distributed to all the parties that I would just ask at this

time -- oftentimes at the Commission, when we have cross-examination exhibits, we don't normally pre-identify them, but I have done that.

One of them is an exhibit that is excerpts from what would be Exhibits 102 and 103, and I have talked to counsel for the company about that. Everyone has it in the red folders that we've distributed, and I would just ask if I could get agreement that that would be admitted into the record under the same conditions that the other documents have and given a number?

MR. BERNIER: Which one was the excerpts from 102 and 103? Of this?

MR. REHWINKEL: It's in the first one. It's got the tabs on it.

THE COURT: So you are saying, Mr. Rehwinkel, you want these sort of pulled out and identified as a separate exhibit?

MR. REHWINKEL: Yes, Your Honor. They don't have a number at this time, but assuming that we have no objection to it, I think it would be given No. 115.

THE COURT: 115.

MR. REHWINKEL: It would be called draft -- RCA draft exhibit. And then there is one other one

which would be 116, and it would be March 18, 2015, 40-inch blade telemetry. And that's the other envelope that says telemetry on it.

MR. BERNIER: So we have no objection to this being marked at this time. Based on the questions that are being asked, there may be objections at that point. I don't know yet, so I will withhold right to object at that time.

THE COURT: Okay. We will just identify them.

MR. BERNIER: Identify them for discussion.

THE COURT: Identify as 115 and 116.

(Whereupon, Exhibit Nos. 115 & 116 were marked for identification.)

MR. REHWINKEL: That way we won't have to do that then. I will give you your set.

MS. BROWNLESS: Excuse me, Charles, I just want to make sure I am doing this correctly. This RCA draft exhibit is 115?

MR. REHWINKEL: Yes.

MS. BROWNLESS: And what is 116?

MR. REHWINKEL: It's in the other pouch, and it's the last one. It's the last document. No, it's a skinny one.

MR. BERNIER: I have another question. Is there a copy for the witness when they are up

there?

MR. REHWINKEL: I don't have one.

MS. BROWNLESS: What does it say on the outside, Charles?

MR. HERNANDEZ: It does not have an exhibit number on the top right-hand, so it's blank.

MS. BROWNLESS: I'm sorry.

MR. REHWINKEL: It has a cover on it.

MR. HERNANDEZ: That's it.

MS. BROWNLESS: Okay.

MR. REHWINKEL: Yeah.

MS. BROWNLESS: Thank you for being patient.

MR. REHWINKEL: I apologize for going off the schedule there, but I thought it would be better if we just got this taken care of.

THE COURT: That's fine. That's perfectly okay.

MR. REHWINKEL: Okay.

THE COURT: If there is no other preliminaries, I guess we are ready for Mr. Swartz.

MR. BERNIER: Thank you. Duke Energy calls Mr. Jeff Swartz.

THE COURT: Mr. Swartz. You have already offered testimony, but I will swear you in.

Raise your right hand.

Whereupon,

JEFF SWARTZ

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

THE WITNESS: I do.

THE COURT: Have a seat.

EXAMINATION

BY MR. BERNIER:

Q Mr. Swartz, could you please provide your name and job title for the record, please?

A Jeff Swartz. I am the Vice-President of Generation for Duke Energy Florida.

Q Thank you.

And on or about March 1st, 2019, did you cause to be filed direct testimony in the 2019 fuel docket before the Florida Public Service Commission?

A Yes, I did.

Q And do you have a copy of that testimony with you today?

A I do.

Q If I were to ask you the same questions here today, would your answers be the same?

A Yes.

MR. BERNIER: Judge, at this time, we would

ask that Mr. Swartz's prefiled direct testimony, dated March 1, 2019, be entered into the record as though read.

THE COURT: Hearing no objections, we will show that done.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20190001-EI

MARCH 1, 2019

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

A. I am employed by Duke Energy Florida ("DEF" or the "Company") as Vice President – Generation.

Q. What are your responsibilities in that position?

A. As Vice President of DEF's Generation organization, my responsibilities include overall leadership and strategic direction of DEF's power generation fleet. My major duties and responsibilities include strategic and tactical planning to operate and maintain DEF's non-nuclear generation fleet; generation fleet project and additions recommendations; major maintenance programs; outage and project management; retirement of generation facilities; asset allocation; workforce planning and staffing; organizational alignment and design; continuous business improvements; retention and inclusion; succession planning; and oversight of hundreds of employees and hundreds of millions of dollars in assets and capital and operating budgets.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the United States Naval Academy in 1985. I have 17 years of power plant and production experience in various managerial and executive positions within Duke Energy managing Fossil Steam Operations, Combustion Turbine Operations and Nuclear Plant Operations. While at Duke Energy I have managed new unit projects from construction to operation, and I have extensive contract negotiation and management experience. My prior experience also includes nuclear engineering and operations experience in the United States Navy and project management, engineering, supervisory and management experience with a pulp, paper and chemical manufacturing company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with information related to the Bartow Steam Turbine (ST) forced outage that occurred from February 9, 2017 through April 8, 2017, including background information on the event that led to the outage, an explanation of DEF's responsive actions, a presentation of DEF's root cause analysis and findings, and an explanation of DEF's reasonable and prudent restoration actions.

Q. Please provide a summary of your testimony.

A. On February 9, 2017, the Bartow steam turbine was removed from service due to an indication of a sodium leak into the steam water cycle. During this shutdown, DEF discovered a failed LP turbine rupture disk. The disk had been breached by a foreign object that caused a hole in the rupture diaphragm. DEF performed an inspection of the Bartow Steam Turbine ("ST") and discovered damage to the ST's L-0 blades (and determined part of an L-0 blade ruptured the LP turbine rupture disk), resulting in a forced outage to the ST that lasted until April 8, 2017 (while the ST was off-line, the Bartow combustion turbines ("CTs") remained available to run in simple cycle mode). DEF performed a Root Cause Analysis ("RCA") that determined the failure of the Bartow ST's L-0 Blades was caused by events beyond DEF's control, and DEF could not have reasonably prevented the failure from occurring. The results of DEF's RCA were discussed in more detail in my March 1, 2018 testimony filed in Docket No. 20180001-EI, which I adopt and incorporate as if fully set forth herein. DEF's actions prior to and in the wake of the blade failure were reasonable and prudent.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the DEF RCA Report, attached as Exhibit No. __ (JS-1) to my March 1, 2018 testimony filed in Docket No. 20180001-EI.

Q: Is the RCA considered confidential by the Company?

A: Yes. Portions of the RCA's findings are considered proprietary and confidential by the blades' manufacturer. In order to protect the OEM's rights, this information has been treated by the Company as proprietary confidential business information and has not been made publicly available. As part of the stipulation reached on Issue 1B in Docket No. 20180001-EI, DEF committed to work with the OEM to revise the confidentiality request; DEF intends to fully comply with that stipulation.

Q. Please summarize the events leading up to the 2017 Bartow event.

A. Bartow is a 4x1 Combined Cycle ("CC") Station with a ST manufactured by Mitsubishi Hitachi Power Systems ("MHPS"). The ST was purchased from a company that intended to use it for a 3x1 CC with a gross output of 420MW. The ST was never delivered to that third party but instead remained with MHPS in a warehouse in Japan until DEF purchased the unit in 2006.

Before the ST was purchased, DEF contracted with MHPS to evaluate the ST design conditions and to update heat balances for a 4x1 CC configuration. CC units blend steam from the CTs as they start-up and/or shut-down with steam to the ST. These blending events result in brief periods of higher steam temperatures and flows into the condenser below the ST L-0 blades, a common occurrence for CC units.

Since commissioning of the Bartow ST in 2009, there have been five (5) events involving L-0 blade failures and/or replacements. The latest blade failure occurred when a "loss of mass" event resulted in a blade fragment traveling through the Low-Pressure Turbine rupture disk diaphragm.

Q. What actions did DEF take in response to the February 2017 failure?

A. The Company took three primary actions in the wake of the event: a root cause team was established to investigate the incident and prepare a root cause analysis; a restoration team was formed to bring the unit back on-line; and a team was formed to evaluate a long-term solution for Bartow.

Q. Please describe the process DEF followed to ascertain the root cause of the event.

A. DEF created a RCA Team consisting of internal experts to investigate and determine the root cause of the event. The RCA Team consisted of seven individuals with expertise in engineering, operations and process, and human performance.

Following industry standard procedures, the RCA Team employed specific tools used to determine potential root cause(s) including: interviews, event and causal factor review ("E&CF"), flawed barrier analysis, change analysis, component analysis, visual inspections of the equipment, photographs taken following the event, engineering calculations and measurements, and detailed review of outage reports and maintenance logs.

DEF's findings are fully set forth in the RCA identified as Exhibit No. __(JS-1) to my March 1, 2018 testimony in docket No. 20180001-EI and as summarized in my testimony of that date. To avoid unnecessary repetition, those findings will not be rehashed here.

Q. What restoration process did DEF follow to bring tl service?

A. It's important to recall that the four Bartow CTs were able to continue operation in simple cycle mode (i.e., without operation of the ST) notwithstanding the blade failure. DEF worked with the OEM to identify and implement an interim solution that would allow the ST to resume operation, ultimately resulting in the installation of a pressure

plate in place of the L-0 blades on March 22, 2017. The plate allows the ST to operate increasing the energy output of Bartow above what was possible in simple cycle mode. As mentioned above, the ST returned to service on April 8, 2017.

Q. Could DEF have reasonably prevented the event and the ensuing outage at Bartow?

A. No, the outage was caused by circumstances beyond DEF's reasonable control, as demonstrated by the RCA. DEF was not at fault.

Q. Did DEF act reasonably and prudently to restore Bartow to service in a timely fashion?

A. Yes, DEF took reasonable and prudent steps to develop a restoration team and guiding processes to restore the Bartow ST to service. The restoration team followed those processes and the unit was successfully brought back on line in a timely manner.

Q. Did DEF's agreement with the OEM include a provision obligating for the OEM to contribute funds towards replacement power costs in the event of an outage caused by the OEM's product?

A. No; to the contrary, the agreement specifically disclaimed any liability for consequential damages.

Q. In your experience, do DEF's agreements with OEMs usually include a similar disclaimer of liability?

A. Yes. In my experience OEMs are not willing to accept the risk of agreeing to pay consequential damages (such as replacement power costs) given the uncertain and potentially open-ended liability. To my knowledge, this is the case throughout the industry.

Q. Have you or anyone under your supervision engaged in negotiations with a vendor that was willing to accept consequential damages as part of a component part purchase order?

A. No, in DEF's experience, vendors do not offer to accept consequential damages as part of the terms and conditions of their agreements. Further, when DEF has indicated that such a provision would be a required part of the agreement, vendors have indicated they would withdraw rather than agree to those terms. DEF simply has not found such a provision to be commercially available.

Q. Does that conclude your testimony?

A. Yes.

BY MR. BERNIER:

Q Mr. Swartz, have you prepared a summary of your direct testimony?

A I have.

Q And could you provide that, please?

A Certainly.

Good morning, Judge Stevenson. Again, my name is Jeff Swartz. I am the Vice-President of Generation for Duke Energy Florida. I will say DEF in the future. That meanings I have overall responsibility for DEF's generation fleet.

My direct testimony provides background regarding the issues that have arisen over the past few years with the Bartow combined cycle plant steam turbine, an explanation of DEF's response to those issues, including a summary of DEF's actions to restore the unit to service as quickly as possible. And finally a presentation of DEF's root cause analysis.

In short, after analyzing data from each of the blade failures that I will discuss in a moment, DEF determined that the only causal factor that explains each failure, and accounts for the different conditions attended to each failure, is that the blades lack sufficient design margin to effectively operate in the Bartow steam turbine.

Bartow steam turbine was manufactured by Mitsubishi Hitachi Power Systems. The combined cycle was placed into service in the year 2009.

And briefly some background. A combined cycle power plant uses both gas and steam turbines together to produce electricity. Combustion of natural gas in the gas turbine turns a generator producing electricity, and the waste heat from the gas turbine is routed to a heat recovery steam generator, or HRSG, producing steam routed to a nearby steam turbine which generates extra power. It is coupled to a generator.

Combined cycle plants can be set up in multiple configurations and provide for great operational flexibility. The Bartow combined cycle is called a 4-on-1 plant, meaning there are four natural gas fired combustion turbines, four heat recovery steam generators which provide steam to the one steam turbine. It can operate in a 1-on-1 configuration, a 2-on-1, a 3-on-1, a 4-on-1; or, when necessary, the gas turbines can operate in what we call simple cycle mode to generate electricity when the steam turbine is off-line.

The steam turbine itself is made up of a high pressure/intermediate pressure section which is a combined section, and a low pressure section as well. Each has a series of blades that, as the steam passes

through the blades in the turbine sections, it spins the blades which, in turn, spin the rotor. The rotor is connected to a generator, and the generator is what produces electricity.

At issue in this proceeding is the low pressure section, specifically the last stage of blades in the low pressure section. They are called the L0 blades. The low pressure turbine at Bartow is a dual-flow unit, meaning the steam is admitted in the middle of the turbine and then flows axially in opposite directions through rows of blade. So thus, there are two rows of L0 blades, one at each end of the machine.

And if I could, Your Honor, I think it if I could stand up at this point --

THE COURT: Sure.

THE WITNESS: -- and use some of these exhibits over here, it might be helpful. I think I am going to move of this out of the way so everybody can see.

First, this is a overall plant. This is the combined cycle plant. This is the gas turbine right here. The gas turbine can run on its own. Gas is admitted in the middle. The combustion process of gas and air, compressed air spins a rotor, spins blades, spins a rotor, turns this generator producing electricity.

In simple cycle mode, the exhaust gases from that combustion just flow up this stack to the atmosphere. The beauty of combined cycle operation is that we can take that energy that's in that heat and swing a damper and make the gases flow this way instead.

All this represents what's called the heat recovery steam generator. It's a boiler. There is water in tubes that heat, and these exhaust gases heat the water in the tubes, and then the water is turned into steam. That steam then is then reused in the turbine generator unit. It's admitted into the high pressure turbine, and then actually sent back to the heat recovery steam generator, reheated to get more energy into the steam. If you raise the temperature of the steam, it raises the energy level. It's then readmitted to the intermediate pressure turbine. But this is really one shaft with blades connected to it.

And then the exhaust from this intermediate pressure turbine goes to the low pressure turbine, and some steam from the heat recovery steam generator comes into the low pressure turbine into the middle, flows in both directions, and then is

exhausted into a condenser.

This, again, is rotating the shaft. This is one common shaft that's bolted together here and bolted together here, and then the generator produces electricity.

And like I said, at issue in this proceeding is the last stage of blades in this low pressure turbine. So it would be right here and right here, the longest stage of blades. The blades get successively longer as the steam flows through the machine because the steam is losing energy as it travels through the machine. It's transferring energy to the blades making them rotate. The blades have to be bigger and longer in order for the lower energy steam to have any effect. So the longest blades are the L0 blades.

This is an actual L0 blade from the Bartow combined cycle low pressure turbine. There is -- you can see it's curved. This is the blade itself. It's very heavy. It's about 60 pounds. A big piece of metal.

The issue that we've had is that the mid-span, there is something called snubbers. And at the tip, there is something called Z-locks or a shroud. These blades aren't connected to one another

during -- when the turbine is stationary. When the turbine starts spinning, and someone already said, it spins at great speed, 3600 revolutions per minute, so 60 cycles per second.

Think about that. It's spinning that rapidly, and this is just one of 64 blades on the low pressure turbine. So it's quite a large diameter machine at this stage of the turbine.

These blades, you wouldn't be able to see it, but they untwist a little bit, just a tiny bit, and it makes these mid-span snubbers and these Z-lock tips come together, which strengthens the whole machine.

You get a segment in the middle of the blade and a segment at the tip of the blade that helps strengthen the entire machine. If not for that, these blades would vibrate more and potentially crack from high cycle fatigue, and that would be very disastrous and catastrophic if a piece of the blade were to come loose.

What we've had happen four different times was a piece of either the snubber or a piece of this Z-lock tip, or pieces have come off, come apart. So when we talk about blade damage, it was limited to the Z-lock tips or the snubbers.

And I wanted to make that clear, because through proactive action, we were able to find that damage before the blade itself was damaged, which could have been much more catastrophic.

Thank you for allowing me to show that.

So since being placed into service, the steam turbine has experienced five separate L0 blade incidents. Importantly, each instance was discovered either, as I said, by proactive inspection or by installed monitoring equipment, and DEF was able to take appropriate action prior to any catastrophic damage to the turbine itself.

As we discuss the incidents and throughout these proceedings, you will hear reference to different periods of operation. Period 1 is the time from when the units were first commissioned in year 2009 until discovery of the first blade issue. Period 2 began when the damaged blades were replaced and the unit returned to service, and so on.

Each period was accompanied by blade modifications, with one notable exception I will discuss momentarily, as well as modified operating parameters provided by Mitsubishi.

Steam turbines are operated within the

guidelines provided by the manufacturer. Those guidelines are based on the manufacturer's calculations of permissible steam flows, pressures and temperatures. With one exception in Period 3, when new hardened blades were installed, each operating parameter modification lowered permissible pressures which resulted in a corresponding reduction in electrical output from the generator.

Notwithstanding DEF's adherence to these operating instructions, each period concluded with discovery of blade damage. Of particular importance to DEF's root cause analysis was the experience of Period 5. The lessons learned from that period have significant importance because the blades used during that time were of the same design as the original iteration, and L0 blade damage was discovered despite the unit being operated well below the originally provided operating parameters.

Therefore, DEF's operation of the unit was not the cause of the iterative blade damage. As mentioned earlier, after analyzing the available data from each of the operational periods, and taking note of the fact that blade damage continued

to be discovered even after the operating pressures were curtailed, DEF determined that the ultimate causation had to be the blades' lack of sufficient design margin.

With the discovery of the blade damage at the end of Period 5, DEF determined that the most prudent means of returning the steam turbine to service while a long-term solution to the blade issues could be determined, designed and implemented was to replace the last stage blades with what are called pressure plates, as Mr. Bernier said.

It's important to remember that while the unit was off-line and the pressure plates were being installed, the four combustion turbines continued to operate in simple cycle mode and provide service to our customers.

For reference, a pressure plate is just what it sounds like, it's a non-rotating plate, as Mr. Bernier mentioned. Instead of a blade reducing the pressure and the energy of the steam before it goes into the condenser, there is holes drilled in the pressure plate which reduce the pressure so that the steam then doesn't damage the condenser. So it takes that work out of the steam without the

benefit of making extra productive work, a product.

So the pressure plate does not use the steam passing through it to produce electricity and, therefore, there is a decrease in efficiency because the unit is not getting all the available energy of the steam passing through it.

However, the pressure plate allowed for the unit to return to service quickly and to operate event-free for the past two-and-a-half years.

Because DEF did not and could not know that the blades in question did not have the necessary design margin, and because DEF at all times operated the unit within the OEM's operating parameters, DEF's actions leading up to and in response to the February 2017 outage were prudent, and DEF should be permitted recovery of its prudently incurred replacement power costs.

I look forward to answering your questions. Thank you.

MR. BERNIER: Thank you, Judge. We will tender Mr. Swartz for cross-examination.

THE COURT: Is there an agreement as to order of cross? Public Counsel is first?

MR. REHWINKEL: Yes.

EXAMINATION

BY MR. REHWINKEL:

Q Good morning, Mr. Swartz.

A Good morning.

Q Can you tell me your full name, please?

A Jeffery Raymond Swartz.

Q Okay. And you are the Duke witness alone, who alone is here to provide whatever evidence you feel is most relevant to meet your burden to demonstrate that Duke acted prudently in operating the Bartow steam turbine; is that right?

A Yes, sir.

Q Would you also agree with me that JS-2 is the principal piece of evidence that Duke submits as your explanation of the cause of the failure of the various sets of blades at the unit?

A Yes.

Q And just for the record, JS-2 was the same as JS-1, it just has a different level of confidentiality, right?

A Correct.

Q The RCA -- can you agree with me that if I ask you about an RCA, it means a root cause analysis?

A Yes, that's correct.

Q Okay. And this RCA is the sum of the evidence that you contend proves that Duke acted prudently at all

times; is that right?

A Yes.

Q And, Mr. Swartz, isn't it also true that sometime after March of 2012, Duke began, at least informally, the process of determining a root cause of the problems that you identified after the March 2012 discovery of the blade damage?

A Yes, that's correct.

Q And am I correct in assuming that a root cause analysis is important to any utility as a way of understanding their operations for and understanding and apply lessons learned and improving processes for safety and efficiency purposes?

A Yes. Absolutely.

Q And that RCA process is part of the Duke culture?

A It is.

Q Would you agree with me, to be effective, the RCA process must be objective and honest and designed and executed to get to the truth, even if it's not a flattering view of how the company conducted operations?

