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September 2, 2022

VIA: ELECTRONIC FILING

Mr. 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; FPSC Docket No. 20220001-EI

Dear Mr. Teitzman:

Attached for filing in the above docket is Tampa Electric Company's Projection Testimony and Exhibits for the period January 2023 through December 2023, including:

1. Petition of Tampa Electric Company;
2. Prepared Direct Testimony of M. Ashley Sizemore and Exhibit MAS-3;
3. Prepared Direct Testimony and Patrick A. Bokor and Exhibit PAB-2;
4. Prepared Direct Testimony of John C. Heisey;
5. Prepared Direct Testimony of Benjamin F. Smith II;
6. Prepared Direct Testimony of Penelope A. Rusk.

Thank you for your assistance in connection with this matter.

Sincerely,

Malcolm N. Means

Malcolm N. Means

MNM/ne
Attachment

cc: All Parties of Record (w/encl.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	))))	DOCKET NO. 20220001-EI FILED: September 2, 2022

PETITION OF TAMPA ELECTRIC COMPANY

Tampa Electric Company ("Tampa Electric" or "company"), hereby petitions the Commission for approval of the company's proposals concerning fuel and purchased power factors, capacity cost factors, Optimization Mechanism results, and generating performance incentive factors set forth herein, and in support thereof, says:

Fuel and Purchased Power Factors

1. Due to the current volatility in the natural gas commodity market Tampa Electric proposes to monitor the natural gas prices and 2022 under-recovery until the amount of the under-recovery can be estimated with greater certainty. The company will not include the 2022 under-recovery in its proposed 2023 cost recovery factors at this time and plans to make a request to recover the 2022 under-recovery at a later time. Therefore, the company has not included a projected fuel and purchased power net true-up amount for the period January 1, 2022 through December 31, 2022 in the calculation of the 2023 factors as shown on the attached schedules. This is shown in Exhibit No. MAS-3, Document No. 2, Schedule E1-C.

2. The company's projected expenditures for the period January 1, 2023 through December 31, 2023, when adjusted for the proposed GPIF reward, Optimization Mechanism sharing, spread over projected kilowatt-hour sales for the period January 1, 2023 through December 31, 2023, produce a fuel and purchased power factor for the new period of 4.832 cents

per kWh before the application of time of use multipliers for on-peak or off-peak usage. (See Exhibit No. MAS-3, Document No. 2, Schedule E1-E).

Capacity Cost Factor

3. Tampa Electric estimates that its net true-up amount applicable for the period January 1, 2022 through December 31, 2022 will be an over-recovery of $3,123,211, as shown in Exhibit No. MAS-3, Document No. 1, page 2 of 4.

4. The company's projected expenditures for the period January 1, 2023 through December 31, 2023, when adjusted for the true-up under-recovery amount and spread over projected kilowatt-hour sales for the period, produce a capacity cost recovery factor for the period of (0.016) cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is ($0.06), ($0.05), and ($0.04) per billed kW for GSD/RSD, GSLDPR/GSLDTPR, and GSLDSU/GSLDTSU rate classes, respectively, as set forth in Exhibit No. MAS-3, Document No. 1, page 3 of 4.

GPIF

5. Tampa Electric has calculated that it has earned a GPIF reward of $546,170 for performance during the period January 1, 2021 through December 31, 2021, included in Exhibit No. MAS-3, Document No. 2, Schedule E1-C.

6. The company is also proposing GPIF targets and ranges for the period January 1, 2023 through December 31, 2023 with such proposed targets and ranges being detailed in the testimony and exhibits of Tampa Electric witness Patrick A. Bokor filed herewith.

Optimization Mechanism

7. Tampa Electric has calculated that it is subject to an Optimization Mechanism sharing amount of $4,819,866, included in Exhibit No. MAS-3, Document No. 2, Schedule E1-C.

WHEREFORE, Tampa Electric Company requests that its proposals relative to fuel and purchased power cost recovery, capacity cost recovery, Optimization Mechanism sharing, and GPIF be approved as they relate to prior period true-up calculations and projected cost recovery charges.

DATED this 2nd day of September 2022.

Respectfully submitted,

Malcolm N. Means

J. JEFFRY WAHLEN
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VIRGINIA PONDER
Ausley McMullen
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(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Projection Testimony and Exhibits, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 2nd day of September 2022 to the following:

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Malcolm N. Means
ATTORNEY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY AND EXHIBIT
OF
M. ASHLEY SIZEMORE

FILED: SEPTEMBER 2, 2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

Q. Please state your name, address, occupation, and employer.

A. My name is M. Ashley Sizemore. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs department.

Q. Have you previously filed testimony in Docket No. 20220001-EI?

A. Yes, I submitted direct testimony on April 1, 2022 and July 27, 2022.

Q. Has your job description, education, or professional experience changed since you last filed testimony in this docket?

A. No, they have not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, and the proposed annual levelized fuel and purchased power cost recovery factors for January 2023 through December 2023. I also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2023.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. Exhibit No. MAS-3, consisting of three documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors. Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, includes Schedules E1 through E10 for January 2023 through December 2023 as well as Schedule H1 for 2020 through 2023. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate, which demonstrates that the tiered rate is revenue neutral.

Q. Are you requesting Commission approval of the projected fuel and capacity cost recovery factors for the company’s various rate schedules?

A. Yes.

Q. How were the fuel and capacity cost recovery clause factors calculated?

A. The fuel and capacity cost recovery factors were calculated as shown on Document Nos. 1 and 2. These factors were calculated based on the current approved rate design and schedules as set out in the 2021 Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-2021-0423-S-EI on November 10, 2021 in Docket No. 20210034-EI.

Capacity Cost Recovery

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company’s various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. MAS-3, Document No. 1, page 3 of 4.

Q. What payments are included in Tampa Electric's capacity cost recovery factors?

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. MAS-3, Document No. 1, page 2 of 4, Tampa Electric is refunding $3,123,211 after jurisdictional separation, prior year true-up, and application of the revenue tax factor for estimated expenses in 2023.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level effective beginning in January 2023 for which Tampa Electric is seeking approval.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor $ per kW
RS Secondary	-0.018	
GS and CS Secondary	-0.017	
GSD, SBD Standard		

Secondary		-0.06
Primary		-0.06
Transmission		-0.06
GSD Optional		
Secondary	-0.014	
Primary	-0.014	
Transmission	-0.014	
GSLDPR/GSLDTPR/SBLDPR/SBLDTSU		-0.05
GSLDSU/GSLDTSU/SBLDSU/SBLDTSU		-0.04
LS1 Secondary	-0.003	

These factors are shown in Exhibit No. MAS-3, Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of (0.016) cents per kWh compare to the factor for April 2022 through December 2022?

A. The proposed capacity cost recovery factor of (0.016) cents per kWh beginning in January 2023 is 0.061 cents per kWh (or $.61 per 1,000 kWh) less than the average capacity cost recovery factor of 0.045 cents per kWh for the April 2022 through December 2022 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the period beginning in January 2023?

A. The appropriate amount for the period beginning in January 2023 is 4.832 cents per kWh before the application of the time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. MAS-3, Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2023 through December 2023.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF"), true-up factors, and Optimization Mechanism factor are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $546,170 and an Optimization Mechanism gain of $4,819,866, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up for 2022 to be $0.

Q. Do your 2023 factors include the projected under-recovery for 2022?

A. No. Natural gas prices remain highly volatile, and the 2022 under-recovery could change materially over the remainder of the calendar year. Consequently, the company did not include the currently projected under-recovery for 2022 in the factors for 2023.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric’s on-peak and off-peak fuel adjustment factors for January 2023 through December 2023. The schedule also presents Tampa Electric’s levelized fuel cost factors at each metering level.

Q. Please describe the information presented on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak, and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. MAS-3, Document No. 3 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for the period beginning in January 2023.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	4.832
Tier I (Up to 1,000 kWh)	4.525
Tier II (Over 1,000 kWh)	5.525
Distribution Primary	4.784
Transmission	4.735
Lighting Service	4.767
Distribution Secondary	5.179(on-peak)
	4.683(off-peak)
Distribution Primary	5.127(on-peak)
	4.636(off-peak)
Transmission	5.075(on-peak)

4.589(off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 4.832 cents per kWh compare to the levelized fuel adjustment factor for the April 2022 through December 2022 period?

A. The proposed fuel charge factor of 4.832 cents per kWh is 0.706 cents per kWh (or $7.06 per 1,000 kWh) higher than the average fuel charge factor of 4.126 cents per kWh for the April 2022 through December 2022 period.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric project a 2023 wholesale incentive benchmark that is derived in accordance with Order No. PSC-2001-2371-FOF-EI issued in Docket No. 20010283-EI?

A. No. Effective January 1, 2018, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017, the company's Optimization Mechanism replaced the short-term wholesale sales incentive mechanism, and as a result no wholesale incentive benchmark is required for the 2023 projection.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric’s proposed changes in its base, capacity, fuel and purchased power, environmental, and energy conservation cost recovery factors on a 1,000 kWh residential customer’s bill?

A. The composite effect on a residential bill for 1,000 kWh is an increase of $14.20 in the period beginning January 2023, when compared to the April 2022 through December 2022 charges. These amounts are shown in Exhibit No. MAS-3, Document No. 2, on Schedule E10.

Q. When should the new rates take effect?

A. The new rates should take effect concurrent with meter readings for the first billing cycle for January 2023.

Q. Does this conclude your direct testimony?

A. Yes.

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2023 - DECEMBER 2023

AND

SCHEDULE E12

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2023 THROUGH DECEMBER 2023
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	53.95%	9,986,591	2,113	1.07443	1.05243	10,510,207	2,271	50.16%	59.19%	58.49%
GS, CS	57.87%	912,160	180	1.07443	1.05241	959,970	193	4.58%	5.03%	5.00%
GSD Optional	3.96%	370,822	57	1.07347	1.05132	389,854	61	1.86%	1.59%	1.61%
GSD, SBD, RSD	70.93%	6,640,888	1,012	1.07347	1.05132	6,981,713	1,087	33.32%	28.33%	28.71%
GSLDPR/SBLDTPR	104.98%	1,256,480	137	1.04490	1.02631	1,289,536	143	6.15%	3.73%	3.92%
GSLDSU/SBLDTSU	102.86%	700,733	78	1.02670	1.01426	710,728	80	3.39%	2.08%	2.18%
LS1, LS2	879.82%	107,962	1	1.07443	1.05243	113,622	2	0.54%	0.05%	0.09%
TOTAL		19,975,636	3,578			20,955,630	3,837	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2022 projected calendar data.
(2) Projected MWH sales for the period January 2023 thru December 2023.
(3) Based on 12 months average CP at meter.
(4) Based on 2022 projected demand losses.
(5) Based on 2022 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 2023 THROUGH DECEMBER 2023
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	0	0	0	0	283,354	283,354	283,354	283,354	283,354	283,354	0	0	1,700,124
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(UNIT POWER CAPACITY REVENUES)	(71,105)	(71,105)	(71,105)	(71,105)	(71,105)	(71,105)	(71,105)	(71,105)	(71,105)	(71,105)	(71,105)	(71,107)	(853,262)
4	TOTAL CAPACITY DOLLARS	($71,105)	($71,105)	($71,105)	($71,105)	$212,249	$212,249	$212,249	$212,249	$212,249	$212,249	($71,105)	($71,107)	$846,862
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	($71,105)	($71,105)	($71,105)	($71,105)	$212,249	$212,249	$212,249	$212,249	$212,249	$212,249	($71,105)	($71,107)	$846,862
7	ESTIMATED TRUE-UP FOR THE PERIOD ENDING DECEMBER 2022													(3,967,826)
8	TOTAL													($3,120,964)
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													($3,123,211)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2023 THROUGH DECEMBER 2023
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	50.16%	59.19%	(120,472)	(1,706,469)	(1,826,941)	9,986,591	9,986,591				-0.00018
GS, CS	4.58%	5.03%	(11,000)	(145,017)	(156,017)	912,160	912,160				-0.00017
GSD, RSD											
Secondary						6,338,665	6,338,665			-0.06	
Primary						300,573	297,567			-0.06	
Transmission						1,651	1,618			-0.06	
GSD, RSD - Standard	33.32%	28.33%	(80,026)	(816,764)	(896,790)	6,640,888	6,637,850	57.50%	15,814,264		
GSD - Optional	1.86%	1.59%	(4,467)	(45,840)	(50,307)						
Secondary						364,077	364,077				-0.00014
Primary						6,746	6,678				-0.00014
Transmission						0	0				-0.00014
GSLDPR/GSLDTPR SBLDPR/SBLDTPR	6.15%	3.73%	(14,771)	(107,537)	(122,308)	1,256,480	1,256,480	68.51%	2,512,434	-0.05	
GSLDSU/GSLDTSU SBLDSU/SBLDTSU	3.39%	2.08%	(8,142)	(59,967)	(68,109)	700,733	700,733	60.41%	1,588,948	-0.04	
LS1	0.54%	0.05%	(1,297)	(1,442)	(2,739)	107,962	107,962				-0.00003
TOTAL	100.00%	100.00%	(240,175)	(2,883,036)	(3,123,211)	19,975,636	19,972,529				-0.00016

(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 2023 through December 2023.
(7) Projected kWh sales at secondary for the period January 2023 through December 2023.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2023 through December 2023.
(10) Total Col (5) / Total Col (9).
(11) {Col (5) / Total Col (7)} / 1000.

REDACTED

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ESTIMATED FOR THE PERIOD: JANUARY 2023 THROUGH DECEMBER 2023

SCHEDULE E12

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	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
FLORIDA MUNICIPAL POWER AGENCY	[redacted]												
ORLANDO UTILITIES COMMISSION													
VARIOUS													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	(71,105)	(71,105)	(71,105)	(71,105)	212,249	212,249	212,249	212,249	212,249	212,249	(71,105)	(71,107)	846,862
TOTAL CAPACITY	**($71,105)**	**($71,105)**	**($71,105)**	**($71,105)**	**$212,249**	**$212,249**	**$212,249**	**$212,249**	**$212,249**	**$212,249**	**($71,105)**	**($71,107)**	**$846,862**

DOCKET NO. 20220001-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 2023 - DECEMBER 2023

SCHEDULES E1 THROUGH E10
SCHEDULE H1

TAMPA ELECTRIC COMPANY

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TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2023 THROUGH DECEMBER 2023

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	953,714,571	20,958,980	4.55039
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Adjustment	0	20,958,980 [(1)]	0.00000
4b.	Adjustment	0	0	0.00000
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**953,714,571**	**20,958,980**	**4.55039**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	18,870	190	9.93158
7.	Energy Cost of Economy Purchases (E9)	3,329,070	36,660	9.08093
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	1,787,820	64,970	2.75176
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**5,135,760**	**101,820**	**5.04396**
11.	**TOTAL AVAILABLE MWH (LINE 5 + LINE 10)**		**21,060,800**	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	1,937,530	40,120	4.82934
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	0	0	0.00000
14.	Gains on Sales	179,997	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**2,117,527**	**40,120**	**5.27798**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		1,372	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**956,732,804**	**21,019,308**	**4.55169**
20.	Net Unbilled	NA [(1)(a)]	NA [(a)]	NA
21.	Company Use	1,747,849 [(1)]	38,400	0.00876
22.	T & D Losses	46,765,269 [(1)]	1,027,426	0.23437
23.	System MWH Sales	956,732,804	19,953,481	4.79482
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	956,732,804	19,953,481	4.79482
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	956,732,804	19,953,481	4.79482
28.	Optimization Mechanism[(2)]	4,819,866	19,953,481	0.02416
29.	True-up [(2)]	0	19,953,481	0.00000
30.	Total Jurisdictional Fuel Cost (Excl. GPIF)	961,552,670	19,953,481	4.81897
31.	Revenue Tax Factor			1.00072
32.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	962,244,988	19,953,481	4.82244
33.	GPIF Adjusted for Taxes [(2)]	546,170	19,953,481	0.00274
34.	**Fuel Factor Adjusted for Taxes Including GPIF**	962,791,158	19,953,481	4.82518
35	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**4.825**

(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 2023 THROUGH DECEMBER 2023

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2022 - December 2022 (6 months actual, 6 months estimated)	($437,178,107)
2.	PROJECTED OVER/UNDER-RECOVERY TRUE-UP INCLUDED IN APRIL - DECEMBER 2022 RATES (Per Mid-Course correction Schedule E1-C, line 1B)	($97,303,593)
3.	DIFFERENCE IN 2021 ESTIMATED TRUE-UP AMOUNT PROJECTED IN MID-COURSE 2022 RATES AND AMOUNT COLLECTED IN 2022 ($72,171,466 under-recovery less ($81,354) collected January through March 2022)	($72,090,112)
4.	ACTUAL-ESTIMATED 2022 OVER/(UNDER) RECOVERY (Line 1 - Line 2 + Line 3)	($411,964,625)
5.	FINAL TRUE-UP (January 2021 - December 2021) (Per True-Up filed April 1, 2022)	0
6.	TOTAL OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2023 (Line 4 + Line 5) To be included in the 12-month projected period January 2023 through December 2023 (2023 Schedule E1, line 29)	$0
7.	JURISDICTIONAL MWH SALES (Projected January 2023 through December 2023)	19,953,481
8.	TRUE-UP FACTOR - cents/kWh (Using Effective MWh Sales of 19,923,795)	**0.0000**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2023 THROUGH DECEMBER 2023

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2023 through December 2023)	$546,170	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2023 through December 2023)	$0	
	C. OPTIMIZATION MECHANISM GAIN / (LOSS) (January 2023 through December 2023)	$4,819,866	
2.	TOTAL SALES (January 2023 through December 2023)	19,953,481	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR (Using Effective MWh Sales of 19,923,795)	**0.0027**	Cents/kWh
	B. TRUE-UP FACTOR (Using Effective MWh Sales of 19,923,795)	**0.0000**	Cents/kWh
	C. OPTIMIZATION MECHANISM FACTOR (Using Effective MWh Sales of 19,923,795)	**0.0242**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2023 THROUGH DECEMBER 2023

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	30.09	$38.30
OFF PEAK	69.91	$34.63
	100.00	1.1060

			TOTAL		ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$956,732,804			
2	MWH Sales (Jurisd)	(Sch E1 line 25)	19,953,481			
2a	Effective MWH Sales (Jurisd)		19,923,795			
3	Cost Per KWH Sold	(line 1 / line 2)	4.7948			
4	Jurisdictional Loss Factor		1.00000			
5	Jurisdictional Fuel Factor		NA			
6	True-Up	(Sch E1 line 29)	$0			
7	Optimization Mechanism	(Sch E1 line 28)	$4,819,866			
8	TOTAL	(line 1 x line 4) + line 6 + line 7	$961,552,670			
9	Revenue Tax Factor		1.00072			
10	Recovery Factor	(line 8 x line 9) / line 2a / 10	4.8296			
11	GPIF Factor	(Sch E1-C line 3A)	0.0027			
12	Recovery Factor Including GPIF	(line 10 + line 11)	4.8323		5.1793	4.683
13	Recovery Factor Rounded to the Nearest .001 cents/KWH		4.832		5.179	4.683
14	Hours: ON PEAK			25.59%		
15	OFF PEAK			74.41%		
				100.00%		