A Yes.

Q Would you also agree with me that a true RCA should not be an advocacy document, that it --

A Could you ask that again, please?

Q Would you agree with me that a true RCA should not be an advocacy document that is biased in its scope or analysis?

A Correct. It should dig into the issues and understand the lessons learned so we can improve. That's the purpose.

Q Okay. The RCA should also not be designed to reach predetermined or confirmatory conclusions, should it?

A Correct.

Q Would you agree with me that the final RCA document that was ultimately prepared was at least in part done so with an eye toward making Duke's case to the Florida Public Service Commission that you believed you were not imprudent in the actions related to the blade failures and the need to buy replacement power?

MR. HERNANDEZ: Objection, compound.

THE WITNESS: The root cause --

THE COURT: Hang on.

THE WITNESS: Sorry.

THE COURT: Yeah, could you break it down? It was two questions there.

MR. REHWINKEL: Okay.

BY MR. REHWINKEL:

Q Would you agree that the RCA was produced, at

least in part, with an eye toward making your case to the Public Service Commission?

A I would not think about it that way. The root cause was truly to dig into what happened, what can we learn from that? How are we going to improve?

There are many -- not many, but there are times when we have root causes, or any causal analysis when there is a likelihood that there might be legal proceedings attached to it, and so we will make sure that we follow certain guidelines from an attorney-client privilege standpoint, which we did in this one because we thought that there could be, but it wasn't what you are suggesting. It was truly to get at the issues and learn.

Q Okay. So is it also true that the RCA is your final product of an inte -- well, let me ask you this: When I ask you about an RCA -- if I ask you about the RCA, or the Duke RCA, can you agree with me that we are talking about JS-2?

A Yes.

Q Okay. So is it true that the RCA is your final product of an iterative and continuous root cause analysis process that dates back to 2012?

A Yes, that's correct.

Q And can we also agree that if I ask you about

the September 22nd, 2017, Mitsubishi RCA, that I will specifically refer to that as Mitsubishi's RCA; you understand that?

A I understand.

Q Okay. And when I ask you -- or when I say Duke, can you agree with me that even though Duke's merger with Progress Energy occurred in July of 2012, that any relevant actions or inactions that transpired, or should have done so, under the control of Progress Energy Florida's management are the same as if those things happened or didn't under Duke's management control?

MR. HERNANDEZ: Objection, Judge, calls for a legal conclusion.

THE COURT: I will overrule. I mean, if you know.

THE WITNESS: Could you ask that again, please?

BY MR. REHWINKEL:

Q Let me ask it a different way.

Will you agree with me that Duke today, in this case, stands in the shoes of Progress Energy for all relevant actions that occurred related to this Bartow steam unit?

A Yes.

Q Can you tell me when you first had the responsibility of overseeing the Bartow plant?
A It was at the beginning of 2012, when I first actually assumed the position I am still currently in. So just about eight years ago. Prior to that, I wasn't directly involved with the operation of the Bartow site.
Q Okay. So when you said the beginning of 2012, you mean you were a Progress Energy employee?
A Yes, as a Progress Energy employee.
Q Okay. And tell me what your role was.
A In January of 2012, I became the vice -- we made some organizational changes at the beginning of 2012 while we were still Progress Energy in anticipation of the merger. So prior to that, I was in our nuclear generation group during the year 2011, but in anticipation of the merger closing, we did some reorganization, and I became the Vice-President of Generation for the Florida region --
Q Okay.
A -- the fossil generation and not nuclear.
Q Tell me when your first time was having a role or responsibility in the Bartow blade failure RCA process?
A When we first found the issues in the spring of 2012, and we needed to know what the causes were.

It's a significant issue. And so under my direction, we started what became a very long root cause because we kept learning more as each iteration of failure occurred.
Q Okay. Can we agree that when I make a reference to a period like 1, 2, 3, et cetera, that you understand them to be many as they are defined in the first two rows in Table A on page five of the Duke RCA?
A Yes.
Q Okay. So you were with Duke and had executive oversight over the plant during Period 1, is that right; during the very last few days of Period 1?
A That's correct.
Q Okay. And I think you just said so, but I want to make sure I understand. You were the person responsible for initiating the RCA process that we are talking about here today?
A That's correct.
Q Okay. And would that also mean that you were the person most responsible for assigning the employees to conduct the RCA process?
A I had an overview of that, and I could weigh in on the team makeup, yes.
Q Okay. Now, I think you said in -- before to me that for the RCA team that was -- for the RCA process

that was conducted after Period 5, you did assign the members of the team that responsibility with you, is that right?
A I didn't specifically assign the people. I could have modified the group. I had input into the team members. I don't remember specifically assigning the individuals.
Q Well, let me ask it this way: Isn't it true that the responsibility for assigning the members to the team --
A Yes, sir.
Q -- was yours?
A That's correct.
Q Okay. Was that true just after the March 2017 events, or all throughout this long RCA process?
A All throughout.
Q Okay. Now, I think in your testimony you mentioned a long-term solution team, is that right?
A Yes.
Q And it's fair to say the long-term solution team and the RCA team worked somewhat in concert through the process, at least since Period 5; is that right?
A That's correct.
Q And would you have had the responsibility of assigning the members to both the RCA and the long-term

solution team?
A Yes.
Q Okay. Throughout the RCA process, going back to 2012, would it be fair to say that you did review and provide edits to some of the drafts in the process?
A I know I reviewed some. I don't recall if I provided edits.
Q Okay. If I saw a draft that had the initials JRS on either a comment or an edit, you are the only JRS that would have been allowed to make edits to those documents; is that right?
A I don't know if I am the only one, but it's likely me, yes.
Q You didn't give me names of anybody in the root cause team that had the initials JRS, right?
A Not that I recall.
Q Okay. Would it be fair to say that even though the engineers that were primarily associated with the RCA worked for what you called Duke's central engineering, in this project, they had at least a dotted line responsibility to you in the RCA process in that you were the highest Florida Power generation executive in charge of the Bartow project?
A Yes, that's fair.
Q And you would agree with me that the draft

documents that were provided to the Public Counsel as a result of late filed Exhibits 4, 5 and 6 of your deposition constituted a part of the work product supporting the document that is JS-2?

A I am not sure I understand your question.

Q Okay. Let me break it down.

You are aware that you -- that as -- at your deposition in August 30th, the Public Counsel asked for -- in various ways, we asked for the draft documents that preceded the Duke RCA, is that right?

A Yes, sir.

Q Okay. Would you agree with me that those draft documents, and the documents that we received in Exhibits 4, 5 and 6 constitute, at least in part, the work product that supported the RCA that you finally produced?

A Yes.

MR. HERNANDEZ: Your Honor, could the witness see the documents?

THE COURT: It might be helpful.

Do you have a clear recollection of what he is referring to?

THE WITNESS: I don't. There were a lot of documents involved with the root cause, so I don't know that I have -- I know specifically.

THE COURT: It might be helpful to put those in front of him.

MR. REHWINKEL: Okay. I was asked to bring eight copies, and I have distributed all my eight copies, so I --

THE COURT: Let's see what I have up here.

MR. REHWINKEL: The documents I am referring to are exhibit -- what we identified as Exhibit 115.

MS. BROWNLESS: Charles, you can have --

COURT REPORTER: You can use mine.

MR. REHWINKEL: Okay. This will be the official copy.

BY MR. REHWINKEL:

Q If I may. So this is the summary of the synthesis.

A This one here is?

Q Yes, and then this is Exhibit 4, 5 and 6.

MR. BERNIER: And those are marked, okay, in our version?

MR. REHWINKEL: Yes.

And just for the record, Exhibit 115 is a culling of the root cause drafts that were taken from Exhibits 4, 5 and 6.

MR. BERNIER: Okay. Does he have 116 so we

can mark that for him?

MR. REHWINKEL: Oh, yeah. It would be in here.

MR. BERNIER: It would be right here.

MR. REHWINKEL: Yeah, this is 116.

MR. BERNIER: That way you don't have to mark it later.

THE COURT: Let me see -- okay.

MR. BERNIER: Which ones should he be looking at?

BY MR. REHWINKEL:

Q Oh, I am sorry. I thought you were reviewing. Your counsel asked if you could look at the documents.

A Okay. So I have reviewed it. I am familiar with what you --

Q Okay. So the question -- I think you answered it, but given that the objection came in, if I could just make sure.

Those documents that you reviewed in Exhibits 102, 103, 104 and 115, with the understanding that 115 is culled from 102 and 103, would you agree that they constitute a part of the work product supporting the Duke RCA?

A I would.

Q Okay. Would you also agree with me that the

documents in those four exhibits, 102, 103, 104 and 115, were retained as a matter of company practice?

A I think that is our practice, yes.

Q Okay. Would you agree with me that an engineer named Jake, Jacob or Jake English was designated to be the primary author of the Duke RCA?

A I would.

Q Okay. Would you also agree with me that he was the primary custodian or keeper of the documents that supported the RCA?

A Yes, I would.

Q Okay. Now Mr. English, you would consider him also to have been the lead author of the RCA?

A Yes.

Q But that didn't mean that he made all the analytical decisions, is that correct?

A That's correct.

Q He would be sort of like the engineer with the pen, is that fair?

A Well, Mr. English is more than that. He is --

Q I don't mean he is the scribe. But he was the one that was -- well, I will withdraw the question.

He was not the one making all the decisions. He was contributing to it, but somebody had to keep the record; is that right?

A He was one of multiple contributors, but he is the one that was the main author.

Q Okay. Other engineers, including yourself, were contributors to the RCA, is that fair?

A Yes.

Q Is it also true that non-engineers, including attorneys, reviewed drafts at some point throughout the process?

A Yes.

Q And RCA -- the Duke RCA was the only RCA, final RCA report that was produced throughout this whole process, is that correct?

A It was the only Duke Energy product.

Q That's what I mean. It was -- on your side of the fence, it was the only product that Duke finalized in this -- I think you referred to it before as a big, long root cause analysis, is that right?

A Yes, that's accurate.

Q Okay. Do you have a copy of your JS-2 with you?

A I do.

Q And we can do this. I am going to ask you questions from Exhibit 115, and just -- I should clarify something about 115, if you don't mind, Your Honor.

There is a table of contents. And the first

document actually is JS-2, and then I have put Documents 2 through 18 in here, and I have extracted -- I have included a screen shot at the back of this exhibit of the Duke file names that we were provided electronically, and I have extracted -- they say Bartow RCA white paper, pretty much, but there are some distinguishing features such as the date of the file or the author of it on this; do you see that?

A I do.

Q But you would agree with me that -- I mean, JS-2 is not a draft, it is the final document?

A Yes.

Q And if I could ask you to look back at Document 18. And this handwriting up at the top of each document is mine. It's not Duke's.

Would you agree with me that February 6th, 2018 draft, it has a watermark of draft on it, but this document is, in all respects, identical to the final document; is that right?

A I would really have to do a page-by-page turn to determine that.

Q Okay. But would you accept my representation it is the same document? It's the same date.

A It is the same date. I see that. So it's likely the same document, yes.

Q Okay. So maybe the easiest thing to do would be just to ask questions about the RCA in this document, because I am going to attempt to ask you questions going back and forth between the final and some of the drafts.

So if I could take you to Document 1 -- and one other thing, if you don't mind, as we work through this. In the bottom right-hand page of this Exhibit 115, we have a Bates number OPCCR -- RCAEXH dash, and then have the numbers. And those numbers correspond on the table of contents to the documents.

The Bates numbers in the upper right-hand corner are Bates numbers that we gave the late filed Exhibits 4, 5 and 6 because they came to us un-Bates, do you understand that?

A I think so. Yes.

Q All right. We don't need worry about those numbers up there. I am only going to be asking you about Bates numbers on the lower right-hand.

A I understand.

Q Okay. All right. So back on my questions.

On page two of JS-2, is it fair to say that the second full paragraph, starting with the word "based" is the ultimate conclusion of this RCA?

A Yes, it is.

Q And if we look on page 15 of the RCA, that

paragraph is just repeated under the word conclusion, is that right?

A Yes, it is.

Q Would you mind reading that aloud for the record?

A Based on its observations and study, Duke has been and remains of the opinion that the root cause of the failures in the steam turbine L0 40-inch blades is the blade design, lack of blade design margin. That is to say, under expected operating conditions at Bartow's 4-on-1 combined cycle unit, the MHPS blades are substantially more fragile than similar 40-inch blades both in Duke's combined cycle fleet and elsewhere in the industry.

Q Throughout, when we see MHPS, that's Mitsubishi, right?

A Correct.

Q Okay.

A Mitsubishi Hitachi Power Systems.

THE COURT: And OEM in this context also means Mitsubishi, right?

THE WITNESS: It does. Original equipment manufacturer.

THE COURT: Okay.

BY MR. REHWINKEL:

Q So in this RCA document, with this conclusion, Duke lays all the blame on Mitsubishi and assigns none of the blame to itself for the way the legacy Progress organization operated the plant in the first period; is that right?

A I think it's very clear we believe that the lack of blade design and the lack of margin in the blades is the root cause of all the failures of the blades.

Q Okay. Now, we discussed the period naming convention a few minutes ago. Under that Period 1 would generally be from June of 2009 to March of 2012, is that right?

A Yes, sir. That's correct.

Q Okay.

A And there is an easy reference for that on page five --

Q Right.

A -- Table A.

Q Would it be most accurate to say that the beginning of commercial operation of the Bartow plant and the steam turbine was approximately June 1st, 2009?

A I don't know if it was June 1st, but I know it was the months of June.

Q Okay. And is it further true that the end of

Period 1 was actually February 28th at 2:00 a.m. in 2012?

A Subject to check, yes. That sounds like when we would start an outage. Typically, we start when customer demand is low, and it was a planned scheduled outage we started at nighttime.

Q So isn't it Duke's position today that the company did nothing wrong in the way it operated the steam turbine during the first period?

A It is.

Q Is it also true that you have effectively asserted that even if you somehow operated the plant improperly with excess steam flow and high back-end loading on new L0 blades that you only did so because you were just not aware that you were doing anything wrong?

A We operated according to the parameters provided by the original equipment manufacturer, so I'm are not sure -- it seemed like there was two different -- a statement and a question there.

MR. BERNIER: I am sorry, Charles, are you referencing anywhere in his testimony?

MR. REHWINKEL: I am asking about what his root cause analysis shows and doesn't show, so...

BY MR. REHWINKEL:

Q So does the conclusion that you just read from your RCA mean that Duke's position is that Duke did not operate the steam turbine improperly in Period 1 by introducing excessive steam flow in the low pressure turbine and imposing high back-end loading on the L0 blades, and thus, Duke's operation of the steam turbine was not and could not have been a root cause of the blade failures in Periods 1 through 5?

A It does.

Q Is another way of putting that that the RCA conclusion means that it is Duke's position that even if Duke did run the unit improperly in Period 1 by introducing excessive steam flow into the low pressure turbine and imposing high back-end loading on L0 blades that it did not know that it was doing so, and thus, any harm caused was not its fault?

A It's our position that we ran it in accordance with the operating parameters that were provided.

Q Well, isn't it true that Duke put excessive steam into the low pressure turbine during Period 1?

A It is not true.

Q Isn't it true that excessive steam and high back-end loading on L0 blades caused damage to those blades?

MR. HERNANDEZ: Objection, Judge. I am

objecting on the basis of vague. I don't know what excessive means.

THE COURT: Maybe we should be more specific.

MR. REHWINKEL: Okay.

BY MR. REHWINKEL:

Q Well, in the root cause analysis process, didn't Duke engineers decide -- agree that excessive steam flow was introduced into the low pressure turbine?

A Could you point that out to me?

Q Okay. Do you have exhibit -- okay, let's go to -- let's just look at -- let's just look -- if you could turn to page 75, which is Exhibit 9.

A In Tab 9 in Exhibit 115?

Q I apologize. Yeah. Tab 9, yes.

A And I am sorry, could you say the page again?

Q 75.

A Okay, I am there.

Q And would you agree with me that the file name for this document is October 5, 2017, and it says PBC comments? That will be Paul Crimi, C-R-I-M-I?

A Yes.

Q And if you look halfway down the page, it says -- would you agree with me that it says: After months of study, Duke Engineering believes the following to be the most significant contributing factors towards

root cause of the history of Bartow Unit 4S L0 events, and the first put bullet is low pressure LP turbine excessive steam flow?

A Yes, I see that.

Q Okay. So the Duke Engineering folks that were drafting these documents accepted at this point in time that there was excessive steam flow introduced in the low pressure turbine, isn't that correct?

A I do not believe that to be the case, no. This is a working document that these are -- this is a list of bullet points of things that could have caused the root cause, things that needed to be investigated or analyzed more.

So low pressure turbine excessive steam flow is one of multiple items. Thermal distress at the LP turbine exhaust. Pressure pulses during hood or curtain spray operations. Shroud fretting fatigue found through zone analysis. Loss of dampening, blade fitment, those are all potential causes.

In fact, it looks to me like the team was zeroing in on the more likely causes that needed more analysis, but this is not a final document, so I would not agree with your statement.

Q Well, Duke Engineering wrote this statement, that's correct, isn't it?

A It is.

Q And Duke Engineering used the term "excessive steam flow", right?

A They did use that term.

Q Okay. So they had an idea that there was too much steam being introduced into the low pressure turbine, right?

A I think they had an idea that that could have been -- that is a potential cause.

Q Okay.

A That -- to be really clear, Mitsubishi's conclusion at that point in time was that there was excessive steam flow to the low pressure turbine. That fact that Mitsubishi believed that couldn't be ignored, and so that was investigated and analyzed very significantly throughout the course of the long root cause. Ultimately, it's not the root cause.

Q Just turn over a couple of pages to page 77 within this same document. Well, let me withdraw that question and let me take you -- well, let me ask you this: Mitsubishi said that you were putting too much steam in the low pressure turbine in Period 1, right?

A Correct.

Q Okay. Is high back-end loading, is that the same as excessive steam flow?

A They are related, I would say. If you can picture the steam pipe going into the center of the low pressure turbine on the diagram, if there is too much steam flow going in the middle of the machine, and then it goes axially in both directions, that could lead to high loading throughout the machine, including the back end, which would be the L0 blades.

Q Okay. And when you talk about high back-end loading here, just to be clear, you are talking about the loading on the blades, not loading on the condenser; is that right --

A Correct.

Q -- the way it's being discussed here?

A That's correct.

Q Can you show me in the RCA where you affirmatively determine that the introduction of excessive steam flow into the low pressure turbine and resulted in the position of high back-end loading on L0 blades in Period 1 did not occur?

A I don't know that I can show you that in the root cause. I think the root cause document -- well, what I know is the root cause document examines likely causes, potential factors operationally and from a design standpoint, and essentially rules each one of them out, concluding that the blades were not designed

with an adequate margin for the application at the Bartow.

The root cause document, if we wrote in there everything that was not found, it would be an extremely long document, so I don't think I can point to what you just stated.

Q Well, you said that Mitsubishi said you put too much steam into the low pressure turbine, right, excessive steam?

A Yes, let me make sure, from a technical standpoint it's the pounds per hour per surface area on the blade that Mitsubishi was concerned about on the L0 blades. The units -- the engineering units are pounds per hour per square foot. And if you put -- you can calculate that number. It's not a measured number. But it's related to steam flow, but it has to do with the impact on the blade for steam flow on a certain surface area of the blade.

That was Mitsubishi's concern when we first had the issue. In fact, for quite some time, it was their concern, because the calculated pounds per hour per square foot of steam flow impinging on the L0 blades was higher than what their experience was. It wasn't higher than any limit. It wasn't exceeding any pressure limit. It wasn't exceeding any temperature limit. It wasn't exceeding any flow limit. It was higher than their experience, and that made them concerned. And so they concluded that there was too much steam flow that caused that higher loading on the back-end blade.

Q Well, specifically Mitsubishi said that running the unit above 420 caused excessive steam to impact the L0 blades, and that caused damage, isn't that correct? That's exactly what they said.

A Not really. The -- there is something we really need to talk about here.

So the 420 megawatts is the product of the generator. And as we have discussed, the electrical generator is coupled to the steam turbine. When you talk about a steam turbine, you talk about parameters like pressures, flows, temperatures.

The steam turbine is what is then spinning the rotor. The rotor is connected to the generator. The generator produces megawatts, or more precisely kilovolt-amperes, which then, in order to talk about the entire unit, it's very common in the industry. We produce megawatts. We produce kilovolt-amperes. So it's common throughout industry to talk in terms of the product that you are making to get a relative feel of the size of the unit.

So many times, people talk about sizes of

combined cycle plants by the amount that the generator can produce. The amount that the generator can produce is dependent on many factors that are separate, actually. There is many factors that are part of the steam turbine output, but there is other factors that are in play as far as what a generator could produce.