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Line Loss	Secondary
Distribution Secondary	17,687,299		17,687,299
Distribution Primary	1,563,798	0.99	1,548,160
Transmission	702,384	0.98	688,336
Total	19,953,481		19,923,795

	Standard	On-Peak	Off-Peak
Distribution Secondary	4.832	5.179	4.683
Distribution Primary	4.784	5.127	4.636
Transmission	4.735	5.075	4.589
RS 1st Tier	4.525		
RS 2nd Tier	5.525		
Lighting	4.767		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2023 THROUGH DECEMBER 2023

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)		4.525	5.525
Distribution Secondary	4.832		
Distribution Primary	4.784		
Transmission	4.735		
Lighting Service (1)	4.767		
TIME-OF-USE			
Distribution Secondary - On-Peak	5.179		
Distribution Secondary - Off-Peak	4.683		
Distribution Primary - On-Peak	5.127		
Distribution Primary - Off-Peak	4.636		
Transmission - On-Peak	5.075		
Transmission - Off-Peak	4.589		

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

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2023 THROUGH DECEMBER 2023

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
						ESTIMATED							TOTAL
	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	PERIOD
1. Fuel Cost of System Net Generation	97,901,703	84,987,682	80,591,341	65,478,460	75,352,417	81,905,386	87,315,870	89,715,675	82,918,437	77,998,360	61,682,842	67,866,398	953,714,571
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold (1)	289,859	286,460	229,782	115,061	150,099	115,880	125,399	137,006	188,722	161,771	171,804	145,684	2,117,527
4. Fuel Cost of Purchased Power	5,080	0	0	0	0	0	0	0	0	0	0	13,790	18,870
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	183,860	162,520	144,580	132,170	152,920	141,350	164,850	138,020	146,150	141,890	130,070	149,440	1,787,820
7. Energy Cost of Economy Purchases	132,290	0	72,950	24,840	64,420	64,480	57,670	165,710	1,341,690	714,780	466,690	223,550	3,329,070
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	**97,933,074**	**84,863,742**	**80,579,089**	**65,520,409**	**75,419,658**	**81,995,336**	**87,412,991**	**89,882,399**	**84,217,555**	**78,693,259**	**62,107,798**	**68,107,494**	**956,732,804**
11. Jurisdictional MWH Sold	1,512,552	1,387,952	1,366,922	1,449,850	1,618,094	1,857,135	1,952,000	1,957,588	2,008,757	1,845,885	1,550,632	1,446,115	19,953,481
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)	97,933,074	84,863,742	80,579,089	65,520,409	75,419,658	81,995,336	87,412,991	89,882,399	84,217,555	78,693,259	62,107,798	68,107,494	956,732,804
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)	**97,933,074**	**84,863,742**	**80,579,089**	**65,520,409**	**75,419,658**	**81,995,336**	**87,412,991**	**89,882,399**	**84,217,555**	**78,693,259**	**62,107,798**	**68,107,494**	**956,732,804**
16. Cost Per kWh Sold (Cents/kWh)	6.4747	6.1143	5.8949	4.5191	4.6610	4.4152	4.4781	4.5915	4.1925	4.2632	4.0053	4.7097	4.7948
17. Optimization Mechanism (Cents/kWh) (2)	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242
18. True-up (Cents/kWh) (2)	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
19. Total (Cents/kWh) (Line 16+17+18)	6.4989	6.1385	5.9191	4.5433	4.6852	4.4394	4.5023	4.6157	4.2167	4.2874	4.0295	4.7339	4.8190
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)	6.5036	6.1429	5.9234	4.5466	4.6886	4.4426	4.5055	4.6190	4.2197	4.2905	4.0324	4.7373	4.8225
22. GPIF Adjusted for Taxes (Cents/kWh) (2)	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027
23. TOTAL RECOVERY FACTOR (LINE 21+22)	**6.5063**	**6.1456**	**5.9261**	**4.5493**	**4.6913**	**4.4453**	**4.5082**	**4.6217**	**4.2224**	**4.2932**	**4.0351**	**4.7400**	**4.8252**
24. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**6.506**	**6.146**	**5.926**	**4.549**	**4.691**	**4.445**	**4.508**	**4.622**	**4.222**	**4.293**	**4.035**	**4.740**	**4.825**

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

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2023 THROUGH JUNE 2023

SCHEDULE E3

	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	94,382	94,428	94,473	94,517	94,561	94,604
3. COAL	7,572,646	2,332,840	3,095,472	0	0	2,688,592
4. NATURAL GAS	90,234,675	82,560,414	77,401,396	65,383,943	75,257,856	79,122,190
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**97,901,703**	**84,987,682**	**80,591,341**	**65,478,460**	**75,352,417**	**81,905,386**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	300	300	300	300	300	300
10. COAL	232,250	66,200	84,590	0	0	61,670
11. NATURAL GAS	1,166,980	1,159,580	1,239,020	1,343,100	1,605,430	1,700,360
12. SOLAR	144,810	162,350	199,140	249,240	275,250	236,210
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,544,340**	**1,388,430**	**1,523,050**	**1,592,640**	**1,880,980**	**1,998,540**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	665	665	665	665	665	665
17. COAL (TON)	107,170	30,760	39,630	0	0	31,490
18. NATURAL GAS (MCF)	8,078,345	7,825,885	8,544,725	9,028,365	10,775,735	11,452,675
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	3,900	3,900	3,900	3,900	3,900	3,900
23. COAL	2,411,430	691,990	891,780	0	0	708,510
24. NATURAL GAS	8,295,110	8,045,030	8,768,550	9,281,190	11,077,480	11,760,920
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**10,710,440**	**8,740,920**	**9,664,230**	**9,285,090**	**11,081,380**	**12,473,330**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.02	0.02	0.02	0.02	0.02
30. COAL	15.04	4.77	5.55	0.00	0.00	3.08
31. NATURAL GAS	75.56	83.52	81.35	84.33	85.35	85.08
32. SOLAR	9.38	11.69	13.08	15.65	14.63	11.82
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)	141.93	142.00	142.06	142.13	142.20	142.26
37. COAL ($/TON)	70.66	75.84	78.11	0.00	0.00	85.38
38. NATURAL GAS ($/MCF)	11.17	10.55	9.06	7.24	6.98	6.91
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 ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	24.20	24.21	24.22	24.24	24.25	24.26
43. COAL	3.14	3.37	3.47	0.00	0.00	3.79
44. NATURAL GAS	10.88	10.26	8.83	7.04	6.79	6.73
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**9.14**	**9.72**	**8.34**	**7.05**	**6.80**	**6.57**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	13,000	13,000	13,000	13,000	13,000	13,000
50. COAL	10,383	10,453	10,542	0	0	11,489
51. NATURAL GAS	7,108	6,938	7,077	6,910	6,900	6,917
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**6,935**	**6,296**	**6,345**	**5,830**	**5,891**	**6,241**
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	31.46	31.48	31.49	31.51	31.52	31.53
57. COAL	3.26	3.52	3.66	0.00	0.00	4.36
58. NATURAL GAS	7.73	7.12	6.25	4.87	4.69	4.65
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)	**6.34**	**6.12**	**5.29**	**4.11**	**4.01**	**4.10**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2023 THROUGH DECEMBER 2023

SCHEDULE E3

		Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	94,646	94,676	94,691	94,693	94,683	94,663	1,135,017
3.	COAL	3,034,523	3,900,479	5,857,911	6,864,534	2,516,837	3,142,712	41,006,546
4.	NATURAL GAS	84,186,701	85,720,520	76,965,835	71,039,133	59,071,322	64,629,023	911,573,008
5.	SOLAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**87,315,870**	**89,715,675**	**82,918,437**	**77,998,360**	**61,682,842**	**67,866,398**	**953,714,571**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	300	300	300	300	300	300	3,600
10.	COAL	69,140	86,950	133,980	154,380	54,910	69,010	1,013,080
11.	NATURAL GAS	1,796,650	1,828,880	1,631,670	1,501,730	1,253,120	1,316,260	17,542,780
12.	SOLAR	229,700	222,010	191,890	190,960	147,780	150,180	2,399,520
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**2,095,790**	**2,138,140**	**1,957,840**	**1,847,370**	**1,456,110**	**1,535,750**	**20,958,980**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	665	665	665	665	665	665	7,980
17.	COAL (TON)	35,080	44,270	66,390	77,130	28,050	34,800	494,770
18.	NATURAL GAS (MCF)	12,118,035	12,354,675	11,012,615	10,022,165	8,353,255	8,848,985	118,415,460
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	3,900	3,900	3,900	3,900	3,900	3,900	46,800
23.	COAL	789,390	996,120	1,493,790	1,735,530	631,050	782,960	11,132,550
24.	NATURAL GAS	12,450,060	12,688,170	11,315,810	10,300,620	8,581,980	9,089,460	121,654,380
25.	SOLAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**13,243,350**	**13,688,190**	**12,813,500**	**12,040,050**	**9,216,930**	**9,876,320**	**132,833,730**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.01	0.01	0.02	0.02	0.02	0.02	0.02
30.	COAL	3.30	4.07	6.84	8.35	3.77	4.49	4.83
31.	NATURAL GAS	85.73	85.54	83.34	81.29	86.06	85.71	83.70
32.	SOLAR	10.96	10.38	9.80	10.34	10.15	9.78	11.45
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)	142.32	142.37	142.39	142.40	142.38	142.35	142.23
37.	COAL ($/TON)	86.50	88.11	88.23	89.00	89.73	90.31	82.88
38.	NATURAL GAS ($/MCF)	6.95	6.94	6.99	7.09	7.07	7.30	7.70
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 ($/MMBTU)								
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	24.27	24.28	24.28	24.28	24.28	24.27	24.25
43.	COAL	3.84	3.92	3.92	3.96	3.99	4.01	3.68
44.	NATURAL GAS	6.76	6.76	6.80	6.90	6.88	7.11	7.49
45.	SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	**TOTAL ($/MMBTU)**	**6.59**	**6.55**	**6.47**	**6.48**	**6.69**	**6.87**	**7.18**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	13,000	13,000	13,000	13,000	13,000	13,000	13,000
50.	COAL	11,417	11,456	11,149	11,242	11,492	11,346	10,989
51.	NATURAL GAS	6,930	6,938	6,935	6,859	6,848	6,906	6,935
52.	SOLAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**6,319**	**6,402**	**6,545**	**6,517**	**6,330**	**6,431**	**6,338**
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	31.55	31.56	31.56	31.56	31.56	31.55	31.53
57.	COAL	4.39	4.49	4.37	4.45	4.58	4.55	4.05
58.	NATURAL GAS	4.69	4.69	4.72	4.73	4.71	4.91	5.20
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)**	**4.17**	**4.20**	**4.24**	**4.22**	**4.24**	**4.42**	**4.55**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2023

(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	19.7	190	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	2,850	273.6	-	273.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	9,740	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,080	18.3	-	18.3	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	12,230	22.1	-	22.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.9	8,340	18.4	-	18.4	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	55.2	7,640	18.6	-	18.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,410	19.4	-	19.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.3	6,440	17.6	-	17.6	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,420	20.5	-	20.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,170	22.0	-	22.0	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,560	19.2	-	19.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	31.4	3,570.0	15.3	-	15.3	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	6,200.0	11.2	-	11.2	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	54.4	8,450.0	20.9	-	20.9	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	8,450.0	15.3	-	15.3	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	14.2	6,270.0	59.3	-	59.3	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	55.0	6,970.0	17.0	-	17.0	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	1,590.0	3.1	-	3.1	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	61.0	7,970.0	17.6	-	17.6	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR	25.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR	60.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL	(3) **1321.5**	**144,810**	**14.7**	**-**	**14.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL	**335**	**710,780**	**285.2**	**0.0**	**292.2**	**6,298**	**GAS**	**4,354,780**	**1,028,001**	**4,476,720.0**	**48,642,656**	**6.84**	**11.17**
28. BIG BEND #2 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)	355	16,670	6.3	-	-	-	GAS	192,350	1,027,970	197,730.0	2,148,539	12.89	11.17
30. B.B.#3 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL	**355**	**16,670**	**6.3**	**82.1**	**7.0**	**11,861**		**-**	**-**	**197,730.0**	**2,148,539**	**12.89**	**-**
32. B.B.#4 (GAS)	420	40,980	13.1	-	-	-	GAS	413,950	1,028,023	425,550.0	4,623,799	11.28	11.17
33. B.B.#4 (COAL)	432	232,250	72.3	-	-	-	COAL	107,170	22,500,980	2,411,430.0	7,572,646	3.26	70.66
34. BIG BEND #4 TOTAL	**432**	**273,230**	**85.0**	**89.3**	**83.2**	**10,383**		**-**	**-**	**2,836,980.0**	**12,196,445**	**4.46**	**-**
35. B.B. IGNITION	-	-	-	-	-	-	GAS	9,190	1,028,292	9,450.0	102,652	-	11.17
36. B.B.C.T.#4 TOTAL	**61**	**30**	**0.1**	**98.3**	**24.6**	**19,667**	**GAS**	**570**	**1,035,088**	**590.0**	**6,367**	**21.22**	**11.17**
37. B.B.C.T.#5 TOTAL	**350**	**0**	**0.0**	**96.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL	**350**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL	**1,883**	**1,000,710**	**71.4**	**74.9**	**123.6**	**7,507**	**-**	**-**	**-**	**7,512,020.0**	**63,096,659**	**6.31**	**-**
40. POLK #1 GASIFIER	245	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)	220	10,950	6.7	-	77.8	8,942	GAS	95,250	1,027,927	97,910.0	1,063,937	9.72	11.17
42. POLK #1 TOTAL	**245**	**10,950**	**6.0**	**93.8**	**77.8**	**8,942**	**-**	**-**	**-**	**97,910.0**	**1,063,937**	**9.72**	**-**
43. POLK #2 ST DUCT FIRING	120	1,080	1.2	-	75.0	8,185	GAS	8,600	1,027,907	8,840.0	96,062	8.89	11.17
44. POLK #2 ST W/O DUCT FIRING	360	110,470	-	-	-	-		771,785	1,028,007	793,400.0	8,620,796	7.80	11.17
45. POLK #2 ST TOTAL	**480**	**111,550**	**31.2**	**-**	**70.6**	**7,192**	**GAS**	**-**	**-**	**802,240.0**	**8,716,858**	**7.81**	**-**
46. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
47. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	47,262	31.51	141.93
48. POLK #2 TOTAL	(4) **180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,262**	**31.51**	**-**
49. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
50. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	47,120	31.41	141.93
51. POLK #3 TOTAL	(4) **180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,120**	**31.41**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2023

(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)
52. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
53. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
54. POLK #2 CC TOTAL	**1,200**	**111,850**	**12.5**	**97.4**	**70.7**	**7,207**	**-**	**-**	**-**	**806,140.0**	**8,811,240**	**7.88**	**-**
55. POLK STATION TOTAL	**1,445**	**122,800**	**11.4**	**96.8**	**71.8**	**7,362**	**-**	**-**	**-**	**904,050.0**	**9,875,177**	**8.04**	**-**
56. BAYSIDE #1	792	159,320	27.0	96.6	28.0	7,843	GAS	1,215,490	1,027,997	1,249,520.0	13,576,957	8.52	11.17
57. BAYSIDE #2	1,047	115,800	14.9	97.3	15.5	8,923	GAS	1,005,120	1,027,997	1,033,260.0	11,227,136	9.70	11.17
58. BAYSIDE #3	61	200	0.4	98.6	65.6	12,900	GAS	2,500	1,032,000	2,580.0	27,925	13.96	11.17
59. BAYSIDE #4	61	150	0.3	98.6	61.5	13,200	GAS	1,930	1,025,907	1,980.0	21,558	14.37	11.17
60. BAYSIDE #5	61	290	0.6	98.6	67.9	12,966	GAS	3,660	1,027,322	3,760.0	40,882	14.10	11.17
61. BAYSIDE #6	61	260	0.6	98.6	71.0	12,577	GAS	3,170	1,031,546	3,270.0	35,409	13.62	11.17
62. BAYSIDE STATION TOTAL	**2,083**	**276,020**	**17.8**	**97.2**	**20.9**	**8,312**	**GAS**	**2,231,870**	**1,028,003**	**2,294,370.0**	**24,929,867**	**9.03**	**11.17**
63. SYSTEM TOTAL	**6,733**	**1,544,340**	**30.8**	**71.8**	**68.4**	**6,935**	**-**	**-**	**-**	**10,710,440.0**	**97,901,703**	**6.34**	**-**

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. 20220001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 11 OF 42

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2023

(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	19.7	190	1.4	-	1.4	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	3,030	322.1	-	322.1	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	11,240	23.9	-	23.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	11,670	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	13,030	26.1	-	26.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.9	9,270	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	55.2	8,480	22.9	-	22.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,780	23.0	-	23.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.3	7,430	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	12,050	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,870	25.8	-	25.8	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	9,880	24.6	-	24.6	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	31.4	4,130.0	19.6	-	19.6	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	7,160.0	14.3	-	14.3	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	54.4	9,770.0	26.7	-	26.7	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	9,770.0	19.6	-	19.6	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	14.2	7,240.0	75.9	-	75.9	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	55.0	8,050.0	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	1,840.0	3.9	-	3.9	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	61.0	9,210.0	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR	25.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR	60.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL	(3) **1321.5**	**162,350**	**18.3**	**-**	**18.3**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL	**335**	**697,560**	**309.9**	**0.0**	**317.4**	**6,277**	**GAS**	**4,259,610**	**1,028,003**	**4,378,890.0**	**44,937,431**	**6.44**	**10.55**
28. BIG BEND #2 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)	355	7,600	3.2	-	-	-	GAS	87,200	1,027,867	89,630.0	919,930	12.10	10.55
30. B.B.#3 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL	**355**	**7,600**	**3.2**	**48.5**	**10.6**	**11,793**		**-**	**-**	**89,630.0**	**919,930**	**12.10**	**-**
32. B.B.#4 (GAS)	420	11,680	4.1	-	-	-	GAS	118,790	1,028,033	122,120.0	1,253,194	10.73	10.55
33. B.B.#4 (COAL)	432	66,200	22.8	-	-	-	COAL	30,760	22,496,424	691,990.0	2,332,840	3.52	75.84
34. BIG BEND #4 TOTAL	**432**	**77,880**	**26.8**	**89.3**	**74.5**	**10,453**		**-**	**-**	**814,110.0**	**3,586,034**	**4.60**	**-**
35. B.B. IGNITION	-	-	-	-	-	-	GAS	0	0	0.0	0	-	0.00
36. 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**
37. B.B.C.T.#5 TOTAL	**350**	**0**	**0.0**	**94.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL	**350**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL	**1,883**	**783,040**	**61.9**	**68.3**	**197.7**	**6,746**	**-**	**-**	**-**	**5,282,630.0**	**49,443,395**	**6.31**	**-**
40. POLK #1 GASIFIER	245	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)	220	5,320	3.6	-	75.6	8,977	GAS	46,450	1,028,202	47,760.0	490,032	9.21	10.55
42. POLK #1 TOTAL	**245**	**5,320**	**3.2**	**93.8**	**75.6**	**8,977**	**-**	**-**	**-**	**47,760.0**	**490,032**	**9.21**	**-**
43. POLK #2 ST DUCT FIRING	120	200	0.2	-	83.3	8,150	GAS	1,580	1,031,646	1,630.0	16,668	8.33	10.55
44. POLK #2 ST W/O DUCT FIRING	360	173,510	-	-	-	-		1,204,015	1,028,010	1,237,740.0	12,701,947	7.32	10.55
45. POLK #2 ST TOTAL	**480**	**173,710**	**53.9**	**-**	**80.4**	**7,135**	**GAS**	**-**	**-**	**1,239,370.0**	**12,718,615**	**7.32**	**-**
46. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
47. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	47,285	31.52	142.00
48. POLK #2 TOTAL	(4) **180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,285**	**31.52**	**-**
49. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
50. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	47,143	31.43	142.00
51. POLK #3 TOTAL	(4) **180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,143**	**31.43**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2023