So there is really -- in technical terms, Mitsubishi wasn't saying you exceeded 420, that was it. It was always all about the pounds per hour per square foot of steam flow impinging that last stage blade.

Q Do you have a copy of Exhibit 116 in front of you?

A I know I do somewhere. Yes, I do.

Q Okay. And this is -- are you familiar with this document?

A Yes.

Q Okay. And it's dated March 18, 2015, and it says, Duke Energy Bartow Report of Telemetry Test for 40-inch L0, right?

A Correct.

Q And if we turn to slide No. 4. This is what Mitsubishi says in the last bullet point: Mitsubishi estimated the cause of cracking was overloading of LP section based on 450-megawatt operation, which is over the design point of 420 megawatts, correct?

A Yes, that's what it says.

Q And that's what Mitsubishi said pretty much consistently throughout with respect to Period 1, right?

A They did. They were technical discussions, and I can point to other documents where they really talked about the steam flow, in particular the steam flow per surface area impacting the last stage blade. The use of the 420 here is just really a proxy for that steam flow.

Q Okay. But this phenomenon that I just read in that bullet point is what you mentioned that Mitsubishi said was going on, that that's why the Duke engineers put it in their RCA drafts before the final result was -- the final document was produced; is that correct?

A I am sorry, I am not sure what you are asking.

Q All right. Let me ask it this way: Because Mitsubishi said what I just read in that bullet on page four of Exhibit 116, that's the reason why that item is in the document that we looked at?

A Right. I see what you are saying.

So more correctly, I would say because Mitsubishi was talking about the steam flow that I have been stating was an issue, that's why we looked at it in the root cause.

Q Okay. So it wasn't just something off the

street that you had to deal with that would have made the document long. This was a significant central contention of Mitsubishi, correct?

A Correct.

Q This being the excessive steam flow and loading on the blades.

A At this point in time. Remember, this is without Period 3, 4 and 5 information available.

Q All right. But a document that was drafted in October 2017 would have been after Period 5, right?

A Yes.

Q Okay. So I guess what I am asking is you didn't affirmatively study the issue of high back-end loading on the L0 blades and reach a conclusion on that. Instead, you found that you couldn't study it, so you removed it from the final RCA, is that fair?

A I don't know if that -- I don't know all the details of every single thing that the root cause team studied or didn't study, so I don't know the answer to that question.

Q Well, let's look, if you will, on page one of the RCA.

Would you read for me the last full paragraph, because I want to ask your understanding of what that means?

A Starting with, Duke also studied?

Q I am sorry, starting with the second to the last paragraph.

A Duke Engineering?

Q Yes.

A Duke Engineering concluded that there was no correlation between any one of the above-listed factors in the five failure periods. Notably, Duke was only able to study each factor independently based on available data. In the absence of one, blade telemetry, two, duplication of the factors in various combinations, and three, operation in varying but normal conditions, it is not possible to study how each factor relates to and interacts with any other factor, if at all.

Q So doesn't that say that with respect to the early contentions that were even included in Duke Engineering's drafts about excessive steam flow and high back-end loading on the L0 blades, that you were unable to study it, and thus, you could not make a correlation and include it as an RCA conclusion; is that right?

A I don't believe that's what that is saying at all, actually. I think what this is saying is the root cause analysis is looking at things that happened in hindsight. If you had the ability to vary some variables and keep some others constant and do

repetitive testing, you would be able to test out whether conclusions were valid or invalid.

Obviously, we couldn't do that. We are looking at data. We are looking at combinations of variables at specific points in time without the ability to change those. And that's what this paragraph is saying.

Q Well, let's go back to Document 9. It was written down in this document, and would you agree with me -- and we can go through many of these documents and see that this language, after months of study Duke Engineering believes --

A I am sorry, which page are you on?

Q I apologize. I am back on page 75.

A 75. Okay, thank you.

Q This -- after months of student, Duke Engineering believes the following to be the most significant contributing factors towards root cause of the history of Bartow Unit 4S L0 event. That language is replete throughout these drafts, would you agree with that?

A I would have to look at all the drafts.

Q Okay. So let's turn to page 123, which is Document 13, and we see halfway down the page there, same -- with the same bullet point, low pressure LP

turbine excessive steam flow?

A I do.

Q And then we could go to -- and that was dated October 12th, 2017, and you accept my representation that that's what the file name said?

A I do.

Q Okay. And then we see on 137, which is -- this is a document that appears to be dated the same day, but it has a different set of initials, BWM, is that Ben Meissner?

A Likely it is Ben Meissner, yes.

Q He is your Charlotte-based steam turbine expert, right?

A He is one of our subject-matter experts, right.

Q Now, this document purports to be his edits to the RCA draft, right, if the file name is correct?

A That's what it appears to be, yes.

Q And this has the same -- I mean, there are some edits here, but there is no edits to this -- this thing we are talking about, this comparable sentence, right?

A That's correct.

Q And then we go to Document 15, it's just dated 10/13/17. It doesn't identify who, but there is no --

the words are the same here, right?

A They are.

Q Okay. And then if we go to Document 16, this is dated 10/17/2017, we see the same verbiage, right?

A I am sorry, which page?

Q I apologize, page 165. This is Document 16.

A I seem to be missing that page from my copy. That tab 16 starts, unfortunately, with page 167.

MR. BERNIER: I will show him mine, Charles.

THE COURT: I'll check mine. To cut to the chase, this is 165.

THE WITNESS: Yes, it says the same thing.

MR. REHWINKEL: Okay. Thank you.

THE WITNESS: Thank you, Your Honor.

BY MR. REHWINKEL:

Q All right. And then we have a differently styled, but on Tab 17 at 179, we see the same language; is that right?

A Yes.

Q Now, if you turn over to Tab 18, this is the RCA draft that we agree that, in all likelihood, is identical to the final, right?

A Yes.

Q That sentence, that phrase falls out. It's not in the corresponding portion of the RCA; is that

right?

A That's correct.

Q Okay. So between October 2017, assuming this file date is correct, and February 6, 2018, we have no draft documents, but that falls out -- that meaning the statement that Duke Engineering believes the following to be the most significant contributing factors toward blade failure, et cetera, that concept is not in the filing document; is that right?

A It is. I think you are making an assumption that each of these documents you are referring to are drafts of the final root cause, and I don't believe that to be the case. Now, I don't know -- again, I don't know all the details of what the root cause team was doing during the long period of time they were working, but if you examine what you are showing here in all of these Tabs 9 through 17 and compare it to 18, there are many differences between all those working documents and the final root cause analysis, and you just happen to be pointing to one of many, many differences between working copies and the final root cause document.

Q Okay. Well, let's look at page 188, which is in Document 17, and this -- it says Appendix A, Bartow L0 Event Summary, right?

A It does.

Q Now, in the root cause, it's called Table A, on page five, right?

A It looks to be very similar to, if not identical, to Table A, yes.

Q Right. They are not identical.

A Okay.

Q This table -- Appendix A and Table A appear to be -- have common genealogy in this process, right?

A Yes.

Q All right. So I don't understand now your assertion that documents 2 through 17 are not drafts of the final RCA?

A I -- what I am saying is I don't know if they are or not, but to me, it does not appear that they are. There are so many differences between 2 through 17. And then when you compare it to how the root cause on Tab 18 reads, there are many, many differences.

I would classify all these documents as working papers that summarize what the root cause team is doing; what they are finding; what they are analyzing, but it's not a draft of the root cause, in my opinion.

Q Well, let's go back to Document 3, and it's dated -- it's on page 23.

A Okay.

Q It's dated June 26th, 2017, do you see that?

A I do.

Q Now, if you turn to page 25, we see a comment by JRS1, is that you?

A It is me.

Q Okay. So it would be fair to assume that you reviewed this document?

A Yes, sir. That's correct.

Q I mean, you wouldn't just review this one little paragraph here. You would have read the whole thing, right?

A That's right.

Q Okay. So this indicates -- and if we go to page 27, we see an early version of Appendix A, right?

A I see that.

Q Okay. Now, is it your testimony here today in court that this is not part of the process that developed the RCA?

A No, it absolutely is part of the process.

Q Okay. So let's go over to Document 6 now. I have included Document 6 in here because there on page 49 to 58, there were some stray documents that were in the file that was submitted, and I want to ask you if you are familiar with or recognize the document on page 49?

A I am familiar with the information. I don't know -- I can't say whether I saw this document before or not.

Q Is it fair to say that this document is sort of a template for how to put together the root cause analysis that you are going to be producing through this technical paper process?

A I really -- again, I don't know the details of how the root cause team decided they would gather information and make a final report. I can read it and tell you what I think if you can give me a minute, but I really don't know.

Q Well, if we look at -- let's just look, if we can, the top line says Bartow 4S root cause analysis and evaluation of contributing factors, right?

A Yes, it does.

Q That's kind of what you would do if you were going to get a root cause analysis process under way, right?

A It is. It's also something -- notes of the team, things that they need to analyze and investigate, absolutely.

Q Okay. And it says a little bit down there, brief history, copy/paste and add to what Ben wrote in his summary to Jeff Swartz/Tony Salvarezza, 3/29, right?

A Yes.

Q So this is -- this -- Ben, again, is probably Ben Meissner?

A Yes, I agree.

Q All right. And he wrote you a memo, I guess on March 29, we don't have it, but obviously there was something that probably explained what had happened from the steam turbine expert's point of view?

MR. HERNANDEZ: Objection, Your Honor, calls for speculation.

THE COURT: To the extent you know, Mr. Swartz, I mean, you can explain.

THE WITNESS: Yes, Your Honor.

I don't remember specifically what Ben Meissner wrote, but it appears he wrote some -- an email, a note, something pertaining to the steam turbine, yes. It's not surprising. He is one of our technical experts.

BY MR. REHWINKEL:

Q Right. So I don't know, and I can't represent to you that the next page, which is 51, which is a one-page document, that's dated 8/24/2017, is related or not to this document. Would you know? This document being page 49.

A If 51 is related to 49, is that what you are

asking?

Q Yeah, I don't know if it is. I'm telling you I put together stray documents that were in the same area of the file.

A It appears to me that page 51 is actually some notes from a meeting, a working meeting. And I do agree with you that on 49, it looks like they are starting to put together things that would go into how you might want to format a root cause so that it would be clear and understandable.

Q Okay. So going back to page 49, it says: LP turbine back-end loading greater than 15,000 -- I forget how to say that.

A Pounds per hour per square foot.

Q Okay. And does this talk about how this has had an effect or not on the unit across the different periods of operation, right?

A That's what it says, yes.

Q So it would be reasonable to assume these documents that were maintained by the company, that there was an instruction to evaluate this as a part of the root cause process, right?

A Well, it looks to me like they were starting to build what would be in a final report out. And at that section, it appears that they were planning on

having some statement on that subject.

Q Okay.

MR. BERNIER: Charles, I am sorry, could I ask you what the first word before draft is up at the top?

MR. REHWINKEL: It says "miscellaneous".

MR. BERNIER: Oh, thanks.

MR. REHWINKEL: I am sorry.

MR. BERNIER: That's okay.

MR. REHWINKEL: I think I had brackets around it.

THE COURT: Would this be a good time to take five?

MR. REHWINKEL: Yes.

THE COURT: We have been at it for a while and give Mr. Swartz and everybody else a stretch.

(Brief recess.)

THE COURT: I think we can resume, Mr. Rehwinkel.

MR. REHWINKEL: Thank you.

MR. BREW: Excuse me, Your Honor, before we start, just to save time, I circulated copies of the two exhibits that we may eventually get to. All the parties should have it.

THE COURT: Okay. Very good. I have it.

MR. BREW: And there is copies on the desk for the witness when he gets to it.

COMMISSIONER GRAHAM: Thank you.

MS. BROWNLESS: Excuse me, Mr. Brew. I don't see any exhibits. Oh, got it. Thank you, sir.

THE COURT: All these red folders, they all look alike.

MS. BROWNLESS: Yeah.

BY MR. REHWINKEL:

Q So, Mr. Swartz, are you saying that Duke did study the impact of high back-end loading on the L0 blades, or did you say because of what happened with the blade failures in Periods 3, 4 and 5, you didn't study it, you just took it out of the RCA?

A Well, I don't think I am saying either of those things. The loading is a calculated value. It's really based on Mitsubishi's experience with their fleet, and it's a parameter that Mitsubishi just uses to help look at what is the forces -- what are the forces on a turbine blade.

You know, as far as studying that, again, with hindsight, you can only look at what happened. You can't run experiments to try to determine if you run a certain amount of steam flow, you will get a certain response. In fact, you may not want to run that. So, you know, I don't think it's either of the choices you gave me.

Q Well, did you study whether the introduction of excessive steam flow into the low pressure turbine and the resulting imposition of high back-end loading on the L0 blades was not a significant contributing factor to the root cause of the L0 blade failures?

A I believe that was considered as -- I mean, it's obvious in all these documents that the root cause team considered that as a potential cause. The steam flow -- what's the exact wording? Let me read it exactly here. Excessive steam flow.

The turbine parameters, the operating parameters are pressures and temperatures. And pressures really are what dictate the flow.

What we are saying is that we did operate in accordance with the design pressures of the unit. Mitsubishi is saying that they are not disputing that, actually. What Mitsubishi is saying is that operating at those pressures ends up having a higher pounds per hour per foot square of loading on the back end on the L0 blade than what they are used to, and that that's unknown to them. It's uncertain.

In fact, there is certain documents. In fact, if you look at RAP-6, and even in Mr. Pollock's exhibit

attached to his testimony, it talks about how Mitsubishi is just uncertain of what will happen in that zone.

So it's not known. I think that actually lends credence to the fact that the lack of blade design margin is the root cause. It's uncertain. The margin is not built in, and when you look at what happened over each successive period of time, even with lower operating pressures -- and again, the pressures are what dictates the flow through the turbine. Higher pressure, you are going to get more flow through the turbine.

As we went from Period 1 through Period 5, it wasn't successively lower, because Period 3 we actually raised the pressure at first in order to do some testing. But then during that testing, we realized we had something called an avoidance zone and we had -- which we had to avoid during operation, but we put specific pressure limits in place to make sure that we didn't have vibration on the last stage blades.

And that's really the issue. Whether it's steam flow, whether it's hardening on blade -- on the snubber or the tip, the shroud; whether it's blade fitment. It may be too loose. That means that there is not enough -- there is too much tolerance, perhaps, between the snubbers and the Z-locks. All those things lead to vibration or flutter in the blades, which then

could cause a failure. And that's what we are trying to avoid. In fact, we did avoid that.

Again, I can't emphasize this enough. We found proactively four times that there were issues with the snubbers and with the Z-locks, and we were able to take the unit out of service, continue operating for our customers with the combustion turbine generators, but we took the unit out of service before that damage migrated into the blade itself, which that would have been a catastrophic failure that could have taken months or years, and many, many millions of dollars to fix. But we were able to avoid that because we found these issues proactively.

So, again, the steam flow is just one of a number of things that can cause vibration in a blade. And ultimately, the root cause is that there is not enough design margin in the blades to prevent that vibration from happening. Even Mitsubishi agrees with that in their later root cause, that the root cause in every period is too much vibration.

Now -- so that's -- that's what I think this is saying.

Q Mitsubishi doesn't agree that they designed a blade that caused a vibration in every period, do they?

A I am sorry, could you ask that again?

Q Mitsubishi doesn't agree that they had an inadequately designed blade that caused the vibration, do they?

A They are in agreement that high -- that flutter, vibration, was the cause of blade failures in each of the five periods.

Now, I think it's a debate whether or not the blade should have put up with the atmosphere at Bartow, the operating conditions at Bartow, pressures and temperatures, and able to vibrate without having damage or, you know, obviously they vibrated and had damage. I don't think Mitsubishi would ever admit to a design weakness.

Q Okay. I just wanted to make it clear, they didn't admit that they have an inadequate design, right?

A Correct.

Q Just along that line, the blades in Period 5, they are called Type 1 blades, right?

A Correct.

Q Were they identical to the blades in Period 1?

A There was one slight difference. They were -- so let's talk about type for a minute. The type of the blade is the, by far the most important thing. And could I -- could I stand up, Your Honor, again?

THE COURT: Sure.

THE WITNESS: So again, we have some other folks in here, too, but the type of the blade is the curvature of the blade, and it's really talking about this blade itself, which is the structure you are trying to protect. You don't want that to come apart. You don't want it to crack. All of our issues were either with this snubber at the mid-span, or with this shroud at the tip.

But Type 1 blades have a certain geometry of the blade and a certain manufacturer. Type 3 blades are different. I don't know the specific -- I am not a turbine engineer, but the curvature is different. The thickness might be different. It's a different style of blade.

When we went back to Type 1 blades at the end in Period 5, it's the exact same blade. It's the same snubber, and it's the same Z-lock with one small change. There was a change in the geometry, just a softening of the edges, so to speak, to prevent some potential stress riser spots on the Z-lock and on the snubber. And that was the only difference.

Both Mitsubishi and Duke Energy concluded that based on all of the different data that they saw from other periods, that those small geometry

changes would be helpful to prevent future failures of either the shroud, the Z-locks or the snubbers.

BY MR. REHWINKEL:

Q The snubber was in exactly the same spot on the Period 5 blade as in Period 1?

A Yes, it was.

Q Do you know whether the manufacturing was exactly the same from the Period 1 blades that were made sometime before 2008 and the Period 5 blades that were made in 2012?

A Well, when you say the manufacturing, what do you -- how do you define that?

Q Well, how they are made, who they were made by, and the materials in them, were they exactly the same?

A I know the materials are exactly the same. I know that they are Mitsubishi blades, so we are really relying on Mitsubishi. They are a certain definition. They are Type 1 blades, so for what I know, yes, they are the same blades.

Q But you don't have any personal knowledge that they were -- that the manufacturing process was exactly the same, do you?

A Not any personal knowledge, no.

Q Okay. And did you have any evidence that they

were exactly the same? Did you go back and compare the manufacturing process in Period 1 blades and Period 5 blades?

A Not to my knowledge.

Q Okay. When -- at any point during this L0 blade event process, did Duke ever change any of the components in the low pressure turbine other than the L0 blades?

A Not to my knowledge, no. It wouldn't be surprising -- I mean, when you say any. There's many components inside a steam turbine, and every time you open it up, there is probably some sort of sealing surface that has to be changed. So I don't want to be wrong on a technicality, but -- actually, Mr. Bernier has a picture that might be really valuable if I could show it.

Q Sure. Just to be clear, I am not asking you about whether there was any ordinary maintenance that you did that affected any other component. My question was, and I think you understood it this way, did you make any other changes inside the L -- inside the low pressure turbine as a result of what you found in any of those damage events?

MR. HERNANDEZ: May I approach, Your Honor?

THE COURT: Yes.

BY MR. REHWINKEL:

Q Do you understand that?

A I do. And to answer, we did not make any others changes, and I think I can explain.

So this is the actual low pressure turbine at Bartow. Again, the steam goes in the middle and travels axially in both directions. You can see the blades get bigger as the steam travels through the turbine because the steam is losing energy and it needs more surface area to spin the turbine.

What you can't see in this picture is that there is fixed blades, called diaphragms, that fit in between each of these rows. So when you encase the turbine, those diaphragms are fitting in between. So as the steam travels through these nozzles, or blades, to spin the turbine, the diaphragms then redirect the steam so that they impinge on just the right angle to get the most work out of these blades as they travel through.

So they work in the second stage. Then they are redirected through diaphragms here, and then again redirected through the third stage. They are redirected into fixed blades here and redirected into the L0 stage.

And I think it's pretty important to understand that each iteration we had, we were able to inspect this whole turbine, and there were no other issues with the turbine. There were no other issues with the diaphragms. It was only with the L0 blades. And it wasn't with the blade itself, it was with the snubbers and the tips. And we took the blades out of service before there was damage to the blade, which would be much more significant and could cause damage to the whole turbine if an L0 blade failed.

It's such a massive weight going at such a high speed, that if a blade itself failed, it would be catastrophic, and that's what we were trying to prevent, and we did prevent through this process.

I think that's good for now.

Q So beyond inspection, you didn't do any study that determined that the upstream blades, or the nozzles or any other components in the low pressure turbine were unaffected by the pressures that were imposed in Period 1?

A Oh, I would say we have a great deal of information from these iterative inspections we did. You know, it's unfortunate that we had do so many inspections. The regular maintenance interval on a turbine would be maybe 100,000 operating hours, or 80,000 operating hours. It would be measured in years before you actually open up the casing of a turbine and look at it.

Because we proactively worked to prevent a blade failure, we had opportunity to look at the whole low pressure turbine multiple times over five years. Every time you open up a turbine, turbine engineers were all looking at it, taking measurements, doing nondestructive examination, making sure we don't have any other issues.