(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)
52. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
53. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
54. POLK #2 CC TOTAL	**1,200**	**174,010**	**21.6**	**97.4**	**80.4**	**7,145**	**-**	**-**	**-**	**1,243,270.0**	**12,813,043**	**7.36**	**-**
55. POLK STATION TOTAL	**1,445**	**179,330**	**18.5**	**96.8**	**80.1**	**7,199**	**-**	**-**	**-**	**1,291,030.0**	**13,303,075**	**7.42**	**-**
56. BAYSIDE #1	792	161,970	30.4	96.6	31.5	7,737	GAS	1,219,000	1,027,990	1,253,120.0	12,860,034	7.94	10.55
57. BAYSIDE #2	1,047	101,660	14.4	97.3	15.1	8,982	GAS	888,280	1,027,998	913,150.0	9,371,050	9.22	10.55
58. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
59. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
60. BAYSIDE #5	61	40	0.1	98.6	65.6	12,250	GAS	480	1,020,833	490.0	5,064	12.66	10.55
61. BAYSIDE #6	61	40	0.1	98.6	65.6	12,500	GAS	480	1,041,667	500.0	5,064	12.66	10.55
62. BAYSIDE STATION TOTAL	**2,083**	**263,710**	**18.8**	**91.4**	**22.2**	**8,218**	**GAS**	**2,108,240**	**1,027,995**	**2,167,260.0**	**22,241,212**	**8.43**	**10.55**
63. SYSTEM TOTAL	**6,733**	**1,388,430**	**30.7**	**68.2**	**79.1**	**6,296**	**-**	**-**	**-**	**8,740,920.0**	**84,987,682**	**6.12**	**-**

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

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2023

(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	19.7	250	1.7	-	1.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	4,040	388.4	-	388.4	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,210	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	13,700	24.9	-	24.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,210	31.2	-	31.2	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.9	11,010	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	55.2	10,080	24.6	-	24.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,240	29.7	-	29.7	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.3	8,740	23.9	-	23.9	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,390	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,290	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,700	26.3	-	26.3	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	31.4	4,830.0	20.7	-	20.7	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	8,380.0	15.2	-	15.2	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	54.4	11,430.0	28.3	-	28.3	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	11,430.0	20.7	-	20.7	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	14.2	8,480.0	80.4	-	80.4	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	55.0	9,440.0	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	2,160.0	4.2	-	4.2	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	61.0	10,800.0	23.8	-	23.8	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR	25.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR	60.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL	(3) **1321.5**	**199,140**	**20.3**	**-**	**20.3**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL	**335**	**649,430**	**260.9**	**0.0**	**318.3**	**6,280**	**GAS**	**3,967,290**	**1,028,001**	**4,078,380.0**	**35,937,234**	**5.53**	**9.06**
28. BIG BEND #2 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)	355	22,970	8.7	-	-	-	GAS	261,770	1,027,963	269,090.0	2,371,213	10.32	9.06
30. B.B.#3 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL	**355**	**22,970**	**8.7**	**82.1**	**23.9**	**11,715**		**-**	**-**	**269,090.0**	**2,371,213**	**10.32**	**-**
32. B.B.#4 (GAS)	420	14,930	4.8	-	-	-	GAS	153,090	1,027,957	157,370.0	1,386,748	9.29	9.06
33. B.B.#4 (COAL)	432	84,590	26.4	-	-	-	COAL	39,630	22,502,650	891,780.0	3,095,472	3.66	78.11
34. BIG BEND #4 TOTAL	**432**	**99,520**	**31.0**	**72.0**	**59.2**	**10,542**		**-**	**-**	**1,049,150.0**	**4,482,220**	**4.50**	**-**
35. B.B. IGNITION	-	-	-	-	-	-	GAS	15,030	1,027,944	15,450.0	136,148	-	9.06
36. B.B.C.T.#4 TOTAL	**61**	**10**	**0.0**	**98.3**	**16.4**	**29,000**	**GAS**	**280**	**1,035,714**	**290.0**	**2,536**	**25.36**	**9.06**
37. B.B.C.T.#5 TOTAL	**350**	**0**	**0.0**	**96.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL	**350**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL	**1,883**	**771,930**	**55.2**	**71.0**	**164.8**	**6,991**	**-**	**-**	**-**	**5,396,910.0**	**42,929,351**	**5.56**	**-**
40. POLK #1 GASIFIER	245	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)	220	8,580	5.2	-	75.0	8,978	GAS	74,930	1,028,026	77,030.0	678,745	7.91	9.06
42. POLK #1 TOTAL	**245**	**8,580**	**4.7**	**93.8**	**75.0**	**8,978**	**-**	**-**	**-**	**77,030.0**	**678,745**	**7.91**	**-**
43. POLK #2 ST DUCT FIRING	120	180	0.2	-	50.0	8,167	GAS	1,430	1,027,972	1,470.0	12,953	7.20	9.06
44. POLK #2 ST W/O DUCT FIRING	360	168,020	-	-	-	-		1,164,485	1,028,008	1,197,100.0	10,548,352	6.28	9.06
45. POLK #2 ST TOTAL	**480**	**168,200**	**47.2**	**-**	**81.3**	**7,126**	**GAS**	**-**	**-**	**1,198,570.0**	**10,561,305**	**6.28**	**-**
46. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	(1)	0.00	0.00
47. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	47,307	31.54	142.06
48. POLK #2 TOTAL	(4) **180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,306**	**31.54**	**-**
49. POLK #3 CT (GAS)	180	1,650	1.2	-	76.4	11,164	GAS	17,910	1,028,476	18,420.0	162,236	9.83	9.06
50. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	47,166	31.44	142.07
51. POLK #3 TOTAL	(4) **180**	**1,800**	**1.3**	**-**	**76.7**	**11,317**	**-**	**-**	**-**	**20,370.0**	**209,402**	**11.63**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2023

(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)
52. POLK #4 CT (GAS) TOTAL [4]	**180**	**1,150**	**0.9**	**-**	**91.3**	**10,513**	**GAS**	**11,760**	**1,028,061**	**12,090.0**	**106,527**	**9.26**	**9.06**
53. POLK #5 CT (GAS) TOTAL [4]	**180**	**1,050**	**0.8**	**-**	**72.9**	**11,457**	**GAS**	**11,700**	**1,028,205**	**12,030.0**	**105,983**	**10.09**	**9.06**
54. POLK #2 CC TOTAL	**1,200**	**172,350**	**19.3**	**81.7**	**81.2**	**7,224**	**-**	**-**	**-**	**1,245,010.0**	**11,030,523**	**6.40**	**-**
55. POLK STATION TOTAL	**1,445**	**180,930**	**16.9**	**83.8**	**80.5**	**7,307**	**-**	**-**	**-**	**1,322,040.0**	**11,709,268**	**6.47**	**-**
56. BAYSIDE #1	792	225,500	38.3	96.6	39.6	7,562	GAS	1,658,700	1,028,004	1,705,150.0	15,025,141	6.66	9.06
57. BAYSIDE #2	1,047	145,510	18.7	97.3	19.5	8,515	GAS	1,205,230	1,027,995	1,238,970.0	10,917,437	7.50	9.06
58. BAYSIDE #3	61	10	0.0	79.5	16.4	29,000	GAS	280	1,035,714	290.0	2,536	25.36	9.06
59. BAYSIDE #4	61	10	0.0	98.6	16.4	29,000	GAS	280	1,035,714	290.0	2,536	25.36	9.06
60. BAYSIDE #5	61	10	0.0	98.6	16.4	29,000	GAS	280	1,035,714	290.0	2,536	25.36	9.06
61. BAYSIDE #6	61	10	0.0	98.6	16.4	29,000	GAS	280	1,035,714	290.0	2,536	25.36	9.06
62. BAYSIDE STATION TOTAL	**2,083**	**371,050**	**24.0**	**96.6**	**28.2**	**7,938**	**GAS**	**2,865,050**	**1,028,003**	**2,945,280.0**	**25,952,722**	**6.99**	**9.06**
63. SYSTEM TOTAL	**6,733**	**1,523,050**	**30.4**	**67.7**	**77.8**	**6,345**	**-**	**-**	**-**	**9,664,230.0**	**80,591,341**	**5.29**	**-**

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. 20220001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 15 OF 42

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2023

(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	19.7	300	2.1	-	2.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	4,600	456.3	-	456.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	17,260	34.2	-	34.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	17,990	33.7	-	33.7	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	19,470	36.4	-	36.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.9	14,490	33.0	-	33.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	55.2	13,220	33.3	-	33.3	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	9,170	34.1	-	34.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.3	11,510	32.4	-	32.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	18,640	34.7	-	34.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	19,540	36.5	-	36.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	14,780	34.3	-	34.3	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	31.4	6,350.0	28.1	-	28.1	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	11,010.0	20.6	-	20.6	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	54.4	15,030.0	38.4	-	38.4	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	15,030.0	28.1	-	28.1	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	14.2	11,140.0	109.0	-	109.0	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	55.0	12,390.0	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	2,830.0	5.6	-	5.6	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	61.0	14,170.0	32.3	-	32.3	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR	25.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR	60.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL (3)	**1321.5**	**249,240**	**26.2**	**-**	**26.2**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL	**335**	**717,980**	**297.7**	**0.0**	**305.3**	**6,244**	**GAS**	**4,361,200**	**1,028,001**	**4,483,320.0**	**31,584,064**	**4.40**	**7.24**
28. BIG BEND #2 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
30. B.B.#3 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL	**345**	**0**	**0.0**	**82.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
32. B.B.#4 (GAS)	422	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
33. B.B.#4 (COAL)	410	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
34. BIG BEND #4 TOTAL	**410**	**0**	**0.0**	**65.5**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
35. B.B. IGNITION	-	-	-	-	-	-	GAS	0	0	0.0	0	-	0.00
36. B.B.C.T.#4 TOTAL	**56**	**130**	**0.3**	**78.6**	**77.4**	**13,077**	**GAS**	**1,650**	**1,030,303**	**1,700.0**	**11,949**	**9.19**	**7.24**
37. B.B.C.T.#5 TOTAL	**330**	**0**	**0.0**	**95.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL	**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL	**1,806**	**718,110**	**55.2**	**68.1**	**305.1**	**6,246**	**-**	**-**	**-**	**4,485,020.0**	**31,596,013**	**4.40**	**-**
40. POLK #1 GASIFIER	245	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)	220	5,310	3.4	-	75.4	8,913	GAS	46,050	1,027,796	47,330.0	333,497	6.28	7.24
42. POLK #1 TOTAL	**245**	**5,310**	**3.0**	**93.8**	**75.4**	**8,913**	**-**	**-**	**-**	**47,330.0**	**333,497**	**6.28**	**-**
43. POLK #2 ST DUCT FIRING	120	450	0.5	-	53.6	8,267	GAS	3,620	1,027,624	3,720.0	26,216	5.83	7.24
44. POLK #2 ST W/O DUCT FIRING	360	314,780	-	-	-	-		2,159,685	1,028,006	2,220,170.0	15,640,564	4.97	7.24
45. POLK #2 ST TOTAL	**480**	**315,230**	**91.2**	**-**	**93.8**	**7,055**	**GAS**	**-**	**-**	**2,223,890.0**	**15,666,780**	**4.97**	**-**
46. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
47. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	47,330	31.55	142.13
48. POLK #2 TOTAL (4)	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,330**	**31.55**	**-**
49. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
50. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	47,187	31.46	142.13
51. POLK #3 TOTAL (4)	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,187**	**31.46**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2023

(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)
52. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
53. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
54. POLK #2 CC TOTAL	**1,080**	**315,530**	**40.6**	**97.4**	**93.8**	**7,060**	**-**	**-**	**-**	**2,227,790.0**	**15,761,297**	**5.00**	**-**
55. POLK STATION TOTAL	**1,325**	**320,840**	**33.6**	**96.8**	**93.0**	**7,091**	**-**	**-**	**-**	**2,275,120.0**	**16,094,794**	**5.02**	**-**
56. BAYSIDE #1	720	184,300	35.6	96.6	36.8	7,817	GAS	1,401,460	1,027,999	1,440,700.0	10,149,455	5.51	7.24
57. BAYSIDE #2	954	119,810	17.4	51.9	18.2	9,015	GAS	1,050,640	1,028,002	1,080,060.0	7,608,796	6.35	7.24
58. BAYSIDE #3	56	110	0.3	98.6	98.2	11,909	GAS	1,270	1,031,496	1,310.0	9,197	8.36	7.24
59. BAYSIDE #4	56	110	0.3	78.9	98.2	11,455	GAS	1,220	1,032,787	1,260.0	8,835	8.03	7.24
60. BAYSIDE #5	56	10	0.0	78.9	17.9	31,000	GAS	300	1,033,333	310.0	2,173	21.73	7.24
61. BAYSIDE #6	56	110	0.3	78.9	98.2	11,909	GAS	1,270	1,031,496	1,310.0	9,197	8.36	7.24
62. BAYSIDE STATION TOTAL	**1,898**	**304,450**	**22.3**	**72.6**	**26.2**	**8,293**	**GAS**	**2,456,160**	**1,028,007**	**2,524,950.0**	**17,787,653**	**5.84**	**7.24**
63. SYSTEM TOTAL	**6,351**	**1,592,640**	**34.8**	**61.2**	**96.3**	**5,830**	**-**	**-**	**-**	**9,285,090.0**	**65,478,460**	**4.11**	**-**

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2023

(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	19.7	320	2.2	-	2.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	4,970	477.2	-	477.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	19,380	37.2	-	37.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	20,170	36.5	-	36.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	20,280	36.7	-	36.7	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.9	16,220	35.8	-	35.8	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	55.2	14,790	36.0	-	36.0	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	9,990	35.9	-	35.9	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.3	12,870	35.1	-	35.1	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	20,110	36.2	-	36.2	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	20,350	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	16,810	37.8	-	37.8	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	31.4	7,130.0	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	12,350.0	22.3	-	22.3	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	54.4	16,850.0	41.6	-	41.6	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	16,850.0	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	14.2	12,490.0	118.2	-	118.2	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	55.0	13,900.0	34.0	-	34.0	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	3,180.0	6.1	-	6.1	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	61.0	15,900.0	35.0	-	35.0	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR	25.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR	60.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL [3]	**1321.5**	**275,250**	**28.0**	**-**	**28.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL	**335**	**761,470**	**305.5**	**0.0**	**313.1**	**6,239**	**GAS**	**4,621,480**	**1,028,002**	**4,750,890.0**	**32,276,469**	**4.24**	**6.98**
28. BIG BEND #2 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
30. B.B.#3 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL	**345**	**0**	**0.0**	**82.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
32. B.B.#4 (GAS)	422	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
33. B.B.#4 (COAL)	410	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
34. BIG BEND #4 TOTAL	**410**	**0**	**0.0**	**89.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
35. B.B. IGNITION	-	-	-	-	-	-	GAS	0	0	0.0	0	-	0.00
36. B.B.C.T.#4 TOTAL	**56**	**330**	**0.8**	**98.3**	**73.7**	**12,394**	**GAS**	**3,990**	**1,025,063**	**4,090.0**	**27,866**	**8.44**	**6.98**
37. B.B.C.T.#5 TOTAL	**330**	**0**	**0.0**	**96.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL	**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL	**1,806**	**761,800**	**56.7**	**74.3**	**312.7**	**6,242**	**-**	**-**	**-**	**4,754,980.0**	**32,304,335**	**4.24**	**-**
40. POLK #1 GASIFIER	245	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)	220	10,230	6.3	-	77.5	8,867	GAS	88,240	1,027,992	90,710.0	616,269	6.02	6.98
42. POLK #1 TOTAL	**245**	**10,230**	**5.6**	**72.6**	**77.5**	**8,867**	**-**	**-**	**-**	**90,710.0**	**616,269**	**6.02**	**-**
43. POLK #2 ST DUCT FIRING	120	2,080	2.3	-	57.8	8,284	GAS	16,760	1,028,043	17,230.0	117,052	5.63	6.98
44. POLK #2 ST W/O DUCT FIRING	360	421,180	-	-	-	-		2,861,285	1,028,003	2,941,410.0	19,983,247	4.74	6.98
45. POLK #2 ST TOTAL	**480**	**423,260**	**118.5**	**-**	**115.7**	**6,990**	**GAS**	**-**	**-**	**2,958,640.0**	**20,100,299**	**4.75**	**-**
46. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
47. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	47,351	31.57	142.20
48. POLK #2 TOTAL [4]	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,351**	**31.57**	**-**
49. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
50. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	47,210	31.47	142.20
51. POLK #3 TOTAL [4]	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,210**	**31.47**	**-**

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DOCKET NO. 20220001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 18 OF 42