It was a concern. If we had issues in the last stage of blade, maybe there is issues in other stages, and so we did extensive examination, but we did not find any issues with any other stages or rows of blades.

Q And you didn't put that in the RCA, because you didn't feel that needed to be in there, that you determined that the rest of the turbine was fine?

A I am not sure why we didn't decide to put that piece of information in, but it's very clear we had so many opportunity for that inspection, and I know we did not have any other issues.

Q So looking at page six of the RCA, do you see a discussion under the heading "Operational Factors Potentially Impacting MHPS Blades", and then it has a subheading, "Low Pressure (LP) turbine Excessive Steam Flow - Running In The Avoidance Zone", right?

A Yes.

Q And these three paragraphs here are basically how you disposed of the issue of excessive steam flow, is that fair?

A It is.

Q Okay. And there is a reference here to the -- it says in the middle of that first paragraph: Based on hindsight, MHPS Engineering claimed at the time of the first failure (Period 1) Bartow Unit 4S exceeded the back-end loading limitation of 15,000 foot pounds per hour squared, is that the way to say it?

A The way I say it. There is actually a couple different ways, but pounds per hour per square foot.

Q Okay -- by many hours, and that the MHPS 40-inch L0 fleet average for back-end loading was closer to 12,000, whatever that is?

A Right.

Q Okay. And you don't disagree with those factual recitations about those numbers, either the L0 fleet average or the exceeding 15,000 foot pounds per hour squared?

A Yeah. What that represents is Mitsubishi's concern. So Mitsubishi's concern was that we were up in the 15,000 range with these blades, but the Mitsubishi fleet experience with 40-inch L0 blades was closer to 12,000 pounds per hour per foot squared. And that's

what led Mitsubishi to conclude that, oh, it must be that back-end loading. So that's the concern that's stated.

I am not sure if I answered your question.

Q Well, do you disagree that you were operating above 15,000 foot pounds per hour squared in Period 1?

A I don't disagree with that calculation.

Q In fact, when you were at 450, you were more at, like, 17,000, right?

A I think that he is a good approximation, yes.

Q And you don't disagree that the -- you don't have any basis to disagree with the Mitsubishi fleet experience, right?

A That's correct.

Q Okay. So there is a statement in the middle of the next paragraph about how many hours in Period 1 you were in exceedance of the avoidance zone you talked about, right --

A Yes.

Q -- 2,466?

You agree with Mr. Pollock's testimony that for Period 1, you operated the turbine at, was it 2,972 or 73 hours above 420 megawatts?

A I do.

What's really important to understand about these hours and avoidance zone in Period 1 is they are back-calculated. This thing called the avoidance zone didn't exist until after the telemetry testing was done at the start of Period 3. And with the value gained from that telemetry testing, which then derived this avoidance zone, we said, well, why don't we look back at the other operating periods and see where are we operating in that avoidance zone during the other periods.

So it wasn't as if we were violating some kind of limit during Period 1. We back-calculated that we were in the avoidance zone for that many hours during Period 1.

Q Well, Mitsubishi never said that operating in the avoidance zone in Period 1 was a problem. They said operating above 420 in Period 1 was a problem, didn't they?

A No. See, again, technically, this is -- 420 is really a proxy for the 15,000 pounds per hour per foot squared, or maybe even 17,000 pounds per hour per foot squared, which is the calculated steam flow for the surface area on the L0 blade.

That was Mitsubishi's concern. It was not an operating limit. It was beyond their experience. It was an area of uncertainty and that they did not know

about, and so they said that's what they believed. There was too much steam flow in the last stage.

Q Mitsubishi didn't say that you operated in the avoidance zone in Period 1, and that was the problem. That wasn't -- that was your -- that was a construct that you put on your evaluation in Period 1, right?

A I am sorry, could you --

Q Okay. Mitsubishi established the avoidance zone from, was it Period 3 forward?

A Correct.

Q Okay.

A They established the avoidance zone for Period 3 with the blade vibration monitoring system that was installed with those new blades in Period 3.

Q So the avoidance zone was established for a prospective purpose, right, by Mitsubishi?

A Correct.

Q Okay.

A It was -- well, let me make sure we understand.

So it was installed to make sure that we didn't have any more issues, so we created -- Mitsubishi did testing, and we were able to gather data that showed if you run in a combination of inlet pressures and exhaust pressures in certain areas, the blades vibrate

too much, and so you need to avoid operating in those operating conditions.

And then we received guidance from Mitsubishi. They said, don't operate in those avoidance zones. If you have to ramp up or down through those zones of operation, don't spend time in those zones. Get right out of them. That was the guidance issued to make sure we didn't have an issue from Period 3 on. We still had issues even though we avoided the avoidance zone in Periods 3, 4 and 5.

Q Well, my question to you is that imposition of the avoidance zone was about going-forward operations, correct?

A Oh, yes.

Q Yes.

A But I think the avoidance zone and the steam flow can't be separated. The avoidance zone is related to the steam flow, this pounds per hour per foot squared, and that's what is being talked about here in the root cause.

Q By the same token, operating above 420 and steam flow can't be separated either, can they?

A They can be correlated. There are many different factors that determine what the generator can produce as opposed to the pressures and the flows and in

the steam turbine. So there is a correlation there, no doubt, but you can't just use a megawatt output of the generator to talk about conditions in a steam turbine.

Q There is a high correlation between the amount of steam flow that gets you to 420 and above, right?

A There is. I think to try to really simplify, Mitsubishi is saying that the steam flow, the 420 and above would produce steam flow that would be beyond their operating experience in a zone that they were not certain of.

Q Okay. In the RCA, would it be fair to say that your analysis did not look at whether steam flows for the approximately 3,000 hours you operated the steam turbine above 420 megawatts caused material lasting damage to the non-blade portion of the steam turbine, did you?

A Are you looking at a specific part of the --

Q No. I am asking you if there is anything in your RCA where you studied the number of hours that you operated above 420 to determine whether it damaged the low pressure turbine.

MR. HERNANDEZ: Judge, I am going to object on vague because I am not sure I understand what the question is.

MR. REHWINKEL: Your Honor, I am trying to understand what the RCA did and didn't do. And my question is: Did the RCA study the amount of hours above 420 to determine whether that had impacted the low pressure turbine? That's my question.

A I think even better than just looking at hours -- and I don't know if that was a detail that the root cause team looked at or not. I suspect it was a detail that they looked at, but again, the root cause team had knowledge of -- in fact, firsthand knowledge for many of the team members of inspections that were done at every iteration at the end of Period 1, at the end of Period 2, at the end of Period 3, at the end of Period 4 and at the end of Period 5 to look at each stage of blades in the low pressure turbine; to look at each of the diaphragms in the low pressure turbine.

We had nondestructive examination conducted during those times to conclusively say that there was no damage in the low pressure turbine other than the snubbers and the shroud tips on the L0 blades.

Q Do you have a copy of Exhibit 105 in front of you? It's revised DEF response to OPC POD 31?

A I do not have 105.

Q It should be in that package there.

A I have 102, 103, 104, 115 and 116.

Q Oh, look to your left there, the red folders.

I am sorry.

A Oh, I am sorry. I covered it with my pictures. Okay, I have 105.

Q Now, would you agree with me that 105 is a response to an OPC POD No. 31?

A Yes.

Q Okay. And it's Bates numbered in the lower right-hand corner, so I am just going to refer to the last four numbers there.

Could I ask you to -- well, first of all, look at Bates 6868. And given your tenure at Progress, you are familiar with this kind of document, are you not?

A I am, yes.

Q Okay. This is what you do -- you meaning the executives and operational folks -- do to go to the Board to get approval to initiate a project?

A Well, it may or may not be the Board, but it is part of the project approval process. And based on the dollar value, the total project cost, there are different levels of approval.

Q I said board, I meant senior executive team --

A Yes.

Q -- is that right?

A Yes.

Q So we see here on 6868 all the executives,

like Jeff Lyash and Bill Johnson, et cetera, you see their names and initials for approval, right?

A Yes, I do.

Q Okay. And if we go to 68 -- this is called a business analysis package, right?

A Part of this is, yes.

Q Part of it, yes.

A Yes.

Q And the business analysis package says, here's what we need to do for the benefit of the company and its customers, and here's what it's going to do for them, and here's what it's going to cost to do it in very rough terms, is that fair?

A Yes, that's fair.

Q Okay. And the senior executives look at that information and they give you a thumbs up or a thumbs down, right?

A Yes.

Q Thumbs up is all these signatures and initials here, right?

A That's accurate.

Q Okay. So when we look on 6875, which is just a few pages in, we see that there was, I guess, an analysis done for business as usual, and that was basically the recommended case to build Bartow; is that

right? If you look on the prior page.

A So we are looking at 6875?

Q 74 and 75, I should say.

A Oh, 74 and 75. And so, yes, looking at the alternatives considered, I know -- I am familiar with these documents, and there were multiple alternatives considered.

Q Okay. And on 6875, in the, it looks like the second full paragraph starting with the secondary market; do you see that?

A Yes.

Q Okay. This is part of what was the chosen solution, is that right?

A Yes, it is.

Q Okay. Can you read that paragraph for me aloud?

A Sure.

A secondary market 400-megawatt steam turbine was found. The use of this turbine was investigated and proved to be a very good fit for the 4 CT and 4 HRSG combinations. In fact, it provided more operating flexibility (see operational analysis detail below). In addition, the uncertainty in project schedule and cost was reduced.

Q Okay. So this is -- this document is what the

senior executives would have reviewed to give the approvals that we see back on 6868?

A It's a piece of that document, yes.

Q Okay. All right. So there was an expectation that at the time this was approved by executives, that you were getting a steam turbine that was 400 megawatts in output, right?

A I would be very careful to characterize the actual capacity of any of the pieces of equipment based on this document. This is not a technical engineering document. It is a, like you said, a business analysis package. It gives the relative size of part of the equipment that's going to go into an approximate 1,200 megawatt 4-on-1 combined cycle.

Q Okay. Turn back to page 6911. This is page 3 of 27 of an IPP, which is integrated project plan.

A Yes, that's correct.

Q Okay. And we see over here -- in 2008, what would have been happening with the Bartow project where an IPP would be reviewed and approved?

A As far as what would be happening, could you give me more specific --

Q Well, you saw the BAP was approved in 2006, so that meant you could go ahead and execute on whatever contracts you had to do and spend the money, right?

A Right.

Q And that was kind of your authorization to conclude the contracting, I guess, for the Tenaska plant steam turbine?

A Yes.

Q Okay. So in 2008, if this IPP is dated -- these approvals look like on page 6907 they are in March of 2008. What's going on here?

A Well, I am paging back towards the beginning of the document. I am not familiar with -- and this is a long time ago before I was directly involved, of course.

Q Okay. 6861 -- 6881 is the beginning of that IPP and business analysis package, is that right?

A Yes. Could you -- I am sorry, could you state your question again?

Q So if we look on page 6885, we see -- I think they are looking for an additional $18 million of funding?

A On 6885?

Q Yes?

THE COURT: On the recommendation --

BY MR. REHWINKEL:

Q On the recommendation there.

A I see that, yes. I see it. So that is likely

the purpose for this document --

Q Okay. We --

A -- you know, I don't know specifically, but what I do know is that the project was commissioned in June of '09, as we have previously discussed. It was well underway from a construction standpoint when this -- the date of this document. So it looks like they were looking for some additional funding.

Q Okay. And on 6911, which is where I wanted to ask you a question, we see Paul Crimi's name and his signature and a date, right?

A Yes.

Q Does that mean he was -- would have been involved in sort of the planning and implementation of the Bartow repowering project?

MR. HERNANDEZ: Objection, Your Honor. I think the witness is testifying he is not certain about this document altogether. He is not certain what's occurring here, and so there is a lack of a predicate for this question.

MR. REHWINKEL: My question is to ask him about Mr. Crimi, and I have a question later on that will tie this later on, Your Honor.

THE COURT: Again, I will overrule to the extent he can only answer what he knows. If he

doesn't know, I think he is capable of saying that.

THE WITNESS: Well, so if you look at the signature blocks required here, it's -- this is a big decision for the company. It's a lot of money being talked about, a lot of funding, and there is a lot of executives listed here from multiple departments. It's not just the department involved with the construction. It's not just the department that would be involved with the operation of the unit.

Mr. Crimi, at the time, was an executive with a support services branch of the company, and so he was one of the required signatures of many executives. Since it was a large financial decision, there had to be buy-in from an alignment across the executive suite.

BY MR. REHWINKEL:

Q He was Executive Director of Power Generation Services, is what it appears to say here?

A Yes.

Q Okay. So based on your knowledge of the company at the time, would that have meant he would have had some operational responsibilities with respect to the steam turbine and the Bartow repowering?

A Actually, no, it would not have. He was -- as power generation services, that's technical expertise. It's engineering. It's not the operation of the unit. The operation would be some of the other signatures on this page.

Q Well, obviously, it wasn't commissioned at this time. I am talking about as far as implementing the project, when I said operational.

A Well, and again, as far as implementing the project, this looks like every executive in every department in the company was part of the decision to implement the project since it was such a big investment.

Q So in 2006, you executed a contract to buy the steam turbine from Mitsubishi, right?

A Subject to check, yeah. I don't remember if it was 2006.

Q But in 2006, Duke contracted with Mitsubishi, as your documentation says, to perform heat balances, correct?

A Yes.

Q And could you tell the judge what a heat balance is and what its intended output is?

A Sure. Any big new project like a new power plant, you have to try to -- well, the engineering analysis includes looking at many, many variables, in

fact, a few dozen variables that can come into play to predict what the output of a unit will be.

There is different operating pieces of equipment that might be operating or not operating. There is different atmostpheric conditions. The temperature of the weather makes a difference. The temperature of the air makes a difference. The temperature of the cooling water makes a difference. The temperature of the cooling substance which might be hydrogen in the case of a generator. All these things are analyzed many different ways.

So, for example, on the Bartow combined cycle project, there were over 300 heat balance cases that were developed. And it seems excessive, there is over 300, but think about Bartow for a minute. It's a 4-on-1 combined cycle, so you might run a heat case that is with all four combustion turbines running and the steam turbine, so 4-on-1 operation, but without what are called duct burners running. And you might do that at 32 degrees. You might do it at 72 degrees. You might do it at 95 degrees ambient conditions.

And then each one of those ambient air conditions, you might do it at a different cooling water temperature, because all those variables make an impact on what the engineering prediction is going to be on the

gross output of the power block.

So for Bartow, you would do it on 4-on-1, 3-on-1, 2-on-1, 1-on-1 configuration. You would do it with duct burners, without duct burners in service, which is a very significant part of the operation that I haven't talked about yet.

In the heat recovery steam generator, I mentioned how the exhaust steam -- or the exhaust gases, rather, from the combustion turbines, rather than go out in the atmosphere, which they would in simple cycle operation, they are captured and they heat water, but there is also capability built into these heat recovery steam generators that they are called duct burners. The natural gas-fired burners will light fire literally in the duct to put more heat in addition to the exhaust gases coming from the combustion turbine so that you can generate -- turn more water into steam. Generate more steam from the HRSGs. So whether duct burners are on or off is a very significant variable.

In addition, at the Bartow site, there is something called power augmentation in the combustion turbines. And this gets pretty technical, but you can actually extract part of the steam as it's going through the steam turbine before it reaches the condenser and then pipe it into the combustion turbines to augment the

air and combustion gases that are turning the combustion turbines motor.

So you are putting some high pressure steam into the combustion turbines to make it generate more megawatts. You are stealing a little bit of steam from the steam turbine to do that, so whenever you use power augmentation in the combustion turbines, you turn on your duct burners to get more steam from the HRSGs to put back in the steam turbine.

THE COURT: Steam turbine, I got you.

THE WITNESS: So depending on what pieces of equipment are operating at Bartow, there is a great variation in how many megawatts the site is going to have as output. And so, like I said, over 300 different heat balance cases were generated as part of the project as engineering predictions on what the result would be.

BY MR. REHWINKEL:

Q So what is the primary output of a heat balance? Isn't there, like, a bottom line that comes out?

A There is a lot of output. I don't know that I can say there is a primary output.

Q Okay. Well, let's -- do you have a copy of Exhibit 108 in your red folder there?

A Yes, I have 108.
Q Now, this happens to be Mitsubishi's response to your RFP for the long-term solution, right, this document?
A Yes.
Q Okay. But if we -- if I could get you to turn, and I apologize I didn't Bates these, these Bates numbers at 2437, they are real tiny. If you go to 2435, you can see there is an electrical -- or there is a diagram, and then after that, I want to ask you something about the heat balances that are behind that.
MR. HERNANDEZ: So you want 437?
MR. REHWINKEL: Yeah, 437.
MR. BERNIER: It is small.
MR. REHWINKEL: Yeah.
BY MR. REHWINKEL:
Q Once you get into that area, you will see that there is an easier-to-read page 2 of 129, there is 100 --
A I think I am there.
Q You found it?
A Yeah.
Q Okay. And I apologize, I don't know why page 1 of 129 is not here. Our -- the document is Bates numbered consecutively, but I want to ask you if 2437 is

the output of the heat balances, one of the pages of the output of the heat balances that you just told the judge about?
A It is, and it's also on 2438, the columns follow down. There is so many variables involved.
Q Oh, yes.
A It's the same -- like, for instance, if you look across the top of 2437, this looks like it's Case 1 through Case 15 of the heat balance, and there is still more of Case 1 through Case 15 on 2438.
Q Well, go to 43, I think you will see at the bottom of that.
A And there is more on the page after that as well.
Q Yeah. Go to 2443?
A 2443.
Q Yeah. Is that where this -- these -- the cases are numbered across the top 1 through 15?
A Yes.
Q Okay. So these pages from 37 to 43, these are -- these all relate to the same --
A They do, yes.
Q -- long columns, right?
A Right.
Q Okay. And then we see on 44 there, there is a

whole new set of heat balances?
A Right, 16 through.
Q Okay. But let's go back to 37. And would it be fair to say that these are operating permutations, is that a fair way to say these are kind of postulated ways you could operate the unit, 1-on-1, 3-on-1, 2-on-1?
A I would say they are predictions --
Q Okay.
A -- based on varying different operating parameters.
Q Okay.
A And having different pieces of equipment in service or out of service.
Q Right, okay.
So when we look on -- in the bottom -- at the top a little bit, say, the top third of the page, we see on the left-hand side, run date, in the heading titles, right?
A Yes.
Q And if we follow that all the way across, it says 7 September, 2006?
A Yes, I see that.
Q Okay. So are these the ones that were done by Mitsubishi or by Bibb?
A I don't know, looking at them. I know -- let

me look up at the title. These appear to be the ones done by Bibb.
Q Okay. Now, Bibb is an engineer, or an engineering firm that you hired to run heat balances in conjunction with Mitsubishi, so you knew what you were going to be getting out of this unit before you finalized the purchase, right?
A Well, Bibb was a little bit more than that. That's a piece of their scope. But Bibb was the engineer on the project, so we -- we, Progress Energy at the time, had a contract with a consortium that was Bibb and TIC constructors that together acted as the engineer procuring construct contractors for the entire project.
Both of them later merged and were bought by Kiewit. If you know what Kiewit is, Kiewit was in the business of doing EPC projects for companies.
So Bibb acted as the owner's engineer, but that's -- so what you just stated is a piece of the service they supplied.
Q Okay. But it is true that Bibb was your guy -- I don't know if it's a person or people -- that's your guy that represents you and makes sure that the heat balances are run correctly and that Mitsubishi agrees with the heat balances, is that fair?
A I -- it's -- part of it I know is fair. I

don't about the Mitsubishi agrees piece. I don't know the ins and outs of how that's done in a large construction project.

Q Well -- okay.

So Mitsubishi -- didn't Bibb work with Mitsubishi to run these heat balances?

A I am sure there had to have been collaboration.

Q Okay. So let's look at -- above that run date, we see somewhere up in the mix, more than halfway up, it says STG output, do you see that?

A Yes, I do.

Q All right. And then in bold all the way across the page, we see variations of megawatt outputs under these heat balances, right?

A Correct.

Q All right. So these are -- it's bolded. This is a primary result that you are looking for out of the heat balances. It tells you what the bottom line is you are going to get out of this, you expect to get out of this unit under these predictions or permutations, right?

A It is one of many things that we are getting out of this, yes.

Q But like you told the executives when you said

400, that's kind of the bottom line when you get a steam turbine, is what are you going to be able to generate in terms of electricity to serve customers, right?

A Could you ask that again, I am sorry?

Q Yeah. When you are buying a steam turbine, the bottom line is what kind of megawatts can you get out of it, right?

A That's one of the -- well, the efficiency is one the Keys. In fact, I would say efficiency is even more key in a big project like this, because ultimately the long-term cost to the customer comes down to how efficient are you converting fuel energy into a product.

Q Right. So would you agree with me that heat balances were run and certain cases were selected and used for the contract that you determined -- that you executed with Mitsubishi?

A Yes.

Q There were two heat balances that were part of the contract guarantee that Mitsubishi said they were warranting the unit to put out?

A That's correct. I have seen other documents where two of these heat balance cases were chosen and were included in the contract language relative to liquidated damages.

Q Okay. And one of the outputs -- one of the

heat balances was 389, and that was a certain configuration, correct?

A I believe that's correct, yes.

Q And the other was 420, right?

A That's correct.

Now, a really important point here, you are picking one. Let's look again at how many pages of data is in each one of these heat cases. It's multiple pages, right? I won't count them, but at least five or six pages.

One of these -- for example, one of these variables is power factor. And I can't read it, I am having a hard time reading it. I wish I could point to the row. If I could get a magnifying glass, I could read it to you. But I have read through these before. I have looked at all 300 plus of these P cases.

The power factor assumptions are really key, because when you think about a generator, an electrical generator, the power factor of the electrical system has great bearing on what the generator is able to do.

So in each of these cases, there is an assumed value-of-power factor. And so for the assumed value-of-power factor in case number 48, which you are referencing, which ended up 420 megawatts of the steam turbine, it was at a power factor of .949. We don't run

at a power factor of .949. We run at a power factor close to one, which we call unity.

And this might be a good time, Mr. Bernier has a drawing, I could explain power factor, and I think this is quite important.

MR. HERNANDEZ: May I approach?

THE COURT: Yes.

THE WITNESS: And again, this is just an example of --

MS. BROWNLESS: Mr. Swartz, I am sorry, when you hold the paper up, I can't see.

THE WITNESS: I am sorry, I will stand up.

MS. BROWNLESS: Thank you.

THE WITNESS: There is so many variables, as you see in all these pages, that go along with these heat balance cases. All of them have an impact on the capacity of what the unit is going to run. So I am picking one that's called power factor because I think it's pretty important.

Power factor is a measure of the efficiency of how load current -- we produce load current from our generator, megavolt-amperes, all right. How efficiently can we make that -- I am not there yet. This is a donkey pulling on a barge. I will get there in a second. A efficiently we convert that load current into voltage, into real power, rather, is really important to us. It's really important to all of our customers. We want to do that as efficiently as we can.

So we have -- there is a measurement called power factor that measures that efficiency. We want to be as close to one as you possibly can be. A 1.0 power factor means you are being as efficient as you can converting load current into real work.

In the real world, there are loads. There is motors; motors at FIPUG; motors at PCS Phosphate that are creating a drag on the system. They are creating the system to do extra work.

But also in the real world, we have equipment that -- and that makes the power factor drop less than one -- to go down into maybe -- when I say less than one, I am talking decimal places. It might go down to .9 or to .95. But we have things on our electrical system that keep it up close to one called capacitor banks that are in service all the time, because we want to make that conversion as efficient as possible for the benefit of our customers.

So to make it real simple, power factor is just like in this picture. A power factor of one,

for this horse to pull this barge through the canal as efficiently as possible, the horse would have to walk on water, right, and be directly in front of the barge. If you are directly in front of the barge pulling it, the horse is going to have to do less work and it won't heat up as much to pull the barge.

The greater the angle becomes this direction, more of the work of the horse is pulling this way and less of it is pulling straight down the barge. And so the greater this angle is, as the horse is pulling the barge down the canal, the more overheated the horse might come because it's harder. It's harder work. The power factor is lower in that case.

So the generator is -- the analogy is to the electrical generator. The generators are rated by power factor as part of the rating, and there is curves -- and there is curves in a lot of this information that we saw that you can see based on power factor how much a generator is capable of putting out.

And these heat balances, the power factor was assumed to be various numbers; ..9 was used in many of the examples of heat cases; .949 was used in the

one you are referring to. Our system runs between .97 and .995 all the time. Our generator at Bartow can do more than 420 megawatts because it's closer to walking straight ahead of the barge. The 420 is at a power factor .949, which is not where we run.

So the 420 megawatts doesn't apply to the steam turbine. It's part of the generator, and our generator is capable of doing more than that because our power factor runs closer to unity.

I hope it made sense. It's an odd -- it's a difficult-to-understand electrical concept.

BY MR. REHWINKEL:

Q So none of the P balances that are shown in this exhibit, we call it 108, showed a expected output above 420, maybe 420.2, but nothing up to 421 or above, right?

A I didn't see -- they don't, but I also didn't see any power factors above .949.

Q Okay. You would agree that the contract contained expected megawatt output of 420 megawatts, correct?

A At an assumed set of conditions, including power factor, that is correct.

Q So at the time you talked to senior executives and contracted with Mitsubishi, both Mitsubishi and Duke

expected the steam turbine to put out 420 megawatts at normal operations, right?

A The expectation would be that the predicted heat case would be achieved.

So, again, let's be really clear. What Mitsubishi and the project team used, they used heat case number 48, which used a power factor of .949. It predicted a megawatt output of 420. They used that as the minimum thing that Mitsubishi had to achieve in order to get full payment on the project. Anything below 420, there would have been liquidated damages that Mitsubishi had to pay to Progress Energy.

So the 420 was actually a contractual minimum that had to be achieved. And again, it was at a lower power factor than we actually run at. So everybody would have known that the steam turbine generator can produce more than 420 megawatts.

Q Do you have Exhibit 116 with you still?

A Let me get organized here.

Q I would ask you to turn to page 21 when you get there.

A I do have 116. Page 21?

Q Yes, sir.

A All right, I am there.

Q Now, this is a Mitsubishi document. And do

you disagree that the Bartow steam turbine was designed to operate at 420 megawatts, as the OEM says?

A I agree that there is a case with certain variables, and you can see there is pages of variables that go in. And if the variables are at those particular numbers, then 420 is the predicted output. And that was used as a contractual minimum that Mitsubishi had to achieve.

Q Well, in the second bullet, it says a heat balance diagram providing max operation, parenthesis, 420 megawatt, thermal conditions was provided as part of the thermal kit. Do you disagree with that?

A That's what it says. And my interpretation of that is the maximum the generator can put out at those conditions at a power factor of .949 is 420 megawatts.

Q Okay. And then the next bullet there was -- it says: During the performance test in 2009, using the 420-megawatt thermal conditions, the unit was able to reach approximately 402 megawatts; is that right?

A That's correct.

Q And the performance test here was when you were installing the unit. Sometime before you commissioned it, you did a test to see whether it met the contractual terms as far as that guarantee, right?

A That's correct.

Q And is this factual?

A Yes.

Q All right. So let's go to Exhibit 109, which is the contract. And I want to go to actually attachment Appendix A.

A Appendix A?

Q Yes, sir. It starts at Bates 12419.?

MS. BROWNLESS: Excuse me, Charles. Just so I understand, this is the page that says Contract No. 270810, Amendment 005?

MR. REHWINKEL: Yes.

MR. BERNIER: Mr. Swartz, I think it's after the first divider sheet.

THE WITNESS: I found it. I am sorry. I just found it.

BY MR. REHWINKEL:

Q All right. So you agree with me, this is part of the contract for the steam turbine, right?

A I do.

Q Okay. And if I get you to go to Bates 12437. This is 3.3 Basis for Guaranteed Performance, as a header, when you get there.

A Okay, I am there.

Q Okay. Is this how the electrical output of the turbine was calculated? Is this the formula?

A It is.

Q Okay. And if we go over to 12439, just for the -- to follow up on your testimony about the power factor. We see those -- this is what you were talking about -- power factor is .9 and .949?

A It is. On that -- the table in 4.2, you can see those in the third row down in each column.

Q Okay. And they also have condenser back pressure assumptions that correlate to those outputs, is that right?

A Yes.

Q So -- and we see that -- is it true that the Case 28 was a 4-x-1 configuration, and Case 48 was a 3-x-1 configuration?

A Case 28, to my memory, was a 4-x-1 without duct burners. And Case 48, to my memory, was a 3-on-1 with full duct burning.

Q Okay. Does this document here, or the heat balances, or any other documentation that you can point to demonstrate that Mitsubishi or Bibb told you that you could get more than 420 megawatts of output from the steam turbine?

A Well, I believe you can look at some of this documentation and reach that conclusion, yes.

Q Because of the power factor?

A Yes.

Q Okay. But did anybody tell you that it would be perfectly normal to operate the unit above 420 megawatts per -- as much as you wanted?

A That's not a typical conversation. So the Bartow combined cycle, just like any other project, you talk about what the capacity is you are going to get out of the site. And in this case, I think some of the documents referred to a number maybe 1,278 or 1,279 megawatts, something like that. But there are many, many variables that come into play as far as the output of your machine. In the wintertime, when it's colder, when the cooling water temperature is lower, we can run with better condenser vacuums much more efficient.

So to give you an example, our Duke Energy Florida fleet, in the summertime we can produce about 10,000 megawatts of power. In the wintertime, we can produce about 11,000 megawatts of power. And the difference is the colder weather, the colder cooling water that helps the machines be more efficient in the wintertime.

So you have to make sure you are understanding. Every time you are talking about a rating of a piece of equipment, you have to understand all the other conditions that are part of that predicted rating. And it would be a really bad thing to say you have to adhere to this one case out of more than 300 and never exceed that because you would be leaving potential capacity on the table that could be used for the benefit of our customer.

So let's expand Bartow, the Bartow is a steam turbine. You know, Bartow is a 1270-megawatt site. The steam turbine is, you know, 400, 450 megawatts, somewhere in that range. But it's different in the summer than it is in the winter.

But if we were to apply, say, summer ratings, and then in the wintertime, when we need 11,000 megawatts to serve our customers, we would have to buy expensive fuel, or we would have to put on less efficient generating units to great expense for our customers.

So you have to understand all the variables associated with a rating. Our job as operators is to make sure we stay within the operating parameters that are given by our equipment manufacturers and get the most out of our machines that we can without exceeding those parameters. And that's what every operator does. That's what every utility should be doing, and that's certainly what we did with Bartow.

And there is one more thing I would like to say. So to answer your question directly, if you go to page 12596 in this same document. It's way back there. It looks like this.

MS. BROWNLESS: What's the number again, sir?

THE WITNESS: In the lower right-hand corner, it's 012596.

So, Your Honor, are you there?

THE COURT: I am there.

THE WITNESS: This is the capability curve of the generator for this project. And this is the page that shows that you can get more than 420 megawatts if the power factor is greater than .9.

And I know this is hard to read, but this line right here going up at a positive angle is a .9 power factor line. And you can see it intersects the generator capability curve. If you come down, you see that's right at 420 megawatts.

We run closer to unity, closer to one. And if you go all the way across, that's almost 470 megawatts. And if you look up at the very top of this piece of paper, you can see there is a rating up at the very top. It says 468000 kVA, that's kilovolt-amperes. That's the reactive power

that this generator is capable of putting out. Power factor is the kilowatts divided by the kilovolt-amperes.

So you can see the kilowatts is only 420.2 -- 421.2. It's 421,200 kilowatts. So it's 421.2 megawatts. But with a power factor closer to one, you can get closer to 468 megawatts out of this steam turbine. That's what that information is telling you. So in the same document, they are saying you can get greater than 420 megawatts.

BY MR. REHWINKEL:

Q So 468, is that approximately the rating of the generator?

A Correct.

Q Okay. So --

A The -- well, kVA, to be more precise. And it depends on the power factor, and whether or not you can get that much megawatts, the real power out.

Q So is it Duke's position that as long as you stay within the IP, HP and condenser limits, that if you could get to 468 on a regular basis, that you would be -- it would be perfectly okay to operate -- have operated that unit in 2001 -- Period 1? I am sorry.

A Right. You have to look at other parameters as well. Again, it's hazardous to look at just any one

parameter, but this gives you an idea of what the capability of the generator is.

So we have a piece of equipment attached to the steam turbine that's capable at the power factors we run of doing in excess of 460 megawatts. So as long as we can stay within the operating parameters of the steam turbine, and those are pressures and temperatures, why don't we try to get as much output from the generator as we can.

Q Do you have Mr. Pollock's exhibit RAP-5 with you?

A I do. Okay, I am there.

Q You got that, okay.

And this is a document you prepared at our request, the Public Counsel's request, right?

A Yes.

Q Okay. So there is no question about the validity of this data, and accuracy of it, right?

A I will say I know that there is -- this is -- it uses averaging. And it depends on how often you sample a data point, and that can cause discrepancies in the data. It's a good representation, I will say that.

Q Okay. And this document here is what Mr. David referred to in his opening. It has the operating hours above 420 as distributed on this chart, is that

right --

A Yes, it does.

Q -- with that approximation caveat?

A It does.

Q So I just wanted to ask you about this, because as you were talking about being able to increase the output based on certain efficiencies, including ambient temperature, weather, right? And what I mean now, I am talking about the air temperature and the water temperature, right?

A Sure.

Q Let's look at period of 2010. Would you agree with me that -- and would you also agree with me that the months of June through September are your hottest months?

A I would.

Q Okay. And we look at here, we see a fairly large distribution of the operating time above 420 in the hottest months, right?

A Yes.

Q Okay. So it wouldn't necessarily be a reasonable conclusion to suggest that you operated this high above 420 -- or this much above 420 because the weather was colder, right?

A Well, you have to understand what else is

going on at the plant at the time. So our ability to pump that cold or warmer water through the system is really important. You are not going to get the efficiency unless you are able to pump it.

And what I know is when we first commissioned this plant, and during the first several months of operation -- and I don't know how long it went into 2010, but we had some great difficulty with what's called the circulating water system, which circulates the cooling water through the equipment, including the condenser underneath the steam turbine.

My conclusion from this data would be that once we straightened that out and were able to fully pump water through the condenser, we started really taking advantage of what we could from an installed equipment standpoint. Also understanding that in any new operation, there is a period of learning for the operating staff as well. But I know we had these equipment issues with the circulating water system for the first several months of operation.

Q But in 2010, there is not -- in fact, it looks like you have more hours above 420 --

A I think --

Q -- in the hot months than in the cooler months, right?

A Right, because I think in the cooler months, we were still having trouble with the circulating water system. I don't know that, but --

Q Okay. And before 2012, you did not do an engineering analysis that showed that it was possible to operate the unit above 420, did you?

A Well, I think we had all kinds of information that showed that it was possible to operate above 420. In fact, if we could, let's refer back to the contract for a minute.

I will have to find the exact page, but again, the 420 megawatts that you keep referencing was a contractual minimum that Mitsubishi had to meet in order to get full payment on the project. So just that fact alone tells everybody that above 420 is okay. 420 is the minimum that had to be achieved. And that's in this contract. I will just have to -- if you give me a moment, I will find the page.

Okay, so if you turn in the -- let me see what the exhibit number is. It's the contract. It's the very large document, Exhibit No. 109. And if you turn to the Bates numbers 012434 in the bottom right hand. Well, it's even better if you page to 12432, which is two pages before that, 12432.

And you can see in paragraph 3.2.1 that the

420.07 is a liquidated damage performance guarantee, which means that's the minimum that the project had to achieve in order to get full payment on the project.

Q But it says in 3.2.12: MPS Net Steam turbine Maximum Electrical Output 420.07, right?

A Yes, that's referring, in my opinion, to that generator capability curve that I just showed you. It's at a lower power factor than we operate. So again, you have to make sure any time you talk about a rating, you have to make sure you understand all the variables that go into that rating. In this assistance, it used a power factor that we can far out achieve.

Q Okay. So in 2012, after you had the first discovery of blade damage, isn't it true that you went to Mitsubishi and asked them for their help in telling you how you could operate above 420?

A I would phrase it a little differently than that.

So we opened up the steam turbine for a routine inspection in the spring of 2012. We found five of the mid-span snubbers that had damage. We were concerned with that. So we consulted with Mitsubishi. They recommended we don't continue running with those snubbers broken. That could lead to blade failure, which would be catastrophic, as I have described earlier.

At that time, Mitsubishi, as we've seen and you pointed out, they were concerned we were running higher than their fleet experience from a pounds per hour per square foot standpoint in the last stage blade, so they gave us, for the first time, a lower operating limit.

And in this case, if we could turn to my -- to JS-2 in the root cause, I can show you what the operating limit is. It's page 5 of 18, Table A in JS-2, or JS-1.

Are you there, Your Honor?

THE COURT: I am just about there. Yeah, I am there now.

THE WITNESS: Okay. So in that table, you can see it has columns for each of the five periods. And the one, two, three, four, the fifth row down says MHPS IP exhaust pressure operating limits.

So it's at the start of Period 2, because of that damage we found, following Mitsubishi's recommendation, we replaced all of the blades on just one end of the machine because all five snubbers were damaged on the same end of the machine, I believe on the turbine end. It says in this chart. I am not looking at it.

And if you look at the picture over here, you can see that the machine has two ends. The generator is coupled to the right-hand side, and the HP IP turbine is coupled to the left-hand side. So on the turbine end of the machine, we replaced all 64 L0 blades.

Before we started operating again in April of 2012, Mitsubishi, in order to make sure that we didn't exceed their operating experience with 40-inch L0 blades, they put this 118-pound limit on the intermediate pressure turbine exhaust. And in this case, that served as a proxy.

Why that intermediate pressure exhaust rather than the low pressure turbine inlet. There was no pressure instrument on the low pressure inlet, but there was one on the intermediate pressure exhaust, so that was used as a proxy.

And if I could stand up just a minute just to make sure everyone understands. Mitsubishi was concerned, as I described, with the steam flow, but there was no pressure instrument on the pressure going into the low pressure turbine, but there was one coming out of the intermediate pressure. So there is just a slight amount of pressure drop across this pipe.

So we used this pressure as a proxy for the low pressure turbine inlet. It was more conservative than what had been in the past, so the combination --

And I am sorry, but I forgot what your question was, but, yeah, we put a more conservative operating limit in place based on pressure, which is consistent with operating parameters that we followed from the start of Period 1 throughout each of the periods.

BY MR. REHWINKEL:

Q So I asked you if, after the failure, you went to Mitsubishi and asked for them to help you --

A Right.

Q -- increase the output in the unit.

A So it's just not so simple as that. It's a very collaborative back-and-forth process, but because we then had to -- we followed this lower, more conservative guidance on the IP exhaust pressure, we were not satisfied that we were getting as much out of the equipment as we could, so that's when we did ask Mitsubishi.

So we don't want to have this limit. We weren't supposed to have this limit. We want to get as much out of the generator as we can. Is there something

that can be done?

They studied it and came back with us -- to us and said, yes, we can redesign the L0 blades and put a different design of blade in both L0 rows, and you will be able to achieve, we estimate, 450 megawatts.

Q Well, are you familiar with the quote that they gave you for an engineering study for additional optimization and reliability for $232,025?

A Could I see that?

Q Yeah. It's on -- it's in Exhibit 102 at Bates 145. It's the late filed exhibit for 145.

A I have 102. Could you say the Bates number again, please?

Q Yeah. It's kind of two-thirds of the way or more back, it's at 145, and it's a real tiny print up in the upper right above the slide.

A I am almost there. Okay, I see that.

Q Do you know what this was for?

A I don't recall what this was for.

Q Okay. If you roll back a few pages to 135.

A Okay, I am there.

Q And this is a part of, I guess, a slide presentation at a joint meeting between Mitsubishi and Duke?

A I am looking back at the beginning to see if I can get an idea.

Q On 122, it talks about August 21st, 2012, discussion.

A Okay. It does appear to be a meeting where we discussed the turbine.

Q Okay. Just back on 135, a discussion -- further discussion to support their own investigation and possible means of increasing unit output.

And then it looks like they have a response. It says: We will continue technical support for you. As of now, it is difficult for us to propose a concrete method to increase the unit output. An engineering study is suggested.

And so my question is, is that what 145 is, is them saying here's what it will cost you for us to do an engineering study?

A It does appear to be that, yes.

Q Okay. And did you engage them to do that study?

A I don't recall if we engaged them to do this study, or if that was included in the ultimate -- we did contract with them to supply new blades that could -- that were theoretically going to be able to raise the output to about 450 megawatts.

Q Okay. So that would have been the most likely

output product of this study if you did, in fact, say, yes, go ahead and do that?

A That -- I would say that would be a likely output, yes.

Q Okay. Now, did that study say that Mitsubishi agreed that you could run the unit above 420 without different blades?

A Well, I am not familiar with the study, but -- so if I could have a few minutes to read it, but I think it's really important to remember that at this point in time, Mitsubishi thought that the root cause was too much steam flow in the low pressure turbine, and that they -- there was a way to get from steam flow and correlate it, as you have already said, to megawatts.