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2023

(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)
52. POLK #4 CT (GAS) TOTAL	[4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
53. POLK #5 CT (GAS) TOTAL	[4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
54. POLK #2 CC TOTAL		**1,080**	**423,560**	**52.7**	**97.4**	**115.7**	**6,994**	**-**	**-**	**-**	**2,962,540.0**	**20,194,860**	**4.77**	**-**
55. POLK STATION TOTAL		**1,325**	**433,790**	**44.0**	**92.8**	**112.9**	**7,039**	**-**	**-**	**-**	**3,053,250.0**	**20,811,129**	**4.80**	**-**
56. BAYSIDE #1		720	248,930	46.5	96.6	48.1	7,602	GAS	1,840,890	1,028,003	1,892,440.0	12,856,797	5.16	6.98
57. BAYSIDE #2		954	159,810	22.5	97.3	23.5	8,530	GAS	1,326,020	1,027,994	1,363,140.0	9,260,939	5.79	6.98
58. BAYSIDE #3		56	300	0.7	98.6	76.5	12,467	GAS	3,640	1,027,473	3,740.0	25,422	8.47	6.98
59. BAYSIDE #4		56	220	0.5	98.6	78.6	12,909	GAS	2,750	1,032,727	2,840.0	19,206	8.73	6.98
60. BAYSIDE #5		56	460	1.1	98.6	74.7	12,304	GAS	5,500	1,029,091	5,660.0	38,412	8.35	6.98
61. BAYSIDE #6		56	420	1.0	79.5	68.2	12,690	GAS	5,180	1,028,958	5,330.0	36,177	8.61	6.98
62. BAYSIDE STATION TOTAL		**1,898**	**410,140**	**29.0**	**96.6**	**34.2**	**7,981**	**GAS**	**3,183,980**	**1,028,006**	**3,273,150.0**	**22,236,953**	**5.42**	**6.98**
63. SYSTEM TOTAL		**6,351**	**1,880,980**	**39.8**	**69.4**	**108.9**	**5,891**	**-**	**-**	**-**	**11,081,380.0**	**75,352,417**	**4.01**	**-**

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. 20220001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 19 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2023

(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	19.7	290	2.0	-	2.0	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	4,400	436.5	-	436.5	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,730	33.1	-	33.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	17,360	32.5	-	32.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,370	32.5	-	32.5	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.9	13,970	31.9	-	31.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	55.2	12,750	32.1	-	32.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,650	32.1	-	32.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.3	11,070	31.2	-	31.2	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,510	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,440	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	14,810	34.4	-	34.4	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	31.4	6,110.0	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	10,590.0	19.8	-	19.8	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	54.4	14,450.0	36.9	-	36.9	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	14,450.0	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	14.2	10,710.0	104.8	-	104.8	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	55.0	11,910.0	30.1	-	30.1	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	2,720.0	5.4	-	5.4	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	61.0	13,630.0	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR	25.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR	60.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL [(3)]	**1321.5**	**236,210**	**24.8**	**-**	**24.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL	**335**	**740,710**	**307.1**	**0.0**	**314.5**	**6,238**	**GAS**	**4,494,360**	**1,028,002**	**4,620,210.0**	**31,049,829**	**4.19**	**6.91**
28. BIG BEND #2 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
30. B.B.#3 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL	**345**	**0**	**0.0**	**82.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
32. B.B.#4 (GAS)	422	10,880	3.6	-	-	-	GAS	121,630	1,027,954	125,030.0	840,296	7.72	6.91
33. B.B.#4 (COAL)	410	61,670	20.9	-	-	-	COAL	31,490	22,499,524	708,510.0	2,688,592	4.36	85.38
34. BIG BEND #4 TOTAL	**410**	**72,550**	**24.6**	**89.3**	**60.6**	**11,489**		**-**	**-**	**833,540.0**	**3,528,888**	**4.86**	**-**
35. B.B. IGNITION	-	-	-	-	-	-	GAS	12,100	1,028,926	12,450.0	83,594	-	6.91
36. B.B.C.T.#4 TOTAL	**56**	**180**	**0.4**	**98.3**	**64.3**	**12,556**	**GAS**	**2,200**	**1,027,273**	**2,260.0**	**15,199**	**8.44**	**6.91**
37. B.B.C.T.#5 TOTAL	**330**	**0**	**0.0**	**96.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL	**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL	**1,806**	**813,440**	**62.6**	**74.3**	**178.3**	**6,707**	**-**	**-**	**-**	**5,456,010.0**	**34,677,510**	**4.26**	**-**
40. POLK #1 GASIFIER	245	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)	220	11,260	7.1	-	77.5	8,897	GAS	97,460	1,027,909	100,180.0	673,314	5.98	6.91
42. POLK #1 TOTAL	**245**	**11,260**	**6.4**	**93.8**	**77.5**	**8,897**	**-**	**-**	**-**	**100,180.0**	**673,314**	**5.98**	**-**
43. POLK #2 ST DUCT FIRING	120	1,980	2.3	-	55.0	8,273	GAS	15,930	1,028,249	16,380.0	110,054	5.56	6.91
44. POLK #2 ST W/O DUCT FIRING	360	461,700	-	-	-	-		3,115,455	1,028,004	3,202,700.0	21,523,497	4.66	6.91
45. POLK #2 ST TOTAL	**480**	**463,680**	**134.2**	**-**	**134.0**	**6,942**	**GAS**	**-**	**-**	**3,219,080.0**	**21,633,551**	**4.67**	**-**
46. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	1	0.00	0.00
47. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	47,373	31.58	142.26
48. POLK #2 TOTAL [(4)]	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,374**	**31.58**	**-**
49. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
50. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	47,231	31.49	142.26
51. POLK #3 TOTAL [(4)]	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,231**	**31.49**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2023

(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)
52. POLK #4 CT (GAS) TOTAL	[4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
53. POLK #5 CT (GAS) TOTAL	[4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
54. POLK #2 CC TOTAL		**1,080**	**463,980**	**59.7**	**97.4**	**133.9**	**6,946**	**-**	**-**	**-**	**3,222,980.0**	**21,728,156**	**4.68**	**-**
55. POLK STATION TOTAL		**1,325**	**475,240**	**49.8**	**96.8**	**129.2**	**6,993**	**-**	**-**	**-**	**3,323,160.0**	**22,401,470**	**4.71**	**-**
56. BAYSIDE #1		720	278,710	53.8	96.6	55.6	7,513	GAS	2,036,880	1,027,999	2,093,910.0	14,072,032	5.05	6.91
57. BAYSIDE #2		954	194,280	28.3	97.3	29.5	8,191	GAS	1,548,040	1,028,003	1,591,390.0	10,694,821	5.50	6.91
58. BAYSIDE #3		56	190	0.5	98.6	56.5	13,579	GAS	2,500	1,032,000	2,580.0	17,272	9.09	6.91
59. BAYSIDE #4		56	100	0.2	98.6	44.6	15,600	GAS	1,520	1,026,316	1,560.0	10,501	10.50	6.91
60. BAYSIDE #5		56	110	0.3	98.6	65.5	13,091	GAS	1,410	1,021,277	1,440.0	9,741	8.86	6.91
61. BAYSIDE #6		56	260	0.6	98.6	66.3	12,615	GAS	3,190	1,028,213	3,280.0	22,039	8.48	6.91
62. BAYSIDE STATION TOTAL		**1,898**	**473,650**	**34.7**	**97.2**	**40.8**	**7,799**	**GAS**	**3,593,540**	**1,028,000**	**3,694,160.0**	**24,826,406**	**5.24**	**6.91**
63. SYSTEM TOTAL		**6,351**	**1,998,540**	**43.7**	**70.3**	**105.9**	**6,241**	**-**	**-**	**-**	**12,473,330.0**	**81,905,386**	**4.10**	**-**

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. 20220001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 21 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2023

(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	19.7	290	2.0	-	2.0	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	4,260	409.0	-	409.0	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,210	31.1	-	31.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,820	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,170	31.1	-	31.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.9	13,530	29.9	-	29.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	55.2	12,360	30.1	-	30.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,420	30.3	-	30.3	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.3	10,720	29.2	-	29.2	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,260	29.3	-	29.3	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,230	31.2	-	31.2	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	14,210	31.9	-	31.9	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	31.4	5,920.0	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	10,260.0	18.6	-	18.6	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	54.4	14,000.0	34.6	-	34.6	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	14,000.0	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	14.2	10,370.0	98.2	-	98.2	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	55.0	11,540.0	28.2	-	28.2	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	2,640.0	5.1	-	5.1	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	61.0	13,200.0	29.1	-	29.1	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR	25.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR	60.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL	(3) **1321.5**	**229,700**	**23.4**	**-**	**23.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL	**335**	**765,360**	**307.1**	**0.0**	**314.7**	**6,237**	**GAS**	**4,643,780**	**1,028,001**	**4,773,810.0**	**32,261,378**	**4.22**	**6.95**
28. BIG BEND #2 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
30. B.B.#3 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL	**345**	**0**	**0.0**	**82.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
32. B.B.#4 (GAS)	422	12,200	3.9	-	-	-	GAS	135,510	1,027,968	139,300.0	941,418	7.72	6.95
33. B.B.#4 (COAL)	410	69,140	22.7	-	-	-	COAL	35,080	22,502,566	789,390.0	3,034,523	4.39	86.50
34. BIG BEND #4 TOTAL	**410**	**81,340**	**26.7**	**89.3**	**62.2**	**11,417**		**-**	**-**	**928,690.0**	**3,975,941**	**4.89**	**-**
35. B.B. IGNITION	-	-	-	-	-	-	GAS	7,090	1,028,209	7,290.0	49,256	-	6.95
36. B.B.C.T.#4 TOTAL	**56**	**350**	**0.8**	**98.3**	**78.1**	**12,171**	**GAS**	**4,140**	**1,028,986**	**4,260.0**	**28,762**	**8.22**	**6.95**
37. B.B.C.T.#5 TOTAL	**330**	**0**	**0.0**	**96.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL	**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL	**1,806**	**847,050**	**63.0**	**74.3**	**174.8**	**6,737**	**-**	**-**	**-**	**5,706,760.0**	**36,315,337**	**4.29**	**-**
40. POLK #1 GASIFIER	245	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)	220	15,280	9.3	-	77.2	8,923	GAS	132,630	1,028,048	136,350.0	921,410	6.03	6.95
42. POLK #1 TOTAL	**245**	**15,280**	**8.4**	**93.8**	**77.2**	**8,923**	**-**	**-**	**-**	**136,350.0**	**921,410**	**6.03**	**-**
43. POLK #2 ST DUCT FIRING	120	2,110	2.4	-	58.6	8,303	GAS	17,040	1,028,169	17,520.0	118,381	5.61	6.95
44. POLK #2 ST W/O DUCT FIRING	360	501,510	-	-	-	-		3,382,195	1,028,004	3,476,910.0	23,496,866	4.69	6.95
45. POLK #2 ST TOTAL	**480**	**503,620**	**141.0**	**-**	**137.9**	**6,939**	**GAS**	**-**	**-**	**3,494,430.0**	**23,615,247**	**4.69**	**-**
46. POLK #2 CT (GAS)	150	500	0.4	-	83.3	11,420	GAS	5,550	1,028,829	5,710.0	38,557	7.71	6.95
47. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	47,394	31.60	142.32
48. POLK #2 TOTAL	(4) **150**	**650**	**0.6**	**-**	**85.6**	**11,785**	**-**	**-**	**-**	**7,660.0**	**85,951**	**13.22**	**-**
49. POLK #3 CT (GAS)	150	500	0.4	-	83.3	11,480	GAS	5,590	1,026,834	5,740.0	38,835	7.77	6.95
50. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	47,252	31.50	142.33
51. POLK #3 TOTAL	(4) **150**	**650**	**0.6**	**-**	**85.6**	**11,831**	**-**	**-**	**-**	**7,690.0**	**86,087**	**13.24**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2023

(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)
52. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
53. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
54. POLK #2 CC TOTAL	**1,080**	**504,920**	**62.8**	**97.4**	**137.2**	**6,951**	**-**	**-**	**-**	**3,509,780.0**	**23,787,285**	**4.71**	**-**
55. POLK STATION TOTAL	**1,325**	**520,200**	**52.8**	**96.8**	**130.9**	**7,009**	**-**	**-**	**-**	**3,646,130.0**	**24,708,695**	**4.75**	**-**
56. BAYSIDE #1	720	297,600	55.6	96.6	57.5	7,491	GAS	2,168,750	1,027,998	2,229,470.0	15,066,792	5.06	6.95
57. BAYSIDE #2	954	199,250	28.1	97.3	29.3	8,207	GAS	1,590,790	1,027,992	1,635,320.0	11,051,573	5.55	6.95
58. BAYSIDE #3	56	510	1.2	98.6	70.1	12,725	GAS	6,310	1,028,526	6,490.0	43,837	8.60	6.95
59. BAYSIDE #4	56	400	1.0	98.6	71.4	12,825	GAS	4,990	1,028,056	5,130.0	34,667	8.67	6.95
60. BAYSIDE #5	56	480	1.2	98.6	71.4	12,708	GAS	5,940	1,026,936	6,100.0	41,267	8.60	6.95
61. BAYSIDE #6	56	600	1.4	98.6	63.0	13,250	GAS	7,730	1,028,461	7,950.0	53,702	8.95	6.95
62. BAYSIDE STATION TOTAL	**1,898**	**498,840**	**35.3**	**97.2**	**41.5**	**7,799**	**GAS**	**3,784,510**	**1,027,996**	**3,890,460.0**	**26,291,838**	**5.27**	**6.95**
63. SYSTEM TOTAL	**6,351**	**2,095,790**	**44.4**	**70.3**	**106.0**	**6,319**	**-**	**-**	**-**	**13,243,350.0**	**87,315,870**	**4.17**	**-**

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

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2023

(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		19.7	270	1.8	-	1.8	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR		1.4	4,170	400.3	-	400.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR		70.1	15,640	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR		74.2	16,210	29.4	-	29.4	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR		74.3	16,580	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR		60.9	13,060	28.8	-	28.8	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR		55.2	11,940	29.1	-	29.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR		37.4	8,290	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR		49.3	10,340	28.2	-	28.2	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR		74.7	15,770	28.4	-	28.4	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR		74.3	16,660	30.1	-	30.1	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR		59.8	13,780	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR		31.4	5,710.0	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR		74.3	9,900.0	17.9	-	17.9	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR		54.4	13,500.0	33.4	-	33.4	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR		74.3	13,500.0	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR		14.2	10,000.0	94.7	-	94.7	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR		55.0	11,130.0	27.2	-	27.2	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR		70.0	2,540.0	4.9	-	4.9	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR		61.0	12,730.0	28.0	-	28.0	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR		25.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR		60.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR		74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR		74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL	(3)	**1321.5**	**222,010**	**22.6**	**-**	**22.6**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL		**335**	**765,270**	**307.0**	**0.0**	**314.7**	**6,237**	**GAS**	**4,643,250**	**1,028,004**	**4,773,280.0**	**32,216,291**	**4.21**	**6.94**
28. BIG BEND #2 TOTAL		**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)		345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
30. B.B.#3 (COAL)		0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL		**345**	**0**	**0.0**	**82.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
32. B.B.#4 (GAS)		422	15,340	4.9	-	-	-	GAS	171,000	1,027,953	175,780.0	1,186,450	7.73	6.94
33. B.B.#4 (COAL)		410	86,950	28.5	-	-	-	COAL	44,270	22,501,016	996,120.0	3,900,479	4.49	88.11
34. BIG BEND #4 TOTAL		**410**	**102,290**	**33.5**	**89.3**	**61.3**	**11,457**		**-**	**-**	**1,171,900.0**	**5,086,929**	**4.97**	**-**
35. B.B. IGNITION		-	-	-	-	-	-	GAS	12,110	1,027,250	12,440.0	84,023	-	6.94
36. B.B.C.T.#4 TOTAL		**56**	**640**	**1.5**	**98.3**	**81.6**	**11,813**	**GAS**	**7,350**	**1,028,571**	**7,560.0**	**50,997**	**7.97**	**6.94**
37. B.B.C.T.#5 TOTAL		**330**	**0**	**0.0**	**96.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL		**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL		**1,806**	**868,200**	**64.6**	**74.3**	**157.5**	**6,856**	**-**	**-**	**-**	**5,952,740.0**	**37,438,240**	**4.31**	**-**
40. POLK #1 GASIFIER		245	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)		220	17,290	10.6	-	77.0	8,894	GAS	149,590	1,027,943	153,770.0	1,037,901	6.00	6.94
42. POLK #1 TOTAL		**245**	**17,290**	**9.5**	**93.8**	**77.0**	**8,894**	**-**	**-**	**-**	**153,770.0**	**1,037,901**	**6.00**	**-**
43. POLK #2 ST DUCT FIRING		120	2,360	2.6	-	61.5	8,254	GAS	18,950	1,027,968	19,480.0	131,481	5.57	6.94
44. POLK #2 ST W/O DUCT FIRING		360	518,620	-	-	-	-		3,492,715	1,028,005	3,590,530.0	24,233,527	4.67	6.94
45. POLK #2 ST TOTAL		**480**	**520,980**	**145.9**	**-**	**142.8**	**6,929**	**GAS**	**-**	**-**	**3,610,010.0**	**24,365,008**	**4.68**	**-**
46. POLK #2 CT (GAS)		150	90	0.1	-	60.0	13,667	GAS	1,200	1,025,000	1,230.0	8,326	9.25	6.94
47. POLK #2 CT (OIL)		159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	47,409	31.61	142.37
48. POLK #2 TOTAL	(4)	**150**	**240**	**0.2**	**-**	**77.7**	**13,250**	**-**	**-**	**-**	**3,180.0**	**55,735**	**23.22**	**-**
49. POLK #3 CT (GAS)		150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
50. POLK #3 CT (OIL)		159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	47,267	31.51	142.37
51. POLK #3 TOTAL	(4)	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,267**	**31.51**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2023

(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)
52. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
53. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
54. POLK #2 CC TOTAL	**1,080**	**521,370**	**64.9**	**97.4**	**142.6**	**6,934**	**-**	**-**	**-**	**3,615,140.0**	**24,468,010**	**4.69**	**-**
55. POLK STATION TOTAL	**1,325**	**538,660**	**54.6**	**96.8**	**134.9**	**6,997**	**-**	**-**	**-**	**3,768,910.0**	**25,505,911**	**4.74**	**-**
56. BAYSIDE #1	720	308,440	57.6	96.6	59.6	7,475	GAS	2,242,670	1,028,002	2,305,470.0	15,560,331	5.04	6.94
57. BAYSIDE #2	954	198,000	27.9	97.3	29.1	8,212	GAS	1,581,740	1,028,001	1,626,030.0	10,974,597	5.54	6.94
58. BAYSIDE #3	56	760	1.8	98.6	71.4	12,618	GAS	9,330	1,027,867	9,590.0	64,734	8.52	6.94
59. BAYSIDE #4	56	550	1.3	98.6	81.8	12,127	GAS	6,490	1,027,735	6,670.0	45,030	8.19	6.94
60. BAYSIDE #5	56	790	1.9	98.6	78.4	12,241	GAS	9,420	1,026,539	9,670.0	65,359	8.27	6.94
61. BAYSIDE #6	56	730	1.8	98.6	76.7	12,479	GAS	8,860	1,028,217	9,110.0	61,473	8.42	6.94
62. BAYSIDE STATION TOTAL	**1,898**	**509,270**	**36.1**	**97.2**	**42.3**	**7,789**	**GAS**	**3,858,510**	**1,027,998**	**3,966,540.0**	**26,771,524**	**5.26**	**6.94**
63. SYSTEM TOTAL	**6,351**	**2,138,140**	**45.3**	**70.3**	**104.5**	**6,402**	**-**	**-**	**-**	**13,688,190.0**	**89,715,675**	**4.20**	**-**