So that's been disproven in later cases, later periods of time. So I am not sure what your question is.

THE COURT: I am going to jump in while we are on a pause here.

One thing we didn't have in our order of procedure was a lunch break. I am just wondering what the will of the, you know, the room is as far as taking a break and how long you think we need.

MR. BREW: Yes, I think we should have one.

MS. BROWNLESS: Yes.

THE COURT: We agree on that. How long? Should we try to get back inside of an hour, or is it going to take an hour?

MR. REHWINKEL: I think an hour is reasonable.

THE COURT: Okay. We will -- we'll say, then, we will reconvene at 120:20, and if everybody, by some miracle, is back sooner, we will start sooner.

MR. REHWINKEL: Okay. Sounds good.

THE COURT: We will stand in recess then.

(Lunch recess.)

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 18th day of February, 2020.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #GG015952
EXPIRES JULY 27, 2020

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STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

RE IN: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR,

Petitioner,

vs. CASE NO. 19-6022

**,

Respondent.
_______________________________/

VOLUME 2

PAGES 157 - 290

PROCEEDINGS: Administrative Hearing

BEFORE: Honorable Lawrence P. Stevenson

DATE: February 4, 2020

TIME: Commenced: 8:55 A.M.

LOCATION: Division of Administrative Hearings
1230 Apalachee Parkway
The DeSoto Building,
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

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INDEX TO WITNESSES

*Huh-uh is a negative response
*Uh-huh is a positive response

P R O C E E D I N G S

THE COURT: Mr. Rehwinkel, whenever you are ready, I think we are all set.

MR. REHWINKEL: Okay. Thank you, Your Honor.

BY MR. REHWINKEL:

Q I want to take you back to the drafts that we called -- that's Exhibit 115. If you can go to that. I think we will spend most of the rest of the time on that document.

A I am there.

Q And I want to take you to Document 2, which is at Bates 19.

A Okay. I am there.

Q Now, the file name for this document says P Crimi comments, do you agree with that?

A I do.

Q And also it says above the text on the upper right-hand side, REV 10-15-16 HMC, do you see that in the -- just above the -- well, do you see --

A I do see that, yes.

Q Okay. Would it be a reasonable conclusion that this is a document that was at least originally generated by Harry Carbone --

A Yes, I would agree with that.

Q -- on October 15th?

Okay. And would it be also reasonable to assume, based on the Duke file name, that Paul Crimi made some comments or edits to this document?

A It would. And one correction, I don't know that Mr. Carbone would have created it, but he certainly, by the revision date, it appears that he edited it.

Q Okay. We wouldn't know necessarily when he did it, but it would have been on or after the 15th of October of 2016, is that right?

A I would say on or before.

Q Okay. Now, Mr. Crimi was a consultant to Duke and also a member of the root cause team, is that correct?

A Yes.

Q Okay. And he is a former employee of Duke and Progress, right?

A Yes, that's correct.

Q And at some point, he was also an employee probably of GE?

A He was, yes.

Q Okay. And would it be fair to say he is a subject matter expert with steam turbines?

A He is.

Q Okay. So let's go down to the second

paragraph -- and just so we understand what these documents are, I mean, the night janitor wouldn't be able to go and make changes to these things? These are -- these changes are all by authorized engineers, right?

A That's correct.

Q Okay. So there is a statement here that starts "it is important" -- could you read that full paragraph there with those edits?

A Yes, sir.

"It is important to note that this turbine was originally designed for another project and built by the OEM but not shipped. It was subsequently reapplied to the Bartow project with the limitations and turbine outputs shown on the heat balances and other documentation provided. However, it was much less clear about the exhaust flow limit the output limit implied since this pressure and flow limit is not clearly stated on the documentation given."

Q Okay. Now, is that -- isn't that true?

MR. HERNANDEZ: Objection, Your Honor, compound.

MR. REHWINKEL: I'll ask you this --

THE COURT: Overruled. Yeah, you can break it down, I guess.

BY MR. REHWINKEL:

Q The first sentence is true, is it not?

A Yes, it is true.

Q The second sentence is true, is it not?

A Yes.

Q And the third sentence is true?

A That one is difficult to say a true or false. It was much less clear about the exhaust flow limit the output limit implied -- again, it's a working document of a root cause team. You are just asking me if that statement is true or false, that sentence?

Q Well, I am asking you if you agreed with that, let me ask it that way.

A I would say I generally agree with that.

The operating parameters to operate the steam turbine are really on -- you know, we, like -- for instance, we don't have, as I stated earlier, a low pressure inlet instrument, so exhaust flow limit, there is no way to measure that, so I think that's what this sentence is getting at.

Q Okay. But there is no expression of a lack of clarity about what the heat balances represent by Mr. Crimi here, is there?

A No, that's correct.

Q And if we go to page 27 --

A Okay.
Q -- in the keynote section under Period 1.
A Yes.
Q It says MHPSA was hired to evaluate ST design conditions, parentheses, original design was for Tenaska 3-x-1 heat balance and continue the warranty. Do you see that?
A I do.
Q Okay. And even though it has an A in there, there is no -- that's still Mitsubishi?
A It is. The A, I believe, stands for America.
Q All right. So somebody, when they developed Appendix A, put 450 megawatts as the steam turbine rating in 2016, do you see that, for Period 1?
A I do see that.
Q And that turned out to be an error?
A Are you asking me if that was an error?
Q Yes.
A It appears it was an error.
Q Okay. But if we go back -- let's go back to page 175 now. Let's go -- go out a year in time.
A 175?
Q Yes, sir.
And this Appendix A here, we see in the line -- or the row that's headed "Operating

Restrictions", do you see that caption?

A I do.

Q All right. And for Period 1, it says none, dash, MHPS intent was to follow heat balance diagrams, do you see that?

A I do.

Q Okay. So that's consistent, is it not, with Mitsubishi's contention that the heat balances were limitations that -- for operating the steam turbine, correct?

A Again, calling heat balances limitations I do not believe is accurate. They are predictions based on a certain set of criteria, and so what this is saying is the intent was to follow those predictions.

Q And that's what Mr. Crimi said a year earlier in his statement, right, that the heat balances were limitations in turbine output, back on page 19, right?

A There is a reference to the heat balances in the sentence -- in the paragraph I read.

Q As a limitation, right?

A The limitations in turbine output shown on the heat balances, yes.

Q Okay.

A Now, again, that's with other operating variables, okay. So a limitation is according to whatever the other variables are for that specific heat case, which there are dozens, as we've seen.

Q So let's go to page 195, and this is -- it's got the draft water mark on it. So I am going to refer to this as the final draft, is that fair?

A I am almost there.

Q Okay. Sorry, this is Document 18.

A Yes, that's fair.

Q All right. So Table A is here, and we see -- if you go back to -- what did I have you look at? 175. Why don't you keep your finger on 195.

A Okay.

Q So this document here, we saw that says operating restrictions, right? For -- on 175 for the one, two, three, fourth column -- for the fourth row down.

A Oh, yes, I see where, yes.

Q Okay. And then if we flip back over to 195, it now says MHPS IP exhaust pressure operating limits.

A Yes.

Q And then for Period 1, it now says machine control to HP, IP and condenser design limits; do you see that?

A I do.

Q Okay. Now, isn't what's happened between the

October 11th draft and February 6th draft is that the question has been changed?

A What question?

Q Well, what the operating restrictions are.

A I think it's pretty clear on page 175, it refers to the heat balance diagrams. And on page 195, it refers to the HP, IP and condenser design limits. I am not sure I understand the question.

Q So if I'm looking at Table A on page 195 -- and let's just go back to page five of the exhibit, which is the final --

A Table A of JS-2?

Q Yes, JS-2. It's identical, it appears, to page 195, right?

A Yes.

Q Okay. So now just working off of this one, this heading seems to ask what are the Mitsubishi IP exhaust pressure operating limits. And then the answer given is different than on the October 11th draft. It says machine control to HP, IP and condenser design limits. It doesn't refer to heat balances, right?

A Correct.

Q Okay. And Mitsubishi never said that these were the operating limits, these meaning what's in column one on page five here. They never said these

were the operating limits. They said 420 was the operating limit, right?

A No, that's not correct.

Q For Period 1?

A That is not correct.

Q In all of their documents that they provided that you provided us, they don't ever say that's the operating limit for Period 1, do they?

A 420 is a predicted megawatt output if a whole bunch of variables, dozens of variables are controlled at certain points, 420 was predicted as the generator output at a power factor of .949, or a power factor of .9.

You have to look at each heat case specifically. That is not an operating limit. 420 was the minimum contractual amount that Mitsubishi had to achieve in order to avoid liquidated damages on the project.

Q I mean, that's your opinion, right?

A That's not my -- I believe it to be a fact.

Q Okay.

A I think we've looked at several pages that show it's a fact.

Q Well, in the RCA process, Duke Engineering didn't see it that way, did they, until you got to the

final document?

A I disagree with that. I don't see how you can draw that conclusion.

Q Let's go back and look at Document 3, which is at Bates 23.

A Document -- I am sorry, JS-3?

Q No. No, sir. Document 3 in 115.

A Oh, okay. I am sorry.

Q That's okay.

A Okay.

Q And just so I understand, this is a document that you have agreed you edited, right -- or you had an opportunity to edit?

A Yes, that's correct.

Q Okay. And at the time you edited this document, you had both access to both the heat balances and the contract and the IP, HP and condenser limits, correct?

A I could have had those available, yes.

Q Okay. I mean, none of that was new information. That all existed back in 2006?

A Right.

Q Okay. So if I look at on page 24, if I could get you to turn to that.

A Okay.

Q In the first paragraph, about halfway down, there is a sentence on the far right that starts MHPS, do you see that?

A Yes.

Q So it says: MHPS Engineering indicated that Bartow Unit 4S was an outlier relative to the Mitsubishi 40-inch L0 fleet with several operating hours above the design limit of 15,000 -- I am stumbling over that -- foot pounds per hour squared, parenthesis, the Mitsubishi 40-inch L0 fleet average was closer to 12,000 foot pounds squared per hour, close parenthesis; do you see that?

A I do.

Q Okay. You didn't propose to make a change to that in your edit, did you?

A It does -- no, I did not.

Q Is that because it's factual?

A I don't believe it to be factual. Remember, this is a draft document, and there is a lot of people looking at it, and I wasn't privy to all the conversations that took place over a long period of time with this root cause team, but I have not seen any Mitsubishi documentation that calls it a design limit. I have seen documentation from Mitsubishi that refers to their fleet -- maybe their fleet average or their normal -- their fleet operating experience, but that the 15,000 and 17,000 pounds per hour per square foot was beyond their fleet experience and put them in a zone of uncertainty.

Q You -- okay. The next sentence -- I mean, the next paragraph, it starts, "While Duke Engineering", do you see that?

A Yes.

Q So would you be considered part of Duke Engineering for purposes of the RCA?

A Would I be?

Q Yes. I mean, you are an engineer. This is in your area. You were overseeing the root cause team?

A We can assume that. Technically I am not and never have been part Duke Engineering, but, yes, I can see -- I was overseeing the process.

Q Right. And I accept that. Just to -- for the judge to understand, Duke, big Duke that serves multiple states has a centralized engineering area, which you call Central Engineering, right?

A Correct.

Q And you also have engineers that are in your direct chain of command that report to you, up the chain to you, right?

A That is correct, yes.

Q Okay. Those two groups of engineers and some outside consultant engineers and yourself would have been all part of bigger Duke Engineering, right?

A Yes.

Q Okay. So this sentence says: While Duke Engineering agrees that back-end loading should be considered a significant contributing factor toward root cause, one cannot definitively conclude that it has been the root cause of all five of the documented L0 events.

You didn't propose to change that sentence?

A Correct.

Q Do you believe it to be true?

A Well, I know that there is some issues with that sentence. For example, there were really four L0 events. And then there was a fifth iteration where we replaced blades proactively to try to get a new design that would provide more megawatt output of the generator, just to make that part clear.

Q Okay. Well, that's sort of a detail, isn't it? It's not really that material to what's going on here, is it? It would cover Period 1, and it would cover Period 5, right?

A Right.

Q Okay. And, in fact, just so we can understand, let's go to page one of this document, and I

just want to ask you something that struck me curious about this sentence.

It says: Duke Engineering concluded that there was no correlation between any one of the above listed factors and the five failure periods, is that accurate?

A Could you show me where on page one that --

Q Oh, I am sorry. I apologize. It's in the next to the last paragraph.

A Oh, page one of JS-1?

Q Yes, sir.

A I am sorry. I was on the wrong document.

THE COURT: I was on -- yeah, final report.

THE WITNESS: Could you point to that sentence again, please?

BY MR. REHWINKEL:

Q Okay. Go to the second to the last paragraph.

A Okay.

Q And it says: Duke Engineering concluded that there was no correlation between any one of the above listed factors and the five failure periods.

Is it events or periods that you are looking at here? I mean, just to go to your point about there were only four events, five periods, but --

A Yeah. Well, I think it's both, right? There was four events where we found damage, but there were five operating periods. One of the periods came after an iteration where we didn't have an event that caused us to shut down, or we didn't find something on an inspection that led us to change out blades, but we shut down in order to install a new design of blade, so that began Period 3. But you can't do the root cause on just periods or just events. It's all-encompassing.

Q Okay. So in that context -- well -- so going back to page 24 now that I understand how you are looking at it.

MS. BROWNLESS: Excuse me, of which document? Of JS-2?

MR. REHWINKEL: I'm just working in Exhibit 115.

MS. BROWNLESS: Okay. So you are on 18?

MR. REHWINKEL: So when I say a page, I mean the Bates number.

THE COURT: Bates stamp, right?

MR. REHWINKEL: Yeah. I am not worried about how the document is numbered.

BY MR. REHWINKEL:

Q So you said there was really four events instead of five events. Apart from that, what other problems are there with this sentence?

A Well, I think the key part of the paragraph that you are pointing to is the sentence that starts, as Appendix A illustrates, Periods 2, 4 and 5 saw operating hours in the avoidance zone of one hour, 1.5 hours and zero hours respectively. This indicates that back-end loading was not the cause of any of the reported blade indications failures during those periods of operation.

Q So you are saying that that undermines, or it takes out any agreement that Duke Engineering had that back-end loading should be considered a significant contributing factor toward root cause?

A Again, this is not the root cause document. This is notes, draft notes of a team. So there is no conclusion here.

Q So why would people have put stuff in here it if they didn't believe it to be true?

A I think it's a process, as we've talked about before, working through probable, possible things that could impact the blades that could cause the damage that we saw.

The -- I think what this says is that Duke agrees that back-end loading needs to be looked at, but then when you look at the real-life operating experience in these periods when we ran lower than even Mitsubishi's fleet experience on steam flow loading on blades, we still had damage with the blades. So that clearly shows the lack of design margin.

Q Let me ask you about page seven of Exhibit 115.

Before I ask you the questions here, you agree that no other Mitsubishi L0 40-inch blade steam turbine experienced the kind of blade failures that you had in Bartow; is that correct?

A I am not 100 percent sure that's accurate. It's -- I just don't know.

THE COURT: Did Mitsubishi make that representation during all this?

THE WITNESS: They did.

THE COURT: Okay.

THE WITNESS: Mitsubishi made that representation, yes, Your Honor. In fact, it was very -- more than that. They talked about how the typical problems in their fleet of low pressure turbines with L0 blades was due to erosion, which is not surprising. That's the same problem across the industry with all equipment manufacturers of turbines.

As the steam travels through a turbine and uses its energy, it gets lower and lower pressure and gets closer to the saturation point where it might turn into water. The blades aren't designed to have water impinge upon them. They are designed for steam. The water can cause erosion, which can lead to cracking and failure. That's what Mitsubishi told us was the issue that they had seen.

We did not see this issue here, but there had been some other indications through user groups, not from Mitsubishi, that there, perhaps, were some issues around the Mitsubishi fleet that Mitsubishi did not report to us.

BY MR. REHWINKEL:

Q Now, I asked you in the deposition for any information from users groups, and you said there was none, correct?

A We have information from users groups.

Q I asked you in a late-filed Exhibit No. 11 to provide it, did you?

A Oh, I don't know that we have documents. We have people who have attended user groups, and we have -- so they've had conversations with people at users groups --

Q Okay.

A -- so that's information.

Q So isn't it true that one of those

conversations was you gave a presentation, and somebody came up to you afterwards and said I am interested in what you are talking about?

A That is true.

Q Okay. But that person never said that that utility had any problems with Mitsubishi that were the same as yours?

A He indicated that they had similar issues.

Q Did he give you any information?

A No.

Q Okay. And did you present any of that information in the root cause analysis?

A No.

Q And you had that information before 2018, right?

A I don't know the relative dates of that user group meeting compared to the root cause.

Q If I asked you that in your deposition and you said it was, do we need to go look at it?

A Okay, then --

Q Okay.

A -- I agree.

Q And there was an inci -- there was a situation in Louisiana where someone came up to Mr. Salvarezza and said he was interested, right, in what was going on at

Bartow?

A Yes.

Q But he didn't say that they had L0 blade problems, that they had failures like you had with excessive vibration, right?

A That's correct.

Q Okay. And that was before 2018, correct?

A Yes.

Q And that didn't show up in the RCA or any of the documentation that we were provided other than that Q&A in the depo, right?

A We tried to verify through various means. The fleet operating experience is obviously very important. We rely on our OEMs for that information typically, whether it's GE or Siemens or Mitsubishi. User groups are also important, but we couldn't find any documentation that there were similar failures to what we've experienced at Bartow.

Q Now, would you agree with me that there are 32 Mitsubishi L0 40-inch blade steam turbines out there in the world? I don't know if that includes you or not.

A I think at the time of this document, that was the number that was used, right.

Q So you are one of 32 or you are one of 33?

A I don't know. There is probably more than that now. In fact, I know there are more than that now.

Q But at that time, there was 32 or 33?

A Yes. Yes.

Q And that was, like, 55 or 57 rows of blades among all those units?

A Oh, yes, that's -- it was in the fifties.

Q Okay. And you have provided no evidence that any unit other than Bartow among that fleet had blade failures based on excessive vibration like you experienced?

A That's accurate.

Q Okay. And you also agree, I think we just talked about it in that draft, is that Duke Bartow was an outlier compared to all of the other Mitsubishi L0 40-inch blade steam turbines?

A It was an outlier on steam flow pounds per hour per square foot, right.

Q Wasn't it also an outlier in blade failure experience?

A Yes.

Q Okay. Now, just to be clear in the R -- in the -- if we go back to JS-2, the word outlier has been taken out of the root cause analysis. In other words, it doesn't show up in there with respect to how you compare to Mitsubishi, right?

A How the Bartow plant compares to Mitsubishi?

Q Yes.

A I will take your word for it.

Q Okay. I mean, isn't it also true that in these documents that were -- that preceded the final draft, there was a reference to the Mitsubishi experience and that got converted to industry experience. So you took out the comparison of Mitsubishi plants with respect to the blade failure experience comparison, right?

MR. HERNANDEZ: Objection, Your Honor. We are talking about a lot of documents. He is referencing specific language in those documents. If the witness could see the documents to answer the question specifically.

THE COURT: Sure.

MR. REHWINKEL: Sure. I mean, we can go through it.

BY MR. REHWINKEL:

Q Let's go to page 125. Just pick one. And this is Document 13 under the tabs.

A Okay. I am there.

Q And if you go back to 123, it looks like it was a October 12th document.

A Okay.

Q And back on page 125, and the one, two, third full paragraph there, halfway down it starts on the right-hand side, the number of blade failures and problems with ST L0 blade performance is not typical, i.e., these issues are outliers among the Duke CC fleet as well as the Mitsubishi 40-inch L0 fleet.

Did I read that right?

A Yes.

Q And that's true, isn't it?

A As far as I know, that is true.

Q Okay. Now, is it fair to say -- and if you go back to JS-2, which is Document 1, that sentence does not reappear, does it -- or let me withdraw that and say that sentence does not appear?

A It doesn't, but I don't -- again, we talked about this before. All these documents you are going through are drafts of a working team. There is notes. They are not a final root cause, and I wouldn't expect the final root cause to be identical to any of these documents.

Q Well, let's look at page two of Exhibit 15, it's also JS-2.

MR. BERNIER: So two of JS-2?

MR. REHWINKEL: Yes.

MR. BERNIER: Thank you.

BY MR. REHWINKEL:

Q In the second full paragraph it starts "based on", do you see that?

A I do.

Q This is your ultimate conclusion, right?

A It is. We discussed that before.

Q And this doesn't mention a comparison to elsewhere in the industry, but elsewhere in the industry referenced there is really Mitsubishi, right?

A No, that's not accurate. If you look at the footnote at the end of that paragraph, that refers down to the -- I will read it to you.