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2023

(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	19.7	230	1.6	-	1.6	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	3,460	343.3	-	343.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,590	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,080	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,270	26.7	-	26.7	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.9	11,340	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	55.2	10,380	26.1	-	26.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,690	24.8	-	24.8	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.3	8,990	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	13,620	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,310	26.7	-	26.7	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	12,020	27.9	-	27.9	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	31.4	4,960.0	21.9	-	21.9	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	8,600.0	16.1	-	16.1	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	54.4	11,730.0	29.9	-	29.9	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	11,730.0	21.9	-	21.9	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	14.2	8,690.0	85.0	-	85.0	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	55.0	9,670.0	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	2,210.0	4.4	-	4.4	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	61.0	11,060.0	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR	25.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR	60.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL	(3) **1321.5**	**191,890**	**20.2**	**-**	**20.2**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL	**335**	**740,680**	**307.1**	**0.0**	**314.5**	**6,238**	**GAS**	**4,494,220**	**1,028,000**	**4,620,060.0**	**31,409,560**	**4.24**	**6.99**
28. BIG BEND #2 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
30. B.B.#3 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL	**345**	**0**	**0.0**	**82.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
32. B.B.#4 (GAS)	422	23,640	7.8	-	-	-	GAS	256,430	1,028,000	263,610.0	1,792,159	7.58	6.99
33. B.B.#4 (COAL)	410	133,980	45.4	-	-	-	COAL	66,390	22,500,226	1,493,790.0	5,857,911	4.37	88.23
34. BIG BEND #4 TOTAL	**410**	**157,620**	**53.4**	**89.3**	**68.9**	**11,150**		**-**	**-**	**1,757,400.0**	**7,650,070**	**4.85**	**-**
35. B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	1,027,944	5,150.0	35,014	-	6.99
36. B.B.C.T.#4 TOTAL	**56**	**2,580**	**6.4**	**98.3**	**78.1**	**11,961**	**GAS**	**30,020**	**1,027,981**	**30,860.0**	**209,806**	**8.13**	**6.99**
37. B.B.C.T.#5 TOTAL	**330**	**0**	**0.0**	**96.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL	**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL	**1,806**	**900,880**	**69.3**	**74.3**	**136.5**	**7,113**	**-**	**-**	**-**	**6,408,320.0**	**39,304,450**	**4.36**	**-**
40. POLK #1 GASIFIER	245	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)	220	54,160	34.2	-	79.2	8,824	GAS	464,890	1,028,007	477,910.0	3,249,060	6.00	6.99
42. POLK #1 TOTAL	**245**	**54,160**	**30.7**	**93.8**	**79.2**	**8,824**	**-**	**-**	**-**	**477,910.0**	**3,249,060**	**6.00**	**-**
43. POLK #2 ST DUCT FIRING	120	10,970	12.7	-	63.5	8,273	GAS	88,280	1,027,979	90,750.0	616,978	5.62	6.99
44. POLK #2 ST W/O DUCT FIRING	360	466,290	-	-	-	-		3,149,055	1,028,004	3,237,240.0	22,008,365	4.72	6.99
45. POLK #2 ST TOTAL	**480**	**477,260**	**138.1**	**-**	**116.8**	**6,973**	**GAS**	**-**	**-**	**3,327,990.0**	**22,625,343**	**4.74**	**-**
46. POLK #2 CT (GAS)	150	190	0.2	-	63.3	12,737	GAS	2,360	1,025,424	2,420.0	16,494	8.68	6.99
47. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	47,417	31.61	142.39
48. POLK #2 TOTAL	(4) **150**	**340**	**0.3**	**-**	**74.1**	**12,853**	**-**	**-**	**-**	**4,370.0**	**63,911**	**18.80**	**-**
49. POLK #3 CT (GAS)	150	100	0.1	-	66.7	12,800	GAS	1,240	1,032,258	1,280.0	8,666	8.67	6.99
50. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	47,274	31.52	142.39
51. POLK #3 TOTAL	(4) **150**	**250**	**0.2**	**-**	**80.9**	**12,920**	**-**	**-**	**-**	**3,230.0**	**55,940**	**22.38**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2023

(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)
52. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
53. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
54. POLK #2 CC TOTAL	**1,080**	**477,850**	**61.5**	**97.4**	**116.6**	**6,980**	**-**	**-**	**-**	**3,335,590.0**	**22,745,194**	**4.76**	**-**
55. POLK STATION TOTAL	**1,325**	**532,010**	**55.8**	**96.8**	**106.6**	**7,168**	**-**	**-**	**-**	**3,813,500.0**	**25,994,254**	**4.89**	**-**
56. BAYSIDE #1	720	287,400	55.4	29.0	57.4	7,505	GAS	2,098,230	1,028,000	2,156,980.0	14,664,276	5.10	6.99
57. BAYSIDE #2	954	34,260	5.0	97.3	22.2	8,632	GAS	287,660	1,028,019	295,720.0	2,010,421	5.87	6.99
58. BAYSIDE #3	56	2,640	6.5	98.6	78.6	12,064	GAS	30,990	1,027,751	31,850.0	216,585	8.20	6.99
59. BAYSIDE #4	56	2,230	5.5	98.6	79.6	12,022	GAS	26,080	1,027,991	26,810.0	182,270	8.17	6.99
60. BAYSIDE #5	56	3,340	8.3	98.6	75.5	12,234	GAS	39,760	1,027,666	40,860.0	277,878	8.32	6.99
61. BAYSIDE #6	56	3,190	7.9	98.6	74.0	12,370	GAS	38,390	1,027,872	39,460.0	268,303	8.41	6.99
62. BAYSIDE STATION TOTAL	**1,898**	**333,060**	**24.4**	**71.5**	**49.7**	**7,781**	**GAS**	**2,521,110**	**1,027,992**	**2,591,680.0**	**17,619,733**	**5.29**	**6.99**
63. SYSTEM TOTAL	**6,351**	**1,957,840**	**42.8**	**62.7**	**116.6**	**6,545**	**-**	**-**	**-**	**12,813,500.0**	**82,918,437**	**4.24**	**-**

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2023

(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	19.7	220	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	3,580	343.7	-	343.7	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,430	25.8	-	25.8	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	13,930	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	13,920	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.9	11,200	24.7	-	24.7	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	55.2	10,250	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	7,070	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.3	8,890	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	14,150	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	13,980	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,950	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	31.4	4,920.0	21.1	-	21.1	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	8,530.0	15.4	-	15.4	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	54.4	11,640.0	28.8	-	28.8	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	11,640.0	21.1	-	21.1	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	14.2	8,620.0	81.6	-	81.6	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	55.0	9,590.0	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	2,190.0	4.2	-	4.2	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	61.0	10,970.0	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR	25.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR	60.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL (3)	**1321.5**	**190,960**	**19.4**	**-**	**19.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL	**335**	**762,590**	**306.0**	**0.0**	**313.6**	**6,239**	**GAS**	**4,627,950**	**1,028,002**	**4,757,540.0**	**32,803,846**	**4.30**	**7.09**
28. BIG BEND #2 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
30. B.B.#3 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL	**345**	**0**	**0.0**	**82.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
32. B.B.#4 (GAS)	422	27,240	8.7	-	-	-	GAS	297,930	1,027,993	306,270.0	2,111,788	7.75	7.09
33. B.B.#4 (COAL)	410	154,380	50.6	-	-	-	COAL	77,130	22,501,361	1,735,530.0	6,864,534	4.45	89.00
34. BIG BEND #4 TOTAL	**410**	**181,620**	**59.5**	**8.6**	**66.5**	**11,242**		**-**	**-**	**2,041,800.0**	**8,976,322**	**4.94**	**-**
35. B.B. IGNITION	-	-	-	-	-	-	GAS	2,090	1,028,708	2,150.0	14,814	-	7.09
36. B.B.C.T.#4 TOTAL	**56**	**1,940**	**4.7**	**98.3**	**82.5**	**12,010**	**GAS**	**22,660**	**1,028,244**	**23,300.0**	**160,619**	**8.28**	**7.09**
37. B.B.C.T.#5 TOTAL	**330**	**0**	**0.0**	**96.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL	**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL	**1,806**	**946,150**	**70.4**	**55.9**	**126.4**	**7,211**	**-**	**-**	**-**	**6,822,640.0**	**41,955,601**	**4.43**	**-**
40. POLK #1 GASIFIER	245	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)	220	30,250	18.5	-	79.5	8,842	GAS	260,180	1,027,981	267,460.0	1,844,208	6.10	7.09
42. POLK #1 TOTAL	**245**	**30,250**	**16.6**	**93.8**	**79.5**	**8,842**	**-**	**-**	**-**	**267,460.0**	**1,844,208**	**6.10**	**-**
43. POLK #2 ST DUCT FIRING	120	9,150	10.2	-	61.5	8,272	GAS	73,630	1,027,978	75,690.0	521,904	5.70	7.09
44. POLK #2 ST W/O DUCT FIRING	360	416,180	-	-	-	-		2,824,165	1,028,007	2,903,260.0	20,018,252	4.81	7.09
45. POLK #2 ST TOTAL	**480**	**425,330**	**119.1**	**-**	**104.0**	**7,004**	**GAS**	**-**	**-**	**2,978,950.0**	**20,540,156**	**4.83**	**-**
46. POLK #2 CT (GAS)	150	360	0.3	-	60.0	12,861	GAS	4,510	1,026,608	4,630.0	31,969	8.88	7.09
47. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	47,418	31.61	142.40
48. POLK #2 TOTAL (4)	**150**	**510**	**0.5**	**-**	**67.2**	**12,902**	**-**	**-**	**-**	**6,580.0**	**79,387**	**15.57**	**-**
49. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
50. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	47,275	31.52	142.39
51. POLK #3 TOTAL (4)	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,275**	**31.52**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2023

(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)
52. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
53. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
54. POLK #2 CC TOTAL	**1,080**	**425,990**	**53.0**	**97.4**	**103.8**	**7,013**	**-**	**-**	**-**	**2,987,480.0**	**20,666,818**	**4.85**	**-**
55. POLK STATION TOTAL	**1,325**	**456,240**	**46.3**	**96.8**	**99.7**	**7,134**	**-**	**-**	**-**	**3,254,940.0**	**22,511,026**	**4.93**	**-**
56. BAYSIDE #1	720	247,770	46.3	0.0	47.9	7,617	GAS	1,835,790	1,027,999	1,887,190.0	13,012,451	5.25	7.09
57. BAYSIDE #2	954	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
58. BAYSIDE #3	56	1,260	3.0	98.6	83.3	12,048	GAS	14,780	1,027,064	15,180.0	104,764	8.31	7.09
59. BAYSIDE #4	56	1,050	2.5	98.6	89.3	11,781	GAS	12,030	1,028,263	12,370.0	85,271	8.12	7.09
60. BAYSIDE #5	56	1,560	3.7	98.6	79.6	12,205	GAS	18,530	1,027,523	19,040.0	131,344	8.42	7.09
61. BAYSIDE #6	56	2,380	5.7	98.6	80.2	12,055	GAS	27,920	1,027,579	28,690.0	197,903	8.32	7.09
62. BAYSIDE STATION TOTAL	**1,898**	**254,020**	**18.0**	**11.6**	**48.4**	**7,726**	**GAS**	**1,909,050**	**1,027,983**	**1,962,470.0**	**13,531,733**	**5.33**	**7.09**
63. SYSTEM TOTAL	**6,351**	**1,847,370**	**39.1**	**39.6**	**115.9**	**6,517**	**-**	**-**	**-**	**12,040,050.0**	**77,998,360**	**4.22**	**-**

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2023

(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	19.7	180	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	2,950	292.3	-	292.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	10,040	19.9	-	19.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,410	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	11,940	22.3	-	22.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.9	8,360	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	55.2	7,650	19.2	-	19.2	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,990	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.3	6,650	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,690	21.7	-	21.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	11,970	22.3	-	22.3	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,720	20.2	-	20.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	31.4	3,680.0	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	6,380.0	11.9	-	11.9	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	54.4	8,710.0	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	8,710.0	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	14.2	6,450.0	63.0	-	63.0	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	55.0	7,180.0	18.1	-	18.1	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	1,640.0	3.2	-	3.2	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	61.0	8,210.0	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR	25.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR	60.0	-	-	-	-	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR	74.5	-	-	-	-	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL	[3] **1321.5**	**147,780**	**15.5**	**-**	**15.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL	**335**	**724,890**	**300.1**	**0.0**	**307.8**	**6,244**	**GAS**	**4,403,120**	**1,028,003**	**4,526,420.0**	**31,137,337**	**4.30**	**7.07**
28. BIG BEND #2 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
30. B.B.#3 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL	**345**	**0**	**0.0**	**43.8**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
32. B.B.#4 (GAS)	422	9,690	3.2	-	-	-	GAS	108,330	1,027,970	111,360.0	766,072	7.91	7.07
33. B.B.#4 (COAL)	410	54,910	18.6	-	-	-	COAL	28,050	22,497,326	631,050.0	2,516,837	4.58	89.73
34. BIG BEND #4 TOTAL	**410**	**64,600**	**21.9**	**83.3**	**60.6**	**11,492**		**-**	**-**	**742,410.0**	**3,282,909**	**5.08**	**-**
35. B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	1,027,944	5,150.0	35,429	-	7.07
36. B.B.C.T.#4 TOTAL	**56**	**960**	**2.4**	**98.3**	**81.6**	**11,938**	**GAS**	**11,160**	**1,026,882**	**11,460.0**	**78,920**	**8.22**	**7.07**
37. B.B.C.T.#5 TOTAL	**330**	**0**	**0.0**	**96.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL	**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL	**1,806**	**790,450**	**60.7**	**65.6**	**182.6**	**6,680**	**-**	**-**	**-**	**5,280,290.0**	**34,534,595**	**4.37**	**-**
40. POLK #1 GASIFIER	245	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)	220	22,850	14.4	-	78.7	8,855	GAS	196,840	1,027,941	202,340.0	1,391,984	6.09	7.07
42. POLK #1 TOTAL	**245**	**22,850**	**12.9**	**93.8**	**78.7**	**8,855**	**-**	**-**	**-**	**202,340.0**	**1,391,984**	**6.09**	**-**
43. POLK #2 ST DUCT FIRING	120	5,550	6.4	-	63.4	8,270	GAS	44,650	1,027,996	45,900.0	315,749	5.69	7.07
44. POLK #2 ST W/O DUCT FIRING	360	298,780	-	-	-	-		2,057,365	1,028,004	2,114,980.0	14,548,972	4.87	7.07
45. POLK #2 ST TOTAL	**480**	**304,330**	**87.9**	**-**	**81.0**	**7,100**	**GAS**	**-**	**-**	**2,160,880.0**	**14,864,721**	**4.88**	**-**
46. POLK #2 CT (GAS)	150	90	0.1	-	60.0	13,667	GAS	1,200	1,025,000	1,230.0	8,487	9.43	7.07
47. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	47,413	31.61	142.38
48. POLK #2 TOTAL	[4] **150**	**240**	**0.2**	**-**	**77.7**	**13,250**	**-**	**-**	**-**	**3,180.0**	**55,900**	**23.29**	**-**
49. POLK #3 CT (GAS)	150	360	0.3	-	60.0	12,639	GAS	4,430	1,027,088	4,550.0	31,327	8.70	7.07
50. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	47,270	31.51	142.38
51. POLK #3 TOTAL	[4] **150**	**510**	**0.5**	**-**	**67.2**	**12,745**	**-**	**-**	**-**	**6,500.0**	**78,597**	**15.41**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2023

(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)
52. POLK #4 CT (GAS) TOTAL	[4]	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
53. POLK #5 CT (GAS) TOTAL	[4]	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
54. POLK #2 CC TOTAL		1,080	305,080	39.2	97.4	80.9	7,115	-	-	-	2,170,560.0	14,999,218	4.92	-
55. POLK STATION TOTAL		1,325	327,930	34.3	96.8	80.6	7,236	-	-	-	2,372,900.0	16,391,202	5.00	-
56. BAYSIDE #1		720	150,140	28.9	25.8	34.6	7,883	GAS	1,151,260	1,028,004	1,183,500.0	8,141,311	5.42	7.07
57. BAYSIDE #2		954	35,830	5.2	97.3	16.3	9,287	GAS	323,680	1,027,991	332,740.0	2,288,952	6.39	7.07
58. BAYSIDE #3		56	1,040	2.6	98.6	80.7	12,029	GAS	12,180	1,027,094	12,510.0	86,133	8.28	7.07
59. BAYSIDE #4		56	770	1.9	98.6	85.9	12,000	GAS	9,000	1,026,667	9,240.0	63,645	8.27	7.07
60. BAYSIDE #5		56	1,030	2.6	98.6	80.0	11,981	GAS	12,000	1,028,333	12,340.0	84,860	8.24	7.07
61. BAYSIDE #6		56	1,140	2.8	98.6	84.8	11,763	GAS	13,030	1,029,163	13,410.0	92,144	8.08	7.07
62. BAYSIDE STATION TOTAL		1,898	189,950	13.9	70.3	28.8	8,232	GAS	1,521,150	1,027,999	1,563,740.0	10,757,045	5.66	7.07
63. SYSTEM TOTAL		6,351	1,456,110	31.8	59.9	104.8	6,330	-	-	-	9,216,930.0	61,682,842	4.24	-