The most commonly reported issue with the 40-inch L0 blade design elsewhere is water erosion, which both Duke and MHP also agree is not a contributing factor to the Bartow failures. So I really was referencing the industry in general.

Q Okay. So -- but the outlier language and the comparison to Mitsubishi and those other 32 plants, experience is not contained in the final report that the Public Service Commission gets to see, right?

A It's not in the root cause. And by agreeing to what you just said, I am agreeing that these are various drafts of root cause documents, which I don't agree with that.

Q Wait, now, you don't agree that Bartow and Period 1 was an outlier compared to the rest of the Mitsubishi L0 40-inch steam turbine fleet?

A An outlier from the standpoint of steam flow, and an outlier from the blade, the snubber and Z-lock damage we talked about, yes, I agree that it was an outlier.

Q Okay. All right. So now I started this line of questioning by asking you to go to page seven, and look at footnote six.

MR. BERNIER: Seven of which? I am sorry.

MR. REHWINKEL: Of 115.

MR. BERNIER: Got you.

MR. REHWINKEL: It's the same as --

THE WITNESS: Okay. I am there.

BY MR. REHWINKEL:

Q You are there. And you see footnote six down there?

A I do.

Q Would you mind reading that aloud? And I am going to ask you about the last sentence.

A Okay. Even though the L0 blades are no longer in the ST and the pressure plate has been installed, MHPS Engineering does not have enough technical data to support releasing Duke to operate the machine beyond the current IP turbine exhaust pressure operating limits because of potential impacts to upstream blading. That is the L1 blade sets. This suggests that MHPS is unsure what effect, if any, is created by its avoidance zone, and more importantly, points to a design flaw that affect more than the L0 blades.

Q Now, this statement about a design flaw, is there an analysis that was conducted to determine that there was a design flaw in the L -- in the Mitsubishi steam turbine that you bought?

A I think this statement is pointing to the fact that Mitsubishi couldn't relieve the operating constraints that were in place. Even after we took the L0 blades out and put a pressure plate in, Mitsubishi still said you need to operate at a more conservative -- or the more conservative operating parameter led Duke to believe that there is more concern on Mitsubishi's standpoint that perhaps it's not just an L0 issue, perhaps it's an issue elsewhere in the low pressure turbine, and that perhaps they are questioning their own design.

Q Well, what is elsewhere in your opinion? The upstream blades? The nozzles? Anything?

A Well, technically, thousands of blades are the same thing, but, yes, the -- so the -- well, let me show this picture.

So upstream would be -- so remember the steam goes in the middle of the turbine and then goes this way and this way. So here's the L0 blade, the largest blades. Upstream of that would be this row of blades and this row of blades.

So there was concern that perhaps we need to continue operating at that lower pressure limit because maybe there would be damage to other blades that Mitsubishi appeared to be questioning their own design, and that perhaps those rows of blades might become damaged.

Q But beyond this footnote, there is no analysis where you determine that there was something wrong with the turbine, is there?

A There is not. But I can tell you we obviously very concerned every time we opened up this machine, and we had multiple opportunities to do very detailed inspections on the steam turbine, many more so times than is the norm.

At the end of Period 1, we did an inspection. At the end of Period 2 -- at the end of every single period, we did a very detailed inspection of those blades, so we had to gather that information.

Q How many 4-x-1 combined cycle units did Duke

have experience with before you commissioned Bartow?

A This is Duke's only 4-x-1.

Q Okay. And how many 4-x-1 -- so would it be fair to say that you did not have robust operating experience with a 4-x-1 combined cycle unit?

A Yes.

Q Are you familiar with Exhibit 106 -- it's the August 13, 2018 -- called the settlement.

MR. BERNIER: 106?

MR. REHWINKEL: Yeah, 106.

THE WITNESS: Yes, I am.

BY MR. REHWINKEL:

Q Okay. Now, is it --

MR. BERNIER: Give us one second, Charles. I am trying to find it.

MR. REHWINKEL: Oh, I am sorry.

MR. BERNIER: Okay.

BY MR. REHWINKEL:

Q So if we go to the back, page 11, we see Tony Salvarezza signed this thing on October 13, 2018?

A Yes, I do.

Q And you would agree that Duke was having discussions and trying to either work -- well, trying to work out a resolution of these matters with Mitsubishi at sometime not long after the RCA was completed?

MR. BERNIER: Judge, I am going to have to object to this. I am not sure how any resolution Duke was trying to work out with Mitsubishi has anything to do with how the unit was operated leading up to 2017, or after 2017 when the pressure plates were put in. And I think those are the two issues that we are here to talk about today. And I am not sure how a settlement agreement is relevant.

THE COURT: Well, you are going to show us it's relevant?

MR. REHWINKEL: Yes.

THE COURT: Okay.

BY MR. REHWINKEL:

Q And my question is: You signed -- you provided -- you finalized an RCA and you filed it with the Public Service Commission on March 1st, right?

A I don't know that that was the date of filing, but yes.

Q Sometime in March?

A It was done in February -- it requires it's finalized in February, so that makes sense.

Q And you filed testimony in March of 2018?

A Yes. Yes. Yes. March 1st, you are right. Thank you.

Q Okay. And in this document, it says there was

a design flaw in the turbine, right?
A Could you point to where you are looking at?
Q I am sorry. When I say this document, I am pointing to your root cause analysis at page seven.
A Page seven of the root cause analysis?
Q Yeah, footnote six that we were just talking about.
A So, yes, it says it suggests that Mitsubishi is unsure, and that there may be a design issue.
Q And it says, more importantly, points to a design flaw that may affect more than the L0 blades, right?
A Yeah.
Q Okay. So my question to you is, you just said there was a design flaw in February. In August you signed an agreement where you gave up all your rights to sue under the contract that you bought the unit for, isn't that right?
MR. BERNIER: I'm going to go back to objecting, Your Honor. I just don't see how that's relevant to how we operated the unit, how Duke operated the unit in 2017, the decision whether or not to settle any potential contract claim. I just don't see the relevance to the two issues we've got identified here today.

MR. REHWINKEL: My response to that, Your Honor, is that the root cause analysis we established early on today that this is their principle evidence to meet their burden of proof. This root cause analysis purports to be what happened, and they are asking the Public Service Commission to rely on it to absolve them of any liability to the customers for replacement power.

One the problems that we've raised is that the way they ran the unit in the first period has caused problems in later periods. They have -- and part of our case is that their explanations about the blade are inconsistent with the experience other units have had.

Now, in the root cause analysis, they are saying that there may be a design fault with the turbine itself, not the blades, which is what their whole case is about, but the turbine itself; and they are asking the Commission to rely on that while they are settling with Mitsubishi to give up their right to sue for a design flaw.

It doesn't -- so we are offering this as impeachment to the conclusions in the RCA because the RCA is submitting that there is a design flaw while, at the same time, they are giving up their right to sue. That's an inconsistency that we would like you to consider in your fact-finding.

THE COURT: I am going to allow it, but -- I mean, it's without prejudice. I mean, you can continue to argue that it's not relevant. I am not sure that you are totally tying it up, but I am going to at least let them present it.

MR. BERNIER: Understood.

BY MR. REHWINKEL:

Q Okay. So my question to you was is that what happened?

A Well, I think there is more to this agreement that you are not talking about that's pretty important, and you need to also think about the whole timeline of events and what the warranty provisions were in the contract, which I don't know specifically, but typically, there is about a three-year warranty period. It's typically one year for some pieces. It may be two years, three years if you are lucky, all right. So that's from '09 when we first started operating. This agreement was in 2018, six years later. So I don't know is that we had any warranty claim left on the original blades, and I think that's what you are inferring.

Q Well, if you are saying there is a design defect?

A Even for a design defect.
Q Okay. And we don't know -- and I am not asking you to resolve that question because I know you are not an attorney, right. But the -- my original question that started this line is what analysis did you do to demonstrate that there was a design flaw in the turbine? And I don't think there was one, was there?
A I think we are -- well, what we are saying is that there was inadequate design margin at the very least.
Q That was for the blades, right?
A Well, you are -- I think you are misinterpreting something. So look back at the point that -- the wording that you are pointing to is on page seven of JS-1 and JS-2, correct?
Q Page seven, footnote six.
A Right. So the last sentence, this suggests that MHPS is unsure what effect, if any, is created by its avoidance zone, and more importantly points to a design flaw that may affect more than the L0 blades. So what do you mean when you say the turbine?
Q Well, the part of the turbine that's not the L0 blades, everything else that you showed the judge on the picture.
A So -- which would be the L1 blades, the other

sets of blades, which we know from very detailed examination didn't have any damage. We looked way more times than we should have, but we gained a lot of information doing those inspections.

Q And is there -- did you present any evidence in this RCA concurrent with this assertion here in this footnote that any other Mitsubishi L0 40-inch steam turbine units were having the same kind of problems, or had a design defect or flaw in them?

A That wasn't the question of the root cause. The question of the root cause is why did these snubbers and these Z-locks fail?

And so, yes, you take into consideration what is that fleet experience? And the root cause shows, or says we reviewed, the team knew that the fleet experience at the Bartow plant was an outlier compared to the Mitsubishi fleet from a damage standpoint. But when you go back and look at what caused the Bartow failure, that's what the root cause is about. It's not about -- we didn't do a root cause on Mitsubishi's issues. We did a root cause on Duke Energy's issues.

Q But if there was a design flaw, it wouldn't have been just -- not a manufacturing flaw, you are saying it's a design flaw. That would have applied to the other 32 units, right?

MR. HERNANDEZ: Objection, Your Honor, foundation.

THE COURT: Overruled. I mean, I think it's understandable.

THE WITNESS: Potentially it could be applicable to the other units. And you have to look at the design conditions, the operating parameters of each of those 30-some units, or 50-some rows of blades that we talked about. And if any of those other 50 blades were operated the same way as Bartow within the guidelines established by the OEM, I would be pretty worried if I owned one of those other sets of blades.

BY MR. REHWINKEL:

Q Well, you agreed you are an outlier, and they didn't have any of the same kind of problems, right?

A Correct.

Q So why wouldn't -- isn't that just as correlative that there is not a design flaw in there because they are not having any problems and only you are?

A Not necessarily. That's a factor that you have to take into account, but the operating parameters at Bartow -- we just talked about how Bartow is a 4-on-1 combined cycle. We talked about how it's an outlier compared to the Mitsubishi fleet. It's about 15 -- the calculation is about 15,000 pounds per hour per square foot of impact on the last stage blades, which is an outlier to the Mitsubishi fleet, but we operated within the design parameters given by Mitsubishi.

They didn't say, don't operate beyond 15,000 or 17,000. There is no way to measure that. They said, don't operate beyond this operating pressure. Don't operate besides this -- beyond this operating temperature, which we did.

Q Would you agree with me that Exhibit 106 covers claims that dated back to Period 1?

A Yes.

Q Okay. And what -- basically what you did here, I -- and tell me if I am oversimplifying it, is you had -- they had a claim against you for, like, $10.2 million and you had a claim against them for $6 million, and you settled it where you gave them $3 million and they gave you a $2 million credit on the next set of blades, is that --

A That's a fair summary.

Q Okay. So I just want to ask you about --

A I am sorry, with one exception. I am sorry.

Q Sure.

A The credit could have been used in many different ways. Not necessarily at Bartow.

Q Right. It specifically mentioned you could use it on the blades, but you could use it elsewhere under other conditions, right?

A Correct.

Q Okay. And it can be read in here, right?

A Yes.

Q So let's just go to page one, and I just want you to read for the record the last two whereas clauses aloud, please.

A Okay. Whereas, after the steam turbine was commissioned in June 2009, MHPS designed enhanced L0 blades that would endeavor to allow Bartow station to increase its output from 420 megawatts to 450 megawatts, and whereas, the parties entered into purchase order 718383 on February 10th, 2014, whereby MHPS was to design and install such enhanced design L0 blades at a $6 million cost to DEF, which amount DEF has paid.

Q Okay. So this is a document that Mr. Salvarezza signed on behalf of the company, right?

A Yes.

Q So he agreed to what is stated in these two whereas clauses, correct?

A Yes.

Q And doesn't that say that, reading these two

together, that the output of the steam turbine was 420 megawatts and you wanted to increase it to 450, right?

A Generally that's correct.

Q And that specifically is in Period 1 that it's 420, right?

A Yes.

MR. REHWINKEL: Your Honor, I believe if we take a short break here, I can substantially shorten the day at least from what I am contributing to it.

THE COURT: How long do you need?

MR. REHWINKEL: Just five minutes.

THE COURT: Five minutes. Sure, we will take five.

(Brief recess.)

THE COURT: Back on.

Whenever you are ready, Mr. Rehwinkel.

MR. REHWINKEL: Thank you for that, Your Honor. And I think it did help a great deal. Thank you.

THE COURT: Yep.

BY MR. REHWINKEL:

Q Let's go to -- we are still on Exhibit 115, and go to page two.

A Okay.

Q And if you wouldn't mind reading the second paragraph above where it says historical overview, where it says for Bartow, just that sentence.

A Starting with the words "for Bartow"?

Q Yes, sir.

A For Bartow, the long-term solution is to replace the L0 blades with blades of a different design and/or to retrofit the LP steam path and/or continue operation with pressure plate.

Q All right. Would you mind explaining, so that -- to the judge what is referred to there as the LP steam path?

A Yes, sir.

May I stand up, Your Honor?

THE COURT: Sure.

THE WITNESS: So the three options are essentially replace the L0 row again, the two rows with another design of blades, or when we say the whole low pressure steam path, it would basically be lifting this section of the overall turbine generator out and putting a different low pressure turbine in.

So that would entail all rows of blades, all rows of fixed diaphragms in between the blades, the casing, everything associated with the low pressure turbine.

BY MR. REHWINKEL:

Q Thank you.

And it says and/or there, is that correct?

A It does.

Q Now, I am not trying to -- just for factual purposes, in October, November of this year, you actually put in the solution that you chose, which was we call the Period 7 blades?

A We are on Period 7. Yeah, we put in another iteration of blades redesigned that had very significant testing done at a facility in Japan that we witnessed. Those blades were installed November, December timeframe. I can't remember the date we started up, but it was in, I think, early December. So we are operating with those -- that generation of blades right now.

Q Okay. So is it fair to say that -- well, so now Mitsubishi has installed the fourth set of blades on this -- on that low pressure turbine, is that fair, or a different set?

A Well, we installed one end at the start of Period 2, then both ends at the start of Period 3, both ends at the start of Period 4, both ends at the start of Period 5. The start of period six had pressure plates.

So to your point, this is really the start of Period 7 with new blades, but I think it's more than four.

Q So it's five sets?

A Yes.

Q Now, this is just a hypothetical, because I am not suggesting that it's not going to work. But if there is a problem with this set of blades, will you replace the steam path for certain?

MR. BERNIER: I'm going to object. Again, we are going back to the two issues of operation, and now we are dealing with a hypothetical about what could happen in the future.

THE COURT: That's -- well, I will overrule it again. I mean, Mr. Swartz, if you have any notion, you can answer.

THE WITNESS: Well, let me start by saying one big difference in this iteration is we've installed a permanently-mounted blade vibration monitoring system along with the new sets of L0 blades. So as we increase load, we can take data.

It's very much like the temporary system that was used at the beginning of Period 3, where we came up with the avoidance zones. This is a permanently mounted system, much more robust, so it's made so it's not going to come apart and potentially cause what we would call domestic object damage inside the turbine.

That gives us much greater confidence that we will find an issue prior to any type of vibration that would lead to component failure. So I think that's a really significant difference with what we did with this iteration of blades.

You know, the hypothetical, what would we do if this set of blades failed? Really, we would have to -- like, how would they fail? I mean -- and I am not trying to be funny, but was it an erosion issue? Was it high cycle fatigue? Was it a snubber? Was it a shroud?

I think it depends on the type of failure. If it's an erosion issue, for instance, there are ways to deal with that. So it really depends.

I think where you are going, though, is, you know, our appetite -- my personal appetite for putting in more sets of blades is very low, you know, that's why we put a pressure plate in at the start of Period 6. No more trying. We've got to figure something else out, and our customers can't stand that.

And I think that was a really good decision, a very sound decision, because once we put that pressure plate in in the spring of 2017, we finally had two-and-a-half years of nothing happening. Yes, we ran about 40 megawatts lower from the total output. Instead of a 1,200-ish megawatt site, it was 40 megawatts lower than that. But we didn't have any issues where we had to shut down for the low pressure turbine, and I think that was really good for customers.

It was the right decision while we were figuring out what we could do for the next iteration, which I do believe will be the long-term solution, but Period 7 is going to go on for a long time.

BY MR. REHWINKEL:

Q Just on your blade vibration monitor point, it is true, as is stated in the next sentence, that even had you replaced the steam path, you still would have insisted on a blade vibration monitor as a part of anything that was done, right?

A That was Duke Energy's position. We wanted to make sure that that was part of the solution. Not all the -- not all vendors agreed to that.

Q All right.

A So it actually disqualified some from the -- from that project.

Q And GE was a close second to the solution that you put in in the fall of '19, right?

A They were.

Q Okay. And the fact that it says and/or means that you still haven't completely given up on maybe replacing the steam path, right?

A I think the and/or is really just trying to show that there were three options, that they're not mutually exclusive, right? Let me get back to the sentence and read it again.

Right. So it might require new designed L0 blades and a new steam path. That's what the root cause is showing. But at the point of this root cause, we didn't know what the long-term solution was. So we're just leaving all options open while the team studied what the ultimate long-term solution would be, which we then decided, you know, long after, months after this.

Q Okay. When you did your industry experience research, you didn't find any instance of an L 40 -- an L0 40-inch steam turbine in the Mitsubishi fleet having to replace even one set of blades in 11 -- after only 11 years of operation, did you?

A I am not sure. I actually suspect that there were issues, but likely caused by erosion.

Q Okay. I should have added based on a

vibration-induced damage?

A Right. No snubber or shroud issues like we've experienced at Bartow.

Q Okay. So with that clarification, your research didn't reveal --

A Correct.

Q And you did not, likewise, turn up any industry experience that showed that a L0 40-inch Mitsubishi steam turbine operator had to replace a steam path?

A Correct, we did not find anything of that.

Q Okay. All right. I have just have a couple of sort of clarification questions to ask you on -- I am still on 115, and I want to take you back to page 17 of 18, which is Exhibit 17 --

A Okay.

Q -- exhibit page 17.

Can you tell me why Citrus L0 on the far right-hand side is the header for that column?

A I may be on the wrong page.

Q I apologize. It's the one -- it's the Appendix A in your JS-2. It's page 17, and it says Appendix A.

A I am sorry, I was on page seven.

Q Sorry.

A All right. I am there.

Q So my question to you is: Can you tell me why Citrus L0 is the header for the far-right column?

A I don't know specifically, but what I do know is that Duke had -- Duke Energy had some concerns over the Citrus L0 blades.

Citrus combined cycle is our newest plant. It's two 2-on-1 combined cycles on one site, and it does have Mitsubishi equipment, Mitsubishi combustion turbines and Mitsubishi steam turbines. So there is two steam turbines, and it does have 40-inch steel blades, so there is a similarity there.

The design at Citrus is such that the calculated steam flow -- we've been talking about this pounds per hour per square foot number. It's less than 11,000, or around 11,000 at Citrus. So because of that, Mitsubishi doesn't not think that there is any issues, but I believe they are similar to Type 5 blades, or they are Type 5 -- Mitsubishi Type 5 blades, which don't mistake that with period, right. So they are different style of blades than any of the iterations at Bartow, but they are similar in that they are 40-inch steal L0 blades, if that makes sense.

Q Okay. I just wanted to understand whether this was supposed to be an identical comparison of what

you are putting on as a type -- as a Period 5 blade, and that's --

A I know we obviously had concern with this Citrus project because of what were finding out, or what we found out here. So we are just showing for comparison purposes what is installed at Citrus.

Q Okay. I understand that.

And can you tell me, do you know at what point in any of the periods any of the damage to your L0 blades occur at Bartow?

A We do know. If we could look -- if we look at that same exhibit and go to -- just because it's going to help me remember some things. If we go to page five. It's Table A.

During Period 4, we were able to pinpoint when some of the damage occurred. We had -- if you look at the keynotes from period row and go over to that Period 4 column, it said -- it shows the two separate step changes that were actually reductions, decreases in vibration, led Duke Engineering recommendation to remove the steam turbine from service for inspection.

So there was discussion with Mitsubishi after we noticed these reductions in vibration. It's interesting, Mitsubishi believed it to be bearing settling in, just some normal course of action after an outage on a steam turbine, which we had just had an outage at the start of Period 4. Our Duke Engineering wasn't convinced.