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

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2023

(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	19.7	160	1.1	-	1.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	2,670	256.3	-	256.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	8,430	16.2	-	16.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	8,730	15.8	-	15.8	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	10,300	18.6	-	18.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.9	7,000	15.4	-	15.4	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	55.2	6,420	15.6	-	15.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,010	18.0	-	18.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.3	5,580	15.2	-	15.2	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	10,370	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	10,350	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	7,600	17.1	-	17.1	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	31.4	3,090	13.2	-	13.2	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	5,350	9.7	-	9.7	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	54.4	7,300	18.0	-	18.0	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	8,930	16.2	-	16.2	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	14.2	5,410	51.2	-	51.2	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	55.0	6,020	14.7	-	14.7	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	1,380	2.6	-	2.6	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	61.0	6,890	15.2	-	15.2	-	SOLAR	-	-	-	-	-	-
22. FUTURE SOLAR	25.0	2,280	12.3	-	12.3	-	SOLAR	-	-	-	-	-	-
23. FUTURE SOLAR	60.0	5,930	13.3	-	13.3	-	SOLAR	-	-	-	-	-	-
24. FUTURE SOLAR	74.5	7,360	13.3	-	13.3	-	SOLAR	-	-	-	-	-	-
25. FUTURE SOLAR	74.5	7,360	13.3	-	13.3	-	SOLAR	-	-	-	-	-	-
26. SOLAR TOTAL (3)	**1321.5**	**150,180**	**15.3**	**-**	**15.3**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
27. BIG BEND #1 CC TOTAL	**1,120**	**776,200**	**93.1**	**98.0**	**95.5**	**6,279**	**GAS**	**4,741,110**	**1,028,000**	**4,873,860.0**	**34,626,944**	**4.46**	**7.30**
28. BIG BEND #2 TOTAL	**350**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.#3 (GAS)	355	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
30. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
31. BIG BEND #3 TOTAL	**355**	**0**	**0.0**	**82.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
32. B.B.#4 (GAS)	160	12,180	10.2	-	-	-	GAS	134,400	1,028,051	138,170.0	981,597	8.06	7.30
33. B.B.#4 (COAL)	432	69,010	21.5	-	-	-	COAL	34,800	22,498,851	782,960.0	3,142,712	4.55	90.31
34. BIG BEND #4 TOTAL	**432**	**81,190**	**25.3**	**89.3**	**58.7**	**11,345**		**-**	**-**	**921,130.0**	**4,124,309**	**5.08**	**-**
35. B.B. IGNITION	-	-	-	-	-	-	GAS	7,090	1,028,209	7,290.0	51,782	-	7.30
36. B.B.C.T.#4 TOTAL	**61**	**320**	**0.7**	**98.3**	**52.5**	**13,188**	**GAS**	**4,100**	**1,029,268**	**4,220.0**	**29,945**	**9.36**	**7.30**
37. B.B.C.T.#5 TOTAL	**350**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. B.B.C.T.#6 TOTAL	**350**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. BIG BEND STATION TOTAL	**3,018**	**857,710**	**38.2**	**60.8**	**80.5**	**6,761**	**-**	**-**	**-**	**5,799,210.0**	**38,832,980**	**4.53**	**-**
40. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
41. POLK #1 CT (GAS)	230	16,700	9.8	-	74.1	8,954	GAS	145,460	1,027,980	149,530.0	1,062,375	6.36	7.30
42. POLK #1 TOTAL	**230**	**16,700**	**9.8**	**93.8**	**74.1**	**8,954**	**-**	**-**	**-**	**149,530.0**	**1,062,375**	**6.36**	**-**
43. POLK #2 ST DUCT FIRING	120	2,610	2.9	-	57.2	8,157	GAS	20,710	1,028,006	21,290.0	151,257	5.80	7.30
44. POLK #2 ST W/O DUCT FIRING	360	242,600	-	-	-	-		1,677,745	1,028,005	1,724,730.0	12,253,498	5.05	7.30
45. POLK #2 ST TOTAL	**480**	**245,210**	**68.7**	**-**	**81.2**	**7,121**	**GAS**	**-**	**-**	**1,746,020.0**	**12,404,755**	**5.06**	**-**
46. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	(1)	0.00	0.00
47. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	47,403	31.60	142.35
48. POLK #2 TOTAL (4)	**180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,402**	**31.60**	**-**
49. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
50. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	47,260	31.51	142.35
51. POLK #3 TOTAL (4)	**180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**47,260**	**31.51**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2023

(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)
52. POLK #4 CT (GAS) TOTAL	[4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
53. POLK #5 CT (GAS) TOTAL	[4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
54. POLK #2 CC TOTAL		**1,200**	**245,510**	**27.5**	**81.7**	**81.2**	**7,128**	**-**	**-**	**-**	**1,749,920.0**	**12,499,417**	**5.09**	**-**
55. POLK STATION TOTAL		**1,430**	**262,210**	**24.6**	**83.7**	**80.3**	**7,244**	**-**	**-**	**-**	**1,899,450.0**	**13,561,792**	**5.17**	**-**
56. BAYSIDE #1		792	127,940	21.7	96.6	33.2	7,699	GAS	958,180	1,028,001	985,010.0	6,998,118	5.47	7.30
57. BAYSIDE #2		1,047	136,560	17.5	97.3	18.3	8,615	GAS	1,144,450	1,027,996	1,176,490.0	8,358,550	6.12	7.30
58. BAYSIDE #3		61	310	0.7	98.6	46.2	13,742	GAS	4,140	1,028,986	4,260.0	30,237	9.75	7.30
59. BAYSIDE #4		61	270	0.6	98.6	44.3	14,148	GAS	3,730	1,024,129	3,820.0	27,242	10.09	7.30
60. BAYSIDE #5		61	260	0.6	98.6	42.6	14,500	GAS	3,670	1,027,248	3,770.0	26,804	10.31	7.30
61. BAYSIDE #6		61	310	0.7	98.6	46.2	13,903	GAS	4,200	1,026,190	4,310.0	30,675	9.90	7.30
62. BAYSIDE STATION TOTAL		**2,083**	**265,650**	**17.1**	**97.2**	**23.4**	**8,197**	**GAS**	**2,118,370**	**1,027,989**	**2,177,660.0**	**15,471,626**	**5.82**	**7.30**
63. SYSTEM TOTAL		**7,853**	**1,535,750**	**26.3**	**64.4**	**62.9**	**6,431**	**-**	**-**	**-**	**9,876,320.0**	**67,866,398**	**4.42**	**-**

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

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2023 THROUGH JUNE 2023

		Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23
	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)	665	665	665	665	665	665
16.	UNIT COST ($/BBL)	146.18	146.18	146.18	146.18	146.18	146.18
17.	AMOUNT ($)	97,210	97,210	97,210	97,210	97,210	97,210
18.	BURNED:						
19.	UNITS (BBL)	665	665	665	665	665	665
20.	UNIT COST ($/BBL)	141.93	142.00	142.06	142.13	142.20	142.26
21.	AMOUNT ($)	94,382	94,428	94,473	94,517	94,561	94,604
22.	ENDING INVENTORY:						
23.	UNITS (BBL)	40,483	40,483	40,483	40,483	40,483	40,483
24.	UNIT COST ($/BBL)	141.89	141.96	142.03	142.09	142.16	142.22
25.	AMOUNT ($)	5,744,215	5,746,997	5,749,735	5,752,427	5,755,077	5,757,683
26.	DAYS SUPPLY: NORMAL	1,851,205	1,851,205	1,856,276	1,856,276	1,856,276	1,856,276
27.	DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
	COAL						
28.	PURCHASES:						
29.	UNITS (TONS)	41,850	41,650	41,650	41,650	41,650	41,650
30.	UNIT COST ($/TON)	91.44	91.44	91.44	91.44	91.44	91.44
31.	AMOUNT ($)	3,826,938	3,808,649	3,808,649	3,808,649	3,808,649	3,808,649
32.	BURNED:						
33.	UNITS (TONS)	107,170	30,760	39,630	0	0	31,490
34.	UNIT COST ($/TON)	70.66	75.84	78.11	0.00	0.00	85.38
35.	AMOUNT ($)	7,572,646	2,332,840	3,095,472	0	0	2,688,592
36.	ENDING INVENTORY:						
37.	UNITS (TONS)	141,180	152,070	154,090	195,740	237,390	247,550
38.	UNIT COST ($/TON)	68.98	74.02	77.78	80.69	82.58	83.76
39.	AMOUNT ($)	9,737,961	11,256,212	11,985,419	15,794,068	19,602,717	20,735,511
40.	DAYS SUPPLY:	72	192	358	566	328	205
	NATURAL GAS						
41.	PURCHASES:						
42.	UNITS (MCF)	8,078,345	7,825,885	8,544,725	9,028,365	10,775,735	11,452,675
43.	UNIT COST ($/MCF)	11.17	10.53	8.99	7.16	6.98	6.91
44.	AMOUNT ($)	90,260,834	82,376,494	76,853,956	64,687,863	75,187,616	79,141,950
45.	BURNED:						
46.	UNITS (MCF)	8,078,345	7,825,885	8,544,725	9,028,365	10,775,735	11,452,675
47.	UNIT COST ($/MCF)	11.17	10.55	9.06	7.24	6.98	6.91
48.	AMOUNT ($)	90,234,675	82,560,414	77,401,396	65,383,943	75,257,856	79,122,190
49.	ENDING INVENTORY:						
50.	UNITS (MCF)	389,105	389,105	389,105	389,105	389,105	389,105
51.	UNIT COST ($/MCF)	8.85	8.38	6.98	5.19	5.01	5.06
52.	AMOUNT ($)	3,445,440	3,261,520	2,714,080	2,018,001	1,947,760	1,967,520
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 2023 THROUGH DECEMBER 2023

		Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	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)	665	665	665	665	665	665	7,980
16.	UNIT COST ($/BBL)	146.18	145.11	143.81	142.57	141.49	140.50	144.73
17.	AMOUNT ($)	97,210	96,498	95,632	94,809	94,090	93,435	1,154,934
18.	BURNED:							
19.	UNITS (BBL)	665	665	665	665	665	665	7,980
20.	UNIT COST ($/BBL)	142.32	142.37	142.39	142.40	142.38	142.35	142.23
21.	AMOUNT ($)	94,646	94,676	94,691	94,693	94,683	94,663	1,135,017
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	40,483	40,483	40,483	40,483	40,483	40,483	40,483
24.	UNIT COST ($/BBL)	142.29	142.33	142.36	142.36	142.34	142.31	142.31
25.	AMOUNT ($)	5,760,248	5,762,070	5,763,011	5,763,127	5,762,533	5,761,305	5,761,305
26.	DAYS SUPPLY: NORMAL	1,856,276	1,856,276	1,856,276	1,856,276	1,856,276	1,856,276	-
27.	DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	41,650	41,650	41,650	41,650	41,650	41,650	500,000
30.	UNIT COST ($/TON)	91.44	91.44	91.44	91.44	91.44	91.44	91.44
31.	AMOUNT ($)	3,808,649	3,808,649	3,808,649	3,808,649	3,808,649	3,808,649	45,722,077
32.	BURNED:							
33.	UNITS (TONS)	35,080	44,270	66,390	77,130	28,050	34,800	494,770
34.	UNIT COST ($/TON)	86.50	88.11	88.23	89.00	89.73	90.31	82.88
35.	AMOUNT ($)	3,034,523	3,900,479	5,857,911	6,864,534	2,516,837	3,142,712	41,006,546
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	254,120	251,500	226,760	191,280	204,880	211,730	211,730
38.	UNIT COST ($/TON)	84.70	85.41	85.81	85.91	86.57	86.98	86.98
39.	AMOUNT ($)	21,523,826	21,479,903	19,457,495	16,432,808	17,735,966	18,415,979	18,415,979
40.	DAYS SUPPLY:	160	123	120	126	111	112	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	12,118,035	12,354,675	11,012,615	10,022,165	8,353,255	8,848,985	118,415,460
43.	UNIT COST ($/MCF)	6.95	6.94	6.99	7.09	7.08	7.31	7.69
44.	AMOUNT ($)	84,208,461	85,723,879	76,957,035	71,059,854	59,135,882	64,717,663	910,311,487
45.	BURNED:							
46.	UNITS (MCF)	12,118,035	12,354,675	11,012,615	10,022,165	8,353,255	8,848,985	118,415,460
47.	UNIT COST ($/MCF)	6.95	6.94	6.99	7.09	7.07	7.30	7.70
48.	AMOUNT ($)	84,186,701	85,720,520	76,965,835	71,039,133	59,071,322	64,629,023	911,573,008
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	389,105	389,105	389,105	389,105	389,105	389,105	389,105
51.	UNIT COST ($/MCF)	5.11	5.12	5.10	5.15	5.32	5.55	5.55
52.	AMOUNT ($)	1,989,280	1,992,640	1,983,840	2,004,561	2,069,120	2,157,760	2,157,760
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
ESTIMATED FOR THE PERIOD: JANUARY 2023 THROUGH JUNE 2023

SCHEDULE E6

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH WHEELED		CENTS/KWH				
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON SALES
Jan-23	SEMINOLE JURISD.	SCH. - D	4,140.0	0.0	4,140.0	6.406	7.001	265,220.00	289,859.00	24,639.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**4,140.0**	**0.0**	**4,140.0**	**6.406**	**7.001**	**265,220.00**	**289,859.00**	**24,639.00**
Feb-23	SEMINOLE JURISD.	SCH. - D	4,260.0	0.0	4,260.0	6.153	6.724	262,110.00	286,460.00	24,350.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**4,260.0**	**0.0**	**4,260.0**	**6.153**	**6.724**	**262,110.00**	**286,460.00**	**24,350.00**
Mar-23	SEMINOLE JURISD.	SCH. - D	3,950.0	0.0	3,950.0	5.323	5.817	210,250.00	229,782.00	19,532.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**3,950.0**	**0.0**	**3,950.0**	**5.323**	**5.817**	**210,250.00**	**229,782.00**	**19,532.00**
Apr-23	SEMINOLE JURISD.	SCH. - D	2,550.0	0.0	2,550.0	4.129	4.512	105,280.00	115,061.00	9,781.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,550.0**	**0.0**	**2,550.0**	**4.129**	**4.512**	**105,280.00**	**115,061.00**	**9,781.00**
May-23	SEMINOLE JURISD.	SCH. - D	3,290.0	0.0	3,290.0	4.174	4.562	137,340.00	150,099.00	12,759.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**3,290.0**	**0.0**	**3,290.0**	**4.174**	**4.562**	**137,340.00**	**150,099.00**	**12,759.00**
Jun-23	SEMINOLE JURISD.	SCH. - D	2,460.0	0.0	2,460.0	4.310	4.711	106,030.00	115,880.00	9,850.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,460.0**	**0.0**	**2,460.0**	**4.310**	**4.711**	**106,030.00**	**115,880.00**	**9,850.00**

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2023 THROUGH DECEMBER 2023

SCHEDULE E6

(1)	(2)	(3)		(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH		CENTS/KWH				
					WHEELED						
		TYPE		TOTAL	FROM	MWH	(A)	(B)	TOTAL $		
		&		MWH	OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST	GAINS ON
MONTH	SOLD TO	SCHEDULE		SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$	SALES
Jul-23	SEMINOLE	JURISD.	SCH. - D	2,660.0	0.0	2,660.0	4.314	4.714	114,740.00	125,399.00	10,659.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,660.0**	**0.0**	**2,660.0**	**4.314**	**4.714**	**114,740.00**	**125,399.00**	**10,659.00**
Aug-23	SEMINOLE	JURISD.	SCH. - D	2,860.0	0.0	2,860.0	4.383	4.790	125,360.00	137,006.00	11,646.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,860.0**	**0.0**	**2,860.0**	**4.383**	**4.790**	**125,360.00**	**137,006.00**	**11,646.00**
Sep-23	SEMINOLE	JURISD.	SCH. - D	3,830.0	0.0	3,830.0	4.509	4.927	172,680.00	188,722.00	16,042.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**3,830.0**	**0.0**	**3,830.0**	**4.509**	**4.927**	**172,680.00**	**188,722.00**	**16,042.00**
Oct-23	SEMINOLE	JURISD.	SCH. - D	3,240.0	0.0	3,240.0	4.569	4.993	148,020.00	161,771.00	13,751.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**3,240.0**	**0.0**	**3,240.0**	**4.569**	**4.993**	**148,020.00**	**161,771.00**	**13,751.00**
Nov-23	SEMINOLE	JURISD.	SCH. - D	3,760.0	0.0	3,760.0	4.181	4.569	157,200.00	171,804.00	14,604.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**3,760.0**	**0.0**	**3,760.0**	**4.181**	**4.569**	**157,200.00**	**171,804.00**	**14,604.00**
Dec-23	SEMINOLE	JURISD.	SCH. - D	3,120.0	0.0	3,120.0	4.272	4.669	133,300.00	145,684.00	12,384.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**3,120.0**	**0.0**	**3,120.0**	**4.272**	**4.669**	**133,300.00**	**145,684.00**	**12,384.00**
TOTAL											
Jan-23	SEMINOLE	JURISD.	SCH. - D	40,120.0	0.0	40,120.0	4.829	5.278	1,937,530.00	2,117,527.00	179,997.00
THRU	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
Dec-23	**TOTAL**			**40,120.0**	**0.0**	**40,120.0**	**4.829**	**5.278**	**1,937,530.00**	**2,117,527.00**	**179,997.00**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2023 THROUGH DECEMBER 2023

SCHEDULE E7

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUSTMENT
Jan-23	VARIOUS	FIRM	50.0	0.0	0.0	50.0	10.160	10.160	5,080.00
	TOTAL		50.0	0.0	0.0	50.0	10.160	10.160	5,080.00
Feb-23	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
Mar-23	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-23	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-23	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-23	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-23	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-23	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-23	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-23	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-23	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-23	VARIOUS	FIRM	140.0	0.0	0.0	140.0	9.850	9.850	13,790.00
	TOTAL		140.0	0.0	0.0	140.0	9.850	9.850	13,790.00
TOTAL Jan-23	VARIOUS	FIRM	190.0	0.0	0.0	190.0	9.932	9.932	18,870.00
THRU Dec-23	TOTAL		190.0	0.0	0.0	190.0	9.932	9.932	18,870.00

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2023 THROUGH DECEMBER 2023

SCHEDULE E8

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUST-MENT
Jan-23	VARIOUS	CO-GEN.							
		AS AVAIL.	5,740.0	0.0	0.0	5,740.0	3.203	3.203	183,860.00
	TOTAL		5,740.0	0.0	0.0	5,740.0	3.203	3.203	183,860.00
Feb-23	VARIOUS	CO-GEN.							
		AS AVAIL.	5,240.0	0.0	0.0	5,240.0	3.102	3.102	162,520.00
	TOTAL		5,240.0	0.0	0.0	5,240.0	3.102	3.102	162,520.00
Mar-23	VARIOUS	CO-GEN.							
		AS AVAIL.	5,500.0	0.0	0.0	5,500.0	2.629	2.629	144,580.00
	TOTAL		5,500.0	0.0	0.0	5,500.0	2.629	2.629	144,580.00
Apr-23	VARIOUS	CO-GEN.							
		AS AVAIL.	5,190.0	0.0	0.0	5,190.0	2.547	2.547	132,170.00
	TOTAL		5,190.0	0.0	0.0	5,190.0	2.547	2.547	132,170.00
May-23	VARIOUS	CO-GEN.							
		AS AVAIL.	5,510.0	0.0	0.0	5,510.0	2.775	2.775	152,920.00
	TOTAL		5,510.0	0.0	0.0	5,510.0	2.775	2.775	152,920.00
Jun-23	VARIOUS	CO-GEN.							
		AS AVAIL.	5,420.0	0.0	0.0	5,420.0	2.608	2.608	141,350.00
	TOTAL		5,420.0	0.0	0.0	5,420.0	2.608	2.608	141,350.00
Jul-23	VARIOUS	CO-GEN.							
		AS AVAIL.	5,310.0	0.0	0.0	5,310.0	3.105	3.105	164,850.00
	TOTAL		5,310.0	0.0	0.0	5,310.0	3.105	3.105	164,850.00
Aug-23	VARIOUS	CO-GEN.							
		AS AVAIL.	5,330.0	0.0	0.0	5,330.0	2.589	2.589	138,020.00
	TOTAL		5,330.0	0.0	0.0	5,330.0	2.589	2.589	138,020.00
Sep-23	VARIOUS	CO-GEN.							
		AS AVAIL.	5,550.0	0.0	0.0	5,550.0	2.633	2.633	146,150.00
	TOTAL		5,550.0	0.0	0.0	5,550.0	2.633	2.633	146,150.00
Oct-23	VARIOUS	CO-GEN.							
		AS AVAIL.	5,580.0	0.0	0.0	5,580.0	2.543	2.543	141,890.00
	TOTAL		5,580.0	0.0	0.0	5,580.0	2.543	2.543	141,890.00
Nov-23	VARIOUS	CO-GEN.							
		AS AVAIL.	4,920.0	0.0	0.0	4,920.0	2.644	2.644	130,070.00
	TOTAL		4,920.0	0.0	0.0	4,920.0	2.644	2.644	130,070.00
Dec-23	VARIOUS	CO-GEN.							
		AS AVAIL.	5,680.0	0.0	0.0	5,680.0	2.631	2.631	149,440.00
	TOTAL		5,680.0	0.0	0.0	5,680.0	2.631	2.631	149,440.00
TOTAL	VARIOUS	CO-GEN.							
Jan-23		AS AVAIL.	64,970.0	0.0	0.0	64,970.0	2.752	2.752	1,787,820.00
THRU	TOTAL		64,970.0	0.0	0.0	64,970.0	2.752	2.752	1,787,820.00
Dec-23									

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2023 THROUGH DECEMBER 2023

SCHEDULE E9

(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-23	VARIOUS	SCH. - J	700.0	0.0	700.0	18.899	132,290.00	69.407	485,850.00	353,560.00
Feb-23	VARIOUS	SCH. - J	0.0	0.0	0.0	0.000	0.00	0.000	725,180.00	725,180.00
Mar-23	VARIOUS	SCH. - J	930.0	0.0	930.0	7.844	72,950.00	127.173	1,182,710.00	1,109,760.00
Apr-23	VARIOUS	SCH. - J	340.0	0.0	340.0	7.306	24,840.00	255.606	869,060.00	844,220.00
May-23	VARIOUS	SCH. - J	1,470.0	0.0	1,470.0	4.382	64,420.00	133.584	1,963,690.00	1,899,270.00
Jun-23	VARIOUS	SCH. - J	1,000.0	0.0	1,000.0	6.448	64,480.00	160.602	1,606,020.00	1,541,540.00
Jul-23	VARIOUS	SCH. - J	480.0	0.0	480.0	12.015	57,670.00	409.646	1,966,300.00	1,908,630.00
Aug-23	VARIOUS	SCH. - J	2,060.0	0.0	2,060.0	8.044	165,710.00	98.803	2,035,350.00	1,869,640.00
Sep-23	VARIOUS	SCH. - J	11,080.0	0.0	11,080.0	12.109	1,341,690.00	56.993	6,314,820.00	4,973,130.00
Oct-23	VARIOUS	SCH. - J	10,010.0	0.0	10,010.0	7.141	714,780.00	51.120	5,117,070.00	4,402,290.00
Nov-23	VARIOUS	SCH. - J	7,390.0	0.0	7,390.0	6.315	466,690.00	43.765	3,234,240.00	2,767,550.00
Dec-23	VARIOUS	SCH. - J	1,200.0	0.0	1,200.0	18.629	223,550.00	80.659	967,910.00	744,360.00
TOTAL	VARIOUS	SCH. - J	**36,660.0**	**0.0**	**36,660.0**	**9.081**	**3,329,070.00**	**72.199**	**26,468,200.00**	**23,139,130.00**

SCHEDULE E10

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

	Current Apr 2022 - Aug 2022	Current Sep 2022 - Dec 2022	Projected Jan 2023 - Dec 2023	Difference $	Difference %
Base Rate Revenue [1]	78.69	79.46	86.22	6.76	8.5%
Fuel Recovery Revenue	37.91	37.91	45.25	7.34	19.4%
Conservation Revenue	2.36	2.36	2.81	0.45	19.1%
Capacity Revenue	0.53	0.53	(0.18)	(0.71)	-134.0%
Environmental Revenue	1.38	1.38	0.92	(0.46)	-33.3%
Storm Protection Plan Revenue	3.29	3.29	3.76	0.47	14.3%
Clean Energy Transition Mechanism	4.41	4.41	4.41	0.00	0.0%
Florida Gross Receipts Tax Revenue	3.30	3.32	3.67	0.35	10.5%
TOTAL REVENUE	**$131.87**	**$132.66**	**$146.86**	**$14.20**	**10.7%**

(1) Includes Proposed 2023 Generation Base Rate Adjustment provision in the 2021 Agreement

SCHEDULE H1

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

	ACTUAL 2020	ACTUAL 2021	ACT/EST 2022	EST 2023	DIFFERENCE (%) 2021-2020	2022-2021	2023-2022
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL [1]	636,201	833,691	2,830,275	1,135,017	31.0%	239.5%	-59.9%
3 COAL	33,991,967	48,429,754	41,102,981	41,006,546	42.5%	-15.1%	-0.2%
4 NATURAL GAS	379,848,073	613,516,607	999,057,535	911,573,008	61.5%	62.8%	-8.8%
5 SOLAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**414,476,241**	**662,780,052**	**1,042,990,791**	**953,714,571**	**59.9%**	**57.4%**	**-8.6%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL [1]	1,901	2,024	7,336	3,600	6.5%	262.5%	-50.9%
10 COAL	903,680	1,340,015	1,266,597	1,013,080	48.3%	-5.5%	-20.0%
11 NATURAL GAS	16,519,857	16,142,165	17,047,483	17,542,780	-2.3%	5.6%	2.9%
12 SOLAR	1,119,822	1,252,466	1,751,392	2,399,520	11.8%	39.8%	37.0%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	**18,545,260**	**18,736,670**	**20,072,808**	**20,958,980**	**1.0%**	**7.1%**	**4.4%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) [1]	4,345	5,880	20,684	7,980	35.3%	251.8%	-61.4%
17 COAL (TON)	431,512	637,962	611,561	494,770	47.8%	-4.1%	-19.1%
18 NATURAL GAS (MCF)	127,992,191	124,139,525	126,142,120	118,415,460	-3.0%	1.6%	-6.1%
19 SOLAR	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]	25,328	34,272	120,715	46,800	35.3%	252.2%	-61.2%
23 COAL	9,830,729	14,535,162	13,776,770	11,132,550	47.9%	-5.2%	-19.2%
24 NATURAL GAS	131,021,110	126,980,604	129,656,183	121,654,380	-3.1%	2.1%	-6.2%
25 SOLAR	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)	**140,877,167**	**141,550,038**	**143,553,668**	**132,833,730**	**0.5%**	**1.4%**	**-7.5%**
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]	0.01	0.01	0.04	0.02	0.0%	300.0%	-50.0%
30 COAL	4.87	7.16	6.30	4.83	47.0%	-12.0%	-23.3%
31 NATURAL GAS	89.08	86.15	84.93	83.70	-3.3%	-1.4%	-1.4%
32 SOLAR	6.04	6.68	8.73	11.45	10.6%	30.7%	31.2%
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]	146.42	141.78	136.83	142.23	-3.2%	-3.5%	3.9%
37 COAL ($/TON)	78.77	75.91	67.21	82.88	-3.6%	-11.5%	23.3%
38 NATURAL GAS ($/MCF)	2.97	4.94	7.92	7.70	66.3%	60.3%	-2.8%
39 SOLAR	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 ($/MMBTU)							
41 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
42 LIGHT OIL [1]	25.12	24.33	23.45	24.25	-3.1%	-3.6%	3.4%
43 COAL	3.46	3.33	2.98	3.68	-3.8%	-10.5%	23.5%
44 NATURAL GAS	2.90	4.83	7.71	7.49	66.6%	59.6%	-2.9%
45 SOLAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL ($/MMBTU)	**2.94**	**4.68**	**7.27**	**7.18**	**59.2%**	**55.3%**	**-1.2%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL [1]	13,324	16,933	16,455	13,000	27.1%	-2.8%	-21.0%
50 COAL	10,879	10,847	10,877	10,989	-0.3%	0.3%	1.0%
51 NATURAL GAS	7,931	7,866	7,606	6,935	-0.8%	-3.3%	-8.8%
52 SOLAR	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)	**7,596**	**7,555**	**7,152**	**6,338**	**-0.5%**	**-5.3%**	**-11.4%**
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]	33.47	41.19	38.58	31.53	23.1%	-6.3%	-18.3%
57 COAL	3.76	3.61	3.25	4.05	-4.0%	-10.0%	24.6%
58 NATURAL GAS	2.30	3.80	5.86	5.20	65.2%	54.2%	-11.3%
59 SOLAR	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)	**2.23**	**3.54**	**5.20**	**4.55**	**58.7%**	**46.9%**	**-12.5%**

[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 2023 - DECEMBER 2023

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period January 2023 through December 2023

	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	6,858,868	4.832	331,420,508	4.525	310,363,783
TIER II (Over 1,000) kWh	3,038,488	4.832	146,819,763	5.525	167,876,488
Total	9,897,357		478,240,271		478,240,271

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTIONS
JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY AND EXHIBIT
OF
PATRICK A. BOKOR

FILED: SEPTEMBER 2, 2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PATRICK A. BOKOR

Q. Please state your name, address, occupation, and employer.

A. My name is Patrick A. Bokor. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Gas & Power Trading.

Q. Please provide a brief description of your educational background and work experience.

A. I received a Bachelor of Science degree in Accounting in 2000 from the University of Florida and a Master of Business Administration in 2010 from the University of Tampa. I have over 16 years of experience in the electric industry, in the areas of unit commitment and economic dispatch, power and gas trading, accounting, finance, and risk management. In my current role, I am responsible for managing the procurement and delivery of wholesale natural gas and power for Tampa Electric's portfolio.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric’s methodology for determining the various factors required to compute the Generating Performance Incentive Factor (“GPIF”) as ordered by the Commission.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. Exhibit No. PAB-2, consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2023 period.

Q. Which generating units on Tampa Electric’s system are included in the determination of the GPIF?

A. Three natural gas combined cycle (“CC”) units and one coal unit are included. These are Polk Unit 2, Bayside Units 1 and 2, and Big Bend Unit 4.

Q. Does your exhibit comply with the Commission’s approved GPIF methodology?

A. Yes. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80 percent of the estimated system net generation. The units Tampa Electric proposes to use for the period January 2023 through December 2023 represent the top 97.4 percent of the total forecasted system net generation for this period excluding the Big Bend Unit 1 CC (Big Bend Modernization). The Big Bend Unit 1 CC is expected to enter commercial service in December 2022 and was excluded from the GPIF calculation because the company does not have historical operational data on which to base targets.

To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. The methodology was approved by the Commission in Order No. PSC-2006-1057-FOF-EI issued in Docket No. 20060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes, Big Bend Unit 4 and Polk Unit 2 outages were identified as outliers and were removed.

Q. Did Tampa Electric make any other adjustments?

A. Yes. As allowed per Section 4.3 of the GPIF Implementation Manual, the Forced Outage and Maintenance Outage Factors were adjusted to reflect recent unit performance and known unit modifications or equipment changes.

Q. Please describe how Tampa Electric developed the various factors associated with GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2023 period. A range of potential improvements and degradations were determined for each of these metrics.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100 percent to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the four units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2023 period, the projected EUOF for Big Bend Unit 4 is 19.9 percent, the POF is 18.9 percent. Therefore, the target EAF for Big Bend Unit 4 equals 61.2 percent or:

$$100\% - (19.9\% + 18.9\%) = 61.2\%$$

This is shown on Page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived using the following formula:

$$EAF_{MAX} = 1 – [0.80\ (EUOF_T) + 0.95\ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. Calculating the maximum incentive points, a 20 percent reduction in EUOF, plus a five percent reduction in the POF is necessary. Continuing with the Big Bend Unit 4 example:

$$EAF_{MAX} = 1 – [0.80\ (19.9\%) + 0.95\ (18.9\%)] = 66.1\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing using the Big Bend Unit 4 example,

$$EAF_{MIN} = 1 - [1.40\ (19.9\%) + 1.10\ (18.9\%)] = 51.4\%$$

The equivalent availability maximum and minimum for the other four units are computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company’s planned outages for January 2023 through December 2023 are shown on page 15 of Document No. 1. Two GPIF units have a major planned outage of 28 days or greater in 2023; therefore, two Critical Path Method Diagrams are provided.

Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 4 is scheduled for planned outages from April 1, 2023 to May 25, 2023 and from November 7, 2023 to November 20, 2023. There are 1,656 planned outage hours scheduled for the 2023 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Big Bend Unit 4 is 18.9 percent or:

$$\frac{1,656}{8,760} \times 100\% = 18.9\%$$

The factor for each unit is shown on pages 5 and 11 through 14 of Document No. 1. Polk Unit 2 has a POF of 3.8 percent, Bayside Unit 1 has a POF of 5.3 percent, and Bayside Unit 2 has a POF of 21.8 percent.

Q. How did you determine the Forced Outage and Maintenance

Outage Factors for each unit?

A. Projected factors are based upon historical unit performance. For each unit, the three most recent July through June annual periods formed the basis of the target development. Historical data and target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 19.9 percent for Big Bend Unit 4. The EUOF of Big Bend Unit 4 is verified by the data shown on page 11, lines 3, 5, 10, and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

Or

$$EUOF = \frac{(1{,}049 + 695)}{8{,}760} \times 100\% = 19.9\%$$

Relative to Big Bend Unit 4, the EUOF of 19.9 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Polk Unit 2

The projected EUOF for this unit is 5.3 percent. The unit will have two planned outages in 2023, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 90.9 percent.

Bayside Unit 1

The projected EUOF for this unit is 4.7 percent. The unit will have one planned outage in 2023, and the POF is 5.3 percent. Therefore, the target equivalent availability for this unit is 90.0 percent.

Bayside Unit 2

The projected EUOF for this unit is 3.1 percent. The unit will have one planned outage in 2023, and the POF is 21.8 percent. Therefore, the target equivalent availability for this unit is 75.2 percent.

Big Bend Unit 4

The projected EUOF for this unit is 19.9 percent. The unit will have two planned outages in 2023, and the POF is 18.9 percent. Therefore, the target equivalent availability for this unit is 61.2 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 81.6 percent is shown on page 5 of Document No. 1.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend Unit 4 on page 11 of Document No. 1. Except for the months of May and November, the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled for these months. During the months of May and November, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to the scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining unit metrics, which are subsequently converted to factors. Therefore,

$$EFOF + EMOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the afore mentioned agreed upon GPIF methodology.

Q. How were the targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis for the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any period of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 22 through 25 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by the computer program for each unit. These curves are also used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch and fuel.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2023 period.

A. The heat rate target for Polk Unit 2 is 7,279 Btu/Net kWh with a range of ±191 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,481 Btu/Net kWh with a range of ±174 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 8,280 Btu/Net kWh with a range of ±302 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,777 Btu/Net kWh with a range of ±720 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within a range for each target. This is shown on pages 7 through 10 of Document No. 1.

Q. Do these heat rate targets and ranges meet the Commission's requirements?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in determining the GPIF targets?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown in Document No. 1, pages 7 through 10. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $831,414,630 is shown on Document No. 1, page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

Column 4 totals $17,848,884 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing unit savings by the total. For Big Bend Unit 4, the weighting factor for average net operating heat rate is 26.52 percent as shown in the right-hand column on Document No. 1, page 6. Pages 7 through 10 of Document

No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, as shown on page 7 of Document No. 1, if Big Bend Unit 4, operates at 10,058 average net operating heat rate, fuel savings would equal $4,734,231 and +10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 of Document No. 1 is a summary of the tables on pages 7 through 10. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $17,848,884. The right-hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January 2023 through December 2023 is $4,460,054,782. This produces the maximum allowed jurisdictional incentive of $14,976,288 shown on line 21.

Q. Are there any constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. As Order No. PSC-2013-0665-FOF-EI, issued in Docket No. 20130001-EI on December 18, 2013 states, incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $8,924,442.

Q. Please summarize your direct testimony.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP).

$$\begin{aligned} GPIP = (&0.0787\ EAP_{PK2} + 0.0594\ EAP_{BAY1} \\ &+ 0.0113\ EAP_{BAY2} + 0.0566\ EAP_{BB4} \\ &+ 0.2852\ HRP_{PK2} + 0.1460\ HRP_{BAY1} \\ &+ 0.0976\ HRP_{BAY2} + 0.2652\ HRP_{BB4}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points

EAP = Equivalent Availability Points awarded/deducted for Polk Unit 2, Bayside Units 1 and 2, and Big Bend Unit 4.

HRP = Average Net Heat Rate Points awarded/deducted for Polk Unit 2, Bayside Units 1 and 2, and Big Bend Unit 4.

Q. Have you prepared a document summarizing the GPIF targets for the January 2023 through December 2023 period?

A. Yes. Document No. 2 entitled “Summary of GPIF Targets” provides the availability and heat rate targets for each unit.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT TO THE TESTIMONY

OF

PATRICK A. BOKOR

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2023 – DECEMBER 2023

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2023 - DECEMBER 2023
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2023 - DECEMBER 2023

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	17,848.9	8,924.4
+9	16,064.0	8,032.0
+8	14,279.1	7,139.6
+7	12,494.2	6,247.1
+6	10,709.3	5,354.7
+5	8,924.4	4,462.2
+4	7,139.6	3,569.8
+3	5,354.7	2,677.3
+2	3,569.8	1,784.9
+1	1,784.9	892.4
0	0.0	0.0
-1	(2,384.8)	(892.4)
-2	(4,769.7)	(1,784.9)
-3	(7,154.5)	(2,677.3)
-4	(9,539.3)	(3,569.8)
-5	(11,924.1)	(4,462.2)
-6	(14,309.0)	(5,354.7)
-7	(16,693.8)	(6,247.1)
-8	(19,078.6)	(7,139.6)
-9	(21,463.4)	(8,032.0)
-10	(23,848.3)	(8,924.4)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2023 - DECEMBER 2023

Line 1	Beginning of period balance of common equity: End of month common equity:		$	4,327,845,952	
Line 2	Month of January	2023	$	4,387,740,892	
Line 3	Month of February	2023	$	4,425,036,690	
Line 4	Month of March	2023	$	4,462,649,502	
Line 5	Month of April	2023	$	4,365,778,473	
Line 6	Month of May	2023	$	4,402,887,590	
Line 7	Month of June	2023	$	4,440,312,135	
Line 8	Month of July	2023	$	4,500,392,155	
Line 9	Month of August	2023	$	4,538,645,488	
Line 10	Month of September	2023	$	4,577,223,975	
Line 11	Month of October	2023	$	4,479,218,538	
Line 12	Month of November	2023	$	4,517,291,896	
Line 13	Month of December	2023	$	4,555,688,877	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	4,460,054,782	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			74.45%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	14,976,288	
Line 18	Jurisdictional Sales			19,953,481	MWH
Line 19	Total Sales			19,953,481	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)		$	14,976,288	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)		$	8,924,442	
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)		$	8,924,442	

Note: Line 22 and 23 are as approved by Commission order PSC-13-0665-FOF-EI dated 12/18/13 effective 1/1/14.