It's -- an unexplained change in vibration, you know, typically -- well, you monitor vibration for increases. If there is an increase in vibration, you need to understand why, and if you can't figure it out, if it gets beyond a certain point, you typically stop operation and go conduct inspections, because that can lead to damage very significant issues in multiple components.

In this case, there were slight changes and there were reductions, but after inspection, we -- when what we found, we found, looking at row broken snubbers in the row that's titled "Broken Z-locks", we found one broken snubber on the generator end of the machine, one broken Z-lock on the turbine end of the machine, and two broken Z-locks on the generator end of the machine, and so that's one, two -- that's four pieces of metal. Small pieces of metal. Remember, we are talking about the snubbers and the Z-lock. But two of those instances were almost certainly the times we saw the slight reductions in vibration.

So the fact that we shut down to do an inspection and take a look was the right thing to do, the prudent thing to do. Before we could operate any more, we had to replace blades yet again.

Q So is that the only --

A That's not the only time. I am sorry. Back to your question.

In Period 5, if you look at the same row, keynotes from period, it doesn't show the date, but we do know same -- similar type of thing. It wasn't vibration in this case, but we had two things happen simultaneously.

We had a decrease in pressure of vacuum. We are losing vacuum in the condenser. And we also, all of a sudden, have indications of sodium in the condenser.

The cooling water that flows through the condenser is saltwater. It's from Tampa Bay. So sodium is much easier to monitor than chloride level, so we monitor for sodium. Any indication of sodium above very, very minute traces is a large alarming. If you get sodium, or especially chlorides into your pure water that you are going to just turn back into steam and reuse it in the process again, that causes all kinds of issues in the system, and potentially turbine issues in the long-term.

So we got an alarm that we had high sodium. We have an alarm that there is reduction in vacuum, so we shut down the turbine immediately. So we know when that failure occurred as well. So Period 4 and 5, we do know when those happened.

Period 1, we don't know when that happened. Period 3, we don't know when that happened.

Q Okay. And for Period 1, 2, 3, 4 and 5, can you tell me what pressures were on the blades at the time damage occurred?

A By pressures on the blades, you mean this mass flow rate that we've been discussing?

Q Yes.

A I don't know that number. Again, it's a calculated number. What I can tell you is that we were operating below whatever the LP turbine or IP exhaust pressure limitation was at the time.

Q Okay. Mr. Swartz, those are all the questions I have for you today?

MR. REHWINKEL: Thank you, Your Honor.

THE COURT: Who's next?

EXAMINATION

BY MR. MOYLE:

Q Good afternoon. I am Jon Moyle, I am representing the Florida Industrial Power Users Group.

You have been in the electric world a long time, have you not?

A Yes, sir, I have.
Q Okay. Are you familiar with the U.S. Energy Information Administration?
A Not really. No, sir.
Q EIA, you have never --
A It's somewhat familiar, but I wouldn't say I am -- the acronym is, rather, but I am not familiar with what it does.
MR. MOYLE: I have a document if I can just show him?
THE COURT: Sure.
THE WITNESS: Thank you.
BY MR. MOYLE:
Q Sir, I have handed you a document from U.S. Energy Information Administration. It's a glossary of terms under the letter G, right?
A Yes.
Q Okay. I might have handed you my copy that had a little star on it.
A Oh, it has the answer on it.
Q The generator nameplate capacity, which is on page three of six, do you see that?
A Generator nameplate capacity?
Q Right.
A Yes, sir.

Q Would you mind just reading that into the record?

A Generator nameplate capacity installed. The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer -- designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in megawatts and is usually indicated on a nameplate physically attached to the generator.

Q Okay. Are you comfortable with that definition for generator nameplate capacity?

A I am.

Q Okay. And a couple of follow-ups on that.

Does the unit that we are talking about here have a, you know, have a nameplate on it?

A I don't know.

Q If you were to show me around, you could you say, Mr. Moyle, let me show you our nameplate, and it would be right there, and I would see 420?

A I wish I could tell you. I don't know if it has a physical nameplate or not.

Q So you just don't know one way or the other on that?

A I don't. But what I can tell you is in the contract -- we looked a little bit earlier today at the generator capability curves, and that does include the nameplate ratings of the generator.

Q Right. And there is nameplate -- I mean, we have it throughout these documents, right? You looked a it, and that chart you were looking at it says 420, right, in your root cause analysis?

A Right.

Q And I just want to get your understanding on the record with respect to nameplate and what it means.

Also, with respect to when Duke or others announce a project, don't they typically announce it by using the megawatts that are expected from the nameplate?

A Yes, I would agree with that.

Again, we typically -- that's our product. That's what people are familiar with, and that would make sense to make announcements in that manner.

Q Okay. I am wanting to ask you some questions about the root cause analysis.

If I understand -- I mean, the history of this generator is, is that it's referred to in some of your documents as it got picked up on the gray market, right? You have to say yes or no.

A Yes, I am sorry, yes.

Q The court reporter needs to put nodding head yes.

A Sorry.

Q Anyway, that's all right.

And so the gray market is, you know, kind of an interesting term. What does that mean, the gray market for generators?

A So the gray market would mean it wasn't bought -- or a piece of equipment isn't bought from the original equipment manufacturer. In this case, the steam turbine that was installed at the Bartow project was purchased -- it was originally manufactured for a different company for a different project, and so -- and that project fell through. I don't know why it didn't come to fruition. And so instead of going to the original equipment manufacturer and buying something directly from them, it was this one that was already there that was really owned by a company called Tenaska, and we purchased that one. So that would be the gray market.

Q Yeah. Would it be somewhat analogous to if I was going to buy a Ford F150 truck, I can buy it from the dealership and nobody had owned it before, or I could buy it from somebody who bought it from a dealership and then drove it home and then said, you

know, I don't really like it and left it in his garage for a few years and I bought it from him in his garage after a few years; is that fair?

A I don't think it's exactly fair.

In this case, the turbine was never delivered to Tenaska. It was kept in storage at Mitsubishi, so it was subject to the same -- whenever Mitsubishi or any turbine manufacturer makes a product, they are manufacturing it and they are storing it under a certain set of conditions. So this one was stored in those same sets of conditions as a regular new turbine, never left Mitsubishi, but stayed -- or never -- yeah, never left Mitsubishi, so it -- yeah, it didn't go to that other person's garage in your --

Q Yeah. And so you -- as we sit here today, you know for sure it didn't get in a warehouse somewhere else. It stayed on Mitsubishi grounds and stayed in their warehouse, or you are not sure of that?

A No. It's my understanding Mitsubishi had possession, and we've actually looked at -- well, the project team involved in the project looked at all kinds of documentation of the storage conditions from manufacture to the date of purchase and to inspections as well.

Q How long from date of manufacture to date of

purchase for you all, how long did it stay in the warehouse?

A I am sorry, I don't know that number.

Q It was more than a year, was it not?

A It was more than a year, yes.

Q Do you know if it was more than five years?

A I don't think it was more than five. It may have been around four, if I remember correctly.

Q Yeah. Are -- I have a boat. And people tell me on my boat that the best thing you can do for it is use it, run the engine, that you need to run the engine to make it operate okay. Have you ever heard anything like that being an engineer, it helps to run things?

A I have heard similar things like that, but I would also tell you that that engine then is going to need more frequent maintenance intervals because you put on run hours.

Q Yeah. Yeah. The engine -- the turbine you bought, it was not run while it was in the warehouse, correct?

A Correct.

Q Okay. And if things are not run, there are issues that can arise from an engineering standpoint, correct?

A Not necessarily. Again, you have to think about how this turbine is stored, and it was actually stored under inert gas pressure in casings with the pressure monitored so the regular atmosphere that we are breathing now never even got to the turbine, so that prevented corrosion, for example.

Q Was the plant near the sea? I mean, Japan is surrounded by a lot of water, is it not?

A I don't know.

Q You don't know where it was?

A I don't know where the plant was.

Q There have been a lot of questions about root cause analysis, or RCA, and let me just make sure I got this right. You all, Duke, did a root cause analysis, correct?

A Correct.

Q And that was comprised of seven people who are all Duke employees, correct?

A I think that's what this says. One of them was actually a consultant, as Mr. Rehwinkel pointed out, a former Duke employee, that at the time of the root cause was actually a consultant back for the company.

Q Okay. So you had six Duke employees and some person who was a Duke employee for a number of years that recently left and came back in?

A Yes, sir.

Q Okay. And you were not on that seven-member team?

A That's correct.

Q Okay. So some of the questions that Mr. Rehwinkel asked you, you were struggling a little bit and surmising, and there were a couple of objections from your lawyer about I don't want you to have to guess. I assume that's because you weren't involved in drafting the report, correct?

A That's correct.

Q All right. Mitsubishi, they also did a root cause analysis, did they not?

A They did. In fact, I think they've done multiple root causes.

Q Right. And their first take at it, their first take at it was essentially too much steam is being put through the process, correct?

A Too much steam to the low pressure turbine, yes.

Q Right. And your -- your being Duke -- root cause analysis, you spent a lot of time with Mr. Rehwinkel on it. I am going to try to characterize it at a high level and see if I can get you to agree that you are comfortable with this, but that there were identified a number of possible causes for the problems

that happened to the turbines, correct?
A Correct.
Q And you all couldn't really come to 100 percent conclusion, decisive conclusion as to what caused the problem, but you said, here are what we think are our best ideas as to what caused the problem, correct?
A That's correct. And we are able to conclude based on in-depth analysis that that lack of blade design margin was the root cause.
Q Right. And it struck me a little bit as, like, well, you couldn't figure out exactly what it was, so it was, like, well, it wasn't designed right. But I am -- I was a little curious about how you all followed up on that, and you -- I think Mr. Rehwinkel asked you what was the design flaw. I think you said, well, it wasn't designed within the right margins, is that right?
A I don't know if that's what I said, but as far as follow-up, it's difficult at that point because essentially Duke Energy is saying, Mitsubishi, we believe you have an inadequate lack of design margin in your blades. The OEM does not want to admit to that. They did admit in their later presentation in the fall of 2017 that the blade flutter was caused by -- or that the failures were caused by blade flutter in all of the

periods.
Q Yeah. And blade flutter, that's like vibration, right?
A It is. Same thing.
Q And you can get vibrations caused by a whole bunch of things, correct?
A Yes.
Q Yeah. Including putting too much steam through. If you are putting too much steam and it's not designed for that, that can cause vibration or flutter, correct?
A That's correct.
Q All right. And it could be some other things?
A Yes.
Q Okay. But in terms of Duke looking at it, you all never came to a conclusion with respect to -- I wrote it down -- the margin. You said they didn't design it and they didn't have enough design margin, I think; is that right?
A Right.
Q And design margin, what is design margin? I assume it's like a level of tolerance. They say, oh, well we can, you know, do this or do that. Is that right?
A It is. For many pieces of equipment, they may

be designed for a certain level, but there is an engineering design margin or extra capacity that's built in, or design factor that if someone were to go above or if the limit is low or below, then there won't be a failure or an issue with that particular component.

Q Yeah. And that wouldn't make a lot of sense, would it, if somebody was operating an expensive piece of equipment that you had, you know, zero tolerance, right?

A It would not make sense, right.

Q And wouldn't it make sense for a manufacturer also to make sure that the equipment is not torn up to say, here, y'all should operate it, you know, at this level, you know, give you some good parameters in which to operate the piece of equipment?

A Yes.

Q All right. And given the definition we just read, you know, the federal government with respect to their definition of generator nameplate capacity, they call it the maximum out -- maximum rated output of a generator is what that 420 would be, right?

A That's what that said, yes.

Q Okay. And when you were doing your investigation, or your critical -- your root cause analysis and you said, well, we don't think it was

designed within the right amount of tolerances, can you tell me anything about that? Like, did you say, oh, you only gave it a five-percent tolerance, or a 20-percent tolerance? I mean, do you have anything substantively more than a conclusionary statement that it wasn't designed within a range of tolerance?

A Well, I think --

Q If you give the answer yes, no, and then explain it, that would be great.

A Well, it's difficult to say yes or no because it's a complicated issue, and I think it's most important to go back and look at what happened across all the periods. So you keep talking about steam flow and operating above a certain amount of steam flow.

Starting with Period 2, the operating pressures that we ran the steam turbine at were reduced, and then throughout Period 2, 3, 4 and 5. In fact, in Period 5, they were very low, but yet the blades still had damage to the snubbers or the airfoil tips even with lower steam flows, even with lower steam flows than what the Mitsubishi fleet had experienced. I think that that shows that there wasn't enough design margin in the blades.

Q And can you describe the failure of design margin in any order of magnitude?

A I don't have a percentage for that. No.
Q Or any narrative description for it?
A I think it would be difficult to do that without testing with instrumentation and breaking them on purpose with instrumentation hooked up so that you could see when they break, and you know what all the different parameters were at the point of the failure occurring.
Q I want to shift a little bit and talk about the blade a little bit. You guys were running a blade which I have gone over and looked at. It is pretty heavy.
A It is.
Q Do you know if Mitsubishi made that blade or whether they had it made by a subcontractor and had it casted by a third party?
A It's my understanding that Mitsubishi does that themselves.
Q Okay. Are you aware that in the turbine business, that some turbine blades are made by third parties?
A I am.
Q But you got affirmation that Mitsubishi said, no, it's on us, this is our blade?
A That's my understanding.

Q Okay. And do you know if that blade was cast in a single casting? Do you know what I mean by single casting?

A I do. I don't know the specifics of the manufacturing process.

Q Right. So just to make sure we are on the same page. Like a single casting is you got a form and you put in the metal, and then it hardens and that's it, and you don't have to weld anything else on to it, correct?

A Oh, so I do know the answer then. It's not a single casting.

Q And the things that were breaking off, I looked at that, they looked to me like they were welded on; is that right?

A I believe they are, yes. And there is other pieces like the tip of the airfoil, I believe, is not part of the forge, the original forging.

Q Right. So from the engineering standpoint, when you weld something on and you have a single form that's cast, the weakest part is where something has been welded on, all other things being equal; correct?

A There are certainly stress risers that at the heat affected zone of a weld. That doesn't mean necessarily that it's the weakest point, though. And in the case of these blades, it didn't fail at the heat affected zone in the weld. The snubbers and the Z-locks failed near the tips, not near the welds.

Q So when you say the snubbers and -- just can you go point just so we know exactly what --

MR. MOYLE: If I could approach, Your Honor?

THE COURT: Sure.

THE WITNESS: So the mid-span snubbers, this being the span of the blade, the mid-span snubbers are these pieces, and then the airfoil tips, or the Z-locks, are these pieces up here, the tips.

BY MR. MOYLE:

Q Okay. And the mid what do you call them?

A Mid-span snubbers.

Q Yeah. They look like they are welded on, right?

A I believe they are, yes.

Q The same with the ones on the top?

A Yes.

Q All right. So is that -- in your business, is that maybe not such a big surprise, that the piece is welded on?

A That is not a surprise. That's correct.

Q That happens?

A That's right.

Q And all other things being equal, wouldn't you think it's more likely that for that to happen if you are running at a higher frequency rate than at a lower frequency rate?

A That what would happen?

Q That you would have a failure just with respect to vibration?

A If something were welded on?

Q Or not, just in terms of, you know, if you are running something, you know, at 150 percent of its capacity compared to 80 percent of its capacity, all other things being equal, isn't it more likely that something being run at 150 percent of its capacity is more likely to have a problem?

A That could lead to problems, I agree, but I don't agree with the idea that the heat affected zone of a weld makes it necessarily the weak point. I think you went back to that.

Q Okay. And just so we have a clear record, I mean, the operations of the unit in question during Period 1, those were run for a pretty extended period of time. They were run more often over the 420-megawatt nameplate rating as compared to other periods in time, correct?

A That's correct.

Q I saw something in one of the documents that said about 15 percent of the time. Does that sound about right to you?

A It does, yes.

Q Yeah, okay. What's blending?

A Blending operation in a combined cycle -- remember that there is inherent flexibility in a combined cycle operation, and Bartow is a 4-on-1. So the transition between operating in 4-on-1 or 3-on-1 to 2-on-1 to 1-on-1, any time you do that, you have to -- let's use an example.

If you are going from 2-on-1 configuration to 3-on-1 configuration, so that means two combustion turbines operating with a steam turbine in service. You start up the third combustion turbine. You are generating electricity with the combustion turbine generator. The exhaust, remember, is going out the stack. It's not going to the HRSG yet. When you start -- then you start warming up the heat recovery steam generator. You start generating steam. You don't immediately put the steam into the turbine. You have to wait for certain conditions to be met on the steam. You don't want to put water in the steam turbine.

So what you do is you bypass steam to the condenser, and then once steam conditions are met, you start slowly blending. You start increasing the percentage of steam that's input to the steam turbine, so more to the steam turbine, less to the condenser until all of it is going into the steam turbine.

If you are going from 3-on-1 to 2-on-1 configuration, it's just the opposite. You start taking it out of the steam turbine and bypassing steam to the condenser, and then you shut down the HRSG and start exhausting out to the atmosphere.

Q And this is a 4-on-1, right?

A This is a 4-on-1.

Q But you can run it 3-on-1, 2-on-1?

A We can run it in any of those other combinations.

Q So if you are not blending, you know, the way you are supposed to do it, the way you described it, what are the consequences of that?

A Well, that's something we looked at in the root cause. In fact, Duke Energy made up our own definition of what a high-energy blend was because that's a possibility that that could exert more energy on the L0 blades because, as I described, there is steam flow that's being put into the condenser. It goes into the condoner nearby the L0 blades, so that's something we needed to look at.

Because there is no industry standard for the amount of energy that's put in the condenser during a blend, we looked at a lot of data. We came up with a method for classifying and a definition for high energy, and it was just based on the change in temperature over a certain period of time. More than a certain change in temperature in a minute's time, we said, let's just call that high energy, and it happens so many times over -- if you have this many blends, we see that -- this many of the blends, a percentage of the blend.

And then we were, because we made that definition, we were able to look around industry at both our -- at our combined -- other combined cycles, Mitsubishi or non-Mitsubishi units, and compare, is the energy of the blends at Bartow out of line with the rest of the unit -- what we see in the rest of our fleet? Is that change in temperature over a period of time greater, which could put in more energy into the condenser which could be negatively impacting the blades? And what we found is about consistent at Bartow with other units.

Q Yeah. And when you did that analysis, a lot of people are running combined cycle units, right?

A Oh, yes.

Q I mean, if we were to hazard a guess in this

country how much of the energy is supplied by combined cycle units, what would you say, 40, 50 percent?

A It's growing. It's probably 40-ish percent, plus or minus.

Q Yeah. There was something that caught my eye in one of the documents Mr. Rehwinkel was discussing with you, and I will refer it to you. It's on his Exhibit 115, and it's on Tab No. 6, and it's on Bates number 49.

A Okay. I am there.

Q And there is -- about middle of the page there it says, blending operation, do you see that?

A Yes.

Q Just read the quote, if you would, underneath there.

A It says: We've had bad blends during all five periods of operation.

Q Yeah. And you said you came up with a definition for the energy. I mean, what's a bad blend? I assume that's something that's not good just by the term, right?

A Yeah. I would say this is a good example of why this is a draft document, and why we go through a lot of iterations before putting out a final document. But I believe that the term bad is being used here in place of high-energy.

During the course of this root cause, we were developing this high energy blend definition. Maybe we didn't have it at this time. I don't know. I don't want to speculate, but I believe it means the same thing as a high-energy blend.

Q Do you know who came up with that word, which member of the seven-member team?

A I do not.

Q Did you ever talk to anybody about what that meant, or are you just kind of saying, oh, I think it means high-energy and surmising that?

A I don't know.

Q Yeah.

A I didn't have that discussion.

Q And that's fair, because you didn't, you know, you didn't work on the report. You weren't in all those meetings.

A Correct.

Q Okay. I just want to make sure the record is clear. When these problems occurred, you opted to just run the Bartow facility on the simple cycle, not combined cycle, right?

A During the periods when we were replacing blades, we were running in simple cycle mode. I don't know how many of the simple cycles were in operation. It changes the economics of those units. They are much less efficient obviously in simple cycle mode. So they are placed in our dispatch order changes. And then based on what the system load is on any given day, they may or may not be asked to run, but there is always at least one in service, I know, during all these time periods.

Q Yeah. So just in terms of the impact on efficiency, just give the judge an idea about the negative effect on efficiency if you are only running it in simple cycle and not using the heat recovery system, the HRSG system, which you have done as a result of some of these issues, correct?

A Correct.

Q So just is it about a third -- is the heat recovery system about a third? Use the 420 nameplate, what would you not realize not being able to run it in the combined cycle mode?

A Well, from a production standpoint, it was about -- oh, when the steam turbine was not in service?

Q Right.

A When the steam turbine was not in service, we are missing that 380 to 420 megawatts, depending on where we were running at the time. The combustion