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2023 - DECEMBER 2023

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	5.66%	61.2	66.1	51.4	1,009.8	(3,719.4)
POLK 2	7.87%	90.9	92.1	88.4	1,404.2	(699.6)
BAYSIDE 1	5.94%	90.0	91.2	87.6	1,059.4	(1,412.7)
BAYSIDE 2	1.13%	75.2	76.9	71.7	202.1	(3,843.1)
GPIF SYSTEM	**20.59%**					

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	26.52%	10,777	67.0	10,058	11,497	4,734.2	(4,734.2)
POLK 2	28.52%	7,279	46.5	7,088	7,470	5,090.3	(5,090.3)
BAYSIDE 1	14.60%	7,481	43.7	7,307	7,655	2,605.9	(2,605.9)
BAYSIDE 2	9.76%	8,280	19.9	7,977	8,582	1,742.9	(1,742.9)
GPIF SYSTEM	**79.41%**						

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 23 - DEC 23 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 21 - DEC 21 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 20 - DEC 20 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 19 - DEC 19 POF	EUOF	EUOR
BIG BEND 4	5.66%	27.5%	18.9	19.9	24.5	18.7	12.8	15.8	37.1	25.1	39.9	16.5	28.0	39.8
POLK 2	7.87%	38.2%	3.8	5.3	5.5	11.0	3.7	4.1	2.8	7.7	8.0	4.5	2.9	3.0
BAYSIDE 1	5.94%	28.8%	5.3	4.7	5.0	5.4	5.8	6.2	7.7	2.9	3.1	11.1	3.7	4.1
BAYSIDE 2	1.13%	5.5%	21.8	3.1	4.0	5.5	1.9	2.0	4.3	5.0	5.2	11.4	3.2	3.6
GPIF SYSTEM	**20.59%**	**100.0%**	**9.4**	**9.0**	**10.5**	**11.2**	**6.7**	**7.8**	**13.7**	**10.9**	**15.2**	**10.1**	**10.0**	**13.5**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**81.6**			**82.1**			**75.3**			**79.9**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
11.7	**9.2**	**12.2**	**79.1**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 23 - DEC 23	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 21 - DEC 21	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 20 - DEC 20	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 19 - DEC 19
BIG BEND 4	26.52%	33.4%	10,777	10,630	10,785	10,876
POLK 2	28.52%	35.9%	7,279	7,279	7,197	7,427
BAYSIDE 1	14.60%	18.4%	7,481	7,484	7,467	7,462
BAYSIDE 2	9.76%	12.3%	8,280	8,232	8,212	8,326
GPIF SYSTEM	**79.41%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**8,608**	**8,553**	**8,570**	**8,696**

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TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2023 - DECEMBER 2023
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	831,414.63	830,404.81	1,009.82	5.66%
EA_2 POLK 2	831,414.63	830,010.39	1,404.24	7.87%
EA_3 BAYSIDE 1	831,414.63	830,355.26	1,059.37	5.94%
EA_4 BAYSIDE 2	831,414.63	831,212.51	202.12	1.13%
AVERAGE HEAT RATE				
AHR_3 BIG BEND 4	831,414.63	826,680.40	4,734.23	26.52%
AHR_2 POLK 2	831,414.63	826,324.32	5,090.31	28.52%
AHR_3 BAYSIDE 1	831,414.63	828,808.75	2,605.88	14.60%
AHR_4 BAYSIDE 2	831,414.63	829,671.72	1,742.91	9.76%
TOTAL SAVINGS			**17,848.88**	**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 2023 - DECEMBER 2023

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	1,009.8	66.1	+10	4,734.2	10,058
+9	908.8	65.6	+9	4,260.8	10,122
+8	807.9	65.1	+8	3,787.4	10,186
+7	706.9	64.6	+7	3,314.0	10,251
+6	605.9	64.2	+6	2,840.5	10,315
+5	504.9	63.7	+5	2,367.1	10,380
+4	403.9	63.2	+4	1,893.7	10,444
+3	302.9	62.7	+3	1,420.3	10,509
+2	202.0	62.2	+2	946.8	10,573
+1	101.0	61.7	+1	473.4	10,638
					10,702
0	0.0	61.2	0	0.0	10,777
					10,852
-1	(371.9)	60.2	-1	(473.4)	10,917
-2	(743.9)	59.2	-2	(946.8)	10,981
-3	(1,115.8)	58.2	-3	(1,420.3)	11,046
-4	(1,487.8)	57.3	-4	(1,893.7)	11,110
-5	(1,859.7)	56.3	-5	(2,367.1)	11,175
-6	(2,231.7)	55.3	-6	(2,840.5)	11,239
-7	(2,603.6)	54.3	-7	(3,314.0)	11,303
-8	(2,975.6)	53.3	-8	(3,787.4)	11,368
-9	(3,347.5)	52.3	-9	(4,260.8)	11,432
-10	(3,719.4)	51.4	-10	(4,734.2)	11,497
	Weighting Factor =	5.66%		Weighting Factor =	26.52%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2023 - DECEMBER 2023

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	1,404.2	92.1	+10	5,090.3	7,088
+9	1,263.8	92.0	+9	4,581.3	7,100
+8	1,123.4	91.9	+8	4,072.3	7,111
+7	983.0	91.8	+7	3,563.2	7,123
+6	842.5	91.6	+6	3,054.2	7,134
+5	702.1	91.5	+5	2,545.2	7,146
+4	561.7	91.4	+4	2,036.1	7,158
+3	421.3	91.3	+3	1,527.1	7,169
+2	280.8	91.1	+2	1,018.1	7,181
+1	140.4	91.0	+1	509.0	7,193
					7,204
0	0.0	90.9	0	0.0	7,279
					7,354
-1	(70.0)	90.6	-1	(509.0)	7,366
-2	(139.9)	90.4	-2	(1,018.1)	7,377
-3	(209.9)	90.1	-3	(1,527.1)	7,389
-4	(279.8)	89.9	-4	(2,036.1)	7,401
-5	(349.8)	89.6	-5	(2,545.2)	7,412
-6	(419.8)	89.4	-6	(3,054.2)	7,424
-7	(489.7)	89.1	-7	(3,563.2)	7,436
-8	(559.7)	88.9	-8	(4,072.3)	7,447
-9	(629.7)	88.6	-9	(4,581.3)	7,459
-10	(699.6)	88.4	-10	(5,090.3)	7,470
	Weighting Factor =	7.87%		Weighting Factor =	28.52%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2023 - DECEMBER 2023

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	1,059.4	91.2	+10	2,605.9	7,307
+9	953.4	91.1	+9	2,345.3	7,316
+8	847.5	91.0	+8	2,084.7	7,326
+7	741.6	90.9	+7	1,824.1	7,336
+6	635.6	90.7	+6	1,563.5	7,346
+5	529.7	90.6	+5	1,302.9	7,356
+4	423.7	90.5	+4	1,042.4	7,366
+3	317.8	90.4	+3	781.8	7,376
+2	211.9	90.3	+2	521.2	7,386
+1	105.9	90.1	+1	260.6	7,396
					7,406
0	0.0	90.0	0	0.0	7,481
					7,556
-1	(141.3)	89.8	-1	(260.6)	7,566
-2	(282.5)	89.5	-2	(521.2)	7,576
-3	(423.8)	89.3	-3	(781.8)	7,586
-4	(565.1)	89.1	-4	(1,042.4)	7,596
-5	(706.4)	88.8	-5	(1,302.9)	7,606
-6	(847.6)	88.6	-6	(1,563.5)	7,616
-7	(988.9)	88.3	-7	(1,824.1)	7,626
-8	(1,130.2)	88.1	-8	(2,084.7)	7,636
-9	(1,271.5)	87.9	-9	(2,345.3)	7,645
-10	(1,412.7)	87.6	-10	(2,605.9)	7,655
	Weighting Factor =	5.94%		Weighting Factor =	14.60%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2023 - DECEMBER 2023

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	202.1	76.9	+10	1,742.9	7,977
+9	181.9	76.7	+9	1,568.6	8,000
+8	161.7	76.5	+8	1,394.3	8,023
+7	141.5	76.3	+7	1,220.0	8,046
+6	121.3	76.2	+6	1,045.7	8,068
+5	101.1	76.0	+5	871.5	8,091
+4	80.8	75.8	+4	697.2	8,114
+3	60.6	75.7	+3	522.9	8,137
+2	40.4	75.5	+2	348.6	8,159
+1	20.2	75.3	+1	174.3	8,182
					8,205
0	0.0	75.2	0	0.0	8,280
					8,355
-1	(384.3)	74.8	-1	(174.3)	8,378
-2	(768.6)	74.5	-2	(348.6)	8,400
-3	(1,152.9)	74.1	-3	(522.9)	8,423
-4	(1,537.2)	73.8	-4	(697.2)	8,446
-5	(1,921.6)	73.4	-5	(871.5)	8,469
-6	(2,305.9)	73.1	-6	(1,045.7)	8,491
-7	(2,690.2)	72.8	-7	(1,220.0)	8,514
-8	(3,074.5)	72.4	-8	(1,394.3)	8,537
-9	(3,458.8)	72.1	-9	(1,568.6)	8,560
-10	(3,843.1)	71.7	-10	(1,742.9)	8,582
	Weighting Factor =	1.13%		Weighting Factor =	9.76%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2023 - DECEMBER 2023

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-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	2023
1. EAF (%)	75.5	75.5	75.5	0.0	14.6	75.5	75.5	75.5	75.5	75.5	40.2	75.5	61.2
2. POF	0.0	0.0	0.0	100.0	80.6	0.0	0.0	0.0	0.0	0.0	46.7	0.0	18.9
3. EUOF	24.5	24.5	24.5	0.0	4.7	24.5	24.5	24.5	24.5	24.5	13.1	24.5	19.9
4. EUOR	24.5	24.5	24.5	0.0	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	637	467	607	0	56	488	382	663	490	670	202	293	4,955
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	107	205	137	720	688	232	362	81	230	74	518	451	3,805
9. POH	0	0	0	720	600	0	0	0	0	0	336	0	1,656
10. EFOH	110	99	110	0	21	106	110	110	106	110	57	110	1,049
11. EMOH	73	66	73	0	14	70	73	73	70	73	38	73	695
12. OPER BTU (GBTU)	2,372	1,788	1,999	0	150	1,334	1,055	1,826	1,406	1,883	550	808	15,223
13. NET GEN (MWH)	228,660	173,570	187,410	0	13,600	121,530	96,300	166,550	129,110	172,230	50,100	73,440	1,412,500
14. ANOHR (Btu/kwh)	10,373	10,299	10,665	12,463	11,015	10,979	10,960	10,966	10,893	10,931	10,985	11,004	10,777
15. NOF (%)	83.1	86.0	71.5	0.0	57.5	59.0	59.7	59.5	62.4	60.9	58.8	58.0	67.0
16. NPC (MW)	432	432	432	422	422	422	422	422	422	422	422	432	425

17. ANOHR EQUATION ANOHR = NOF(-25.146) + 12,463

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2023 - DECEMBER 2023

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-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	2023
1. EAF (%)	94.5	94.5	74.7	91.3	94.5	94.5	94.5	94.5	94.5	94.5	87.9	81.4	90.9
2. POF	0.0	0.0	21.0	3.3	0.0	0.0	0.0	0.0	0.0	0.0	7.0	13.9	3.8
3. EUOF	5.5	5.5	4.4	5.3	5.5	5.5	5.5	5.5	5.5	5.5	5.1	4.7	5.3
4. EUOR	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	637	556	536	690	725	700	718	721	705	727	702	590	8,007
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	107	116	208	30	19	20	26	23	15	17	18	154	753
9. POH	0	0	156	24	0	0	0	0	0	0	50	103	334
10. EFOH	21	19	16	19	21	20	21	21	20	21	18	18	232
11. EMOH	21	19	16	19	21	20	21	21	20	21	18	18	232
12. OPER BTU (GBTU)	1,390	1,265	1,232	2,296	2,970	3,212	3,457	3,518	3,479	2,975	2,238	1,763	30,000
13. NET GEN (MWH)	185,540	169,170	164,760	313,930	411,800	449,400	485,790	495,090	490,010	412,410	305,260	238,250	4,121,410
14. ANOHR (Btu/kwh)	7,490	7,480	7,477	7,313	7,212	7,146	7,115	7,106	7,099	7,213	7,331	7,401	7,279
15. NOF (%)	24.3	25.4	25.6	42.9	53.5	60.5	63.8	64.7	65.5	53.5	41.0	33.7	46.5
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(-9.479) + 7,720

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2023 - DECEMBER 2023

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-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	2023
1. EAF (%)	95.0	95.0	94.4	78.9	95.0	95.0	95.0	95.0	95.0	95.0	82.4	64.4	90.0
2. POF	0.0	0.0	0.6	17.0	0.0	0.0	0.0	0.0	0.0	0.0	13.3	32.3	5.3
3. EUOF	5.0	5.0	4.9	4.1	5.0	5.0	5.0	5.0	5.0	5.0	4.3	3.4	4.7
4. EUOR	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	707	639	703	568	707	684	707	707	684	707	593	479	7,884
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	37	33	41	152	37	36	37	37	36	37	127	265	875
9. POH	0	0	5	122	0	0	0	0	0	0	96	240	463
10. EFOH	17	15	17	14	17	16	17	17	16	17	14	11	188
11. EMOH	20	18	20	16	20	19	20	20	19	20	17	14	223
12. OPER BTU (GBTU)	1,015	879	1,506	1,353	1,798	2,002	2,214	2,137	2,158	1,745	1,006	986	18,840
13. NET GEN (MWH)	134,370	116,290	200,520	181,040	240,940	269,370	298,520	287,730	291,010	233,640	133,730	131,220	2,518,380
14. ANOHR (Btu/kwh)	7,556	7,560	7,510	7,474	7,462	7,433	7,418	7,426	7,416	7,468	7,525	7,516	7,481
15. NOF (%)	24.0	23.0	36.0	45.5	48.6	56.2	60.2	58.1	60.7	47.1	32.2	34.6	43.7
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731

17. ANOHR EQUATION ANOHR = NOF(-3.808) + 7,647

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2023 - DECEMBER 2023

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-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	2023
1. EAF (%)	96.0	96.0	96.0	91.2	84.0	96.0	96.0	96.0	22.4	0.0	32.0	96.0	75.2
2. POF	0.0	0.0	0.0	5.0	12.6	0.0	0.0	0.0	76.7	100.0	66.7	0.0	21.8
3. EUOF	4.0	4.0	4.0	3.8	3.5	4.0	4.0	4.0	0.9	0.0	1.3	4.0	3.1
4. EUOR	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	0.0	4.0	4.0	4.0
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	715	645	715	657	625	692	715	715	161	0	231	715	6,583
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	29	27	29	63	119	28	29	29	559	744	489	29	2,176
9. POH	0	0	0	36	94	0	0	0	552	744	480	0	1,906
10. EFOH	5	5	5	5	5	5	5	5	1	0	2	5	50
11. EMOH	24	22	24	22	21	23	24	24	5	0	8	24	221
12. OPER BTU (GBTU)	939	807	1,108	968	1,146	1,141	1,403	1,386	261	0	313	1,024	10,513
13. NET GEN (MWH)	111,990	96,090	133,080	116,610	139,870	138,340	172,060	169,790	31,680	0	37,610	122,610	1,269,730
14. ANOHR (Btu/kwh)	8,384	8,400	8,325	8,297	8,192	8,246	8,154	8,161	8,253	0	8,330	8,354	8,280
15. NOF (%)	15.0	14.2	17.8	19.1	24.1	21.5	25.9	25.6	21.2	0.0	17.6	16.4	19.9
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(-21.057) + 8,699

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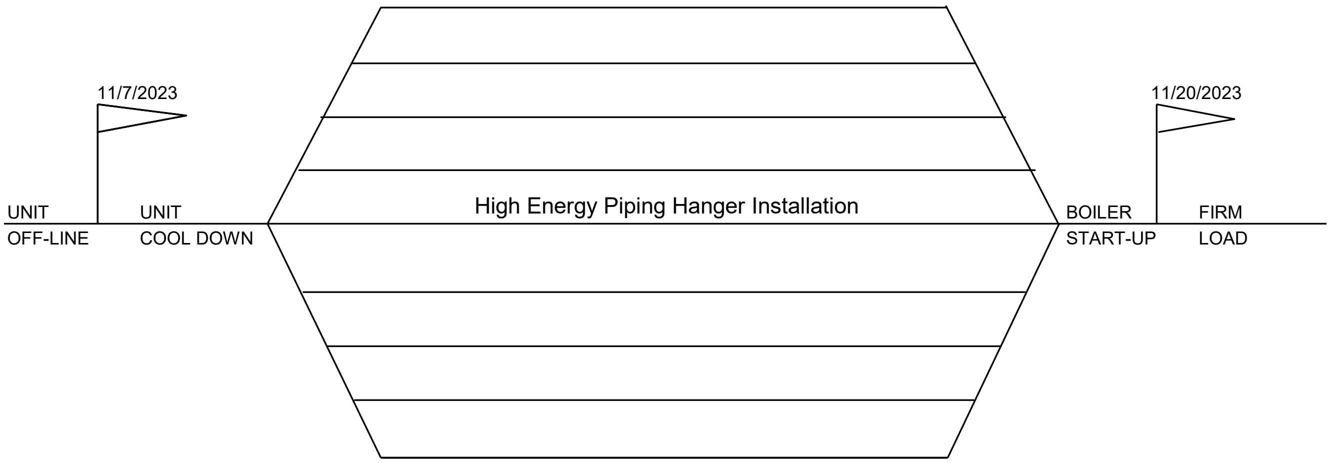
TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2023 - DECEMBER 2023

	PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
+	BIG BEND 4	Apr 01 - May 25	Waterwall, Penthouse headers, Pipe Hangers
		Nov 07 - Nov 20	Cleanup Outage
	POLK 2	Mar 06 - Mar 10	Combined Cycle Planned Outage
		Dec 11 - Dec 15	Combined Cycle Planned Outage
	BAYSIDE 1	Nov 27 - Dec 10	Combined Cycle Planned Outage
+	BAYSIDE 2	Sep 08 - Nov 20	CT 2A Major and AGP upgrade
			CT 2B Major and AGP upgrade
			CT 2C Major and AGP upgrade
			CT 2C Major and AGP upgrade
			Mark Vie DCS and LCI Upgrades
			Steam Turbine valve overhauls
			Unit 2 CW Inlet structural refurbishment
			CW Tunnel liner replacement
			Steam Turbine 2 Exciter replacement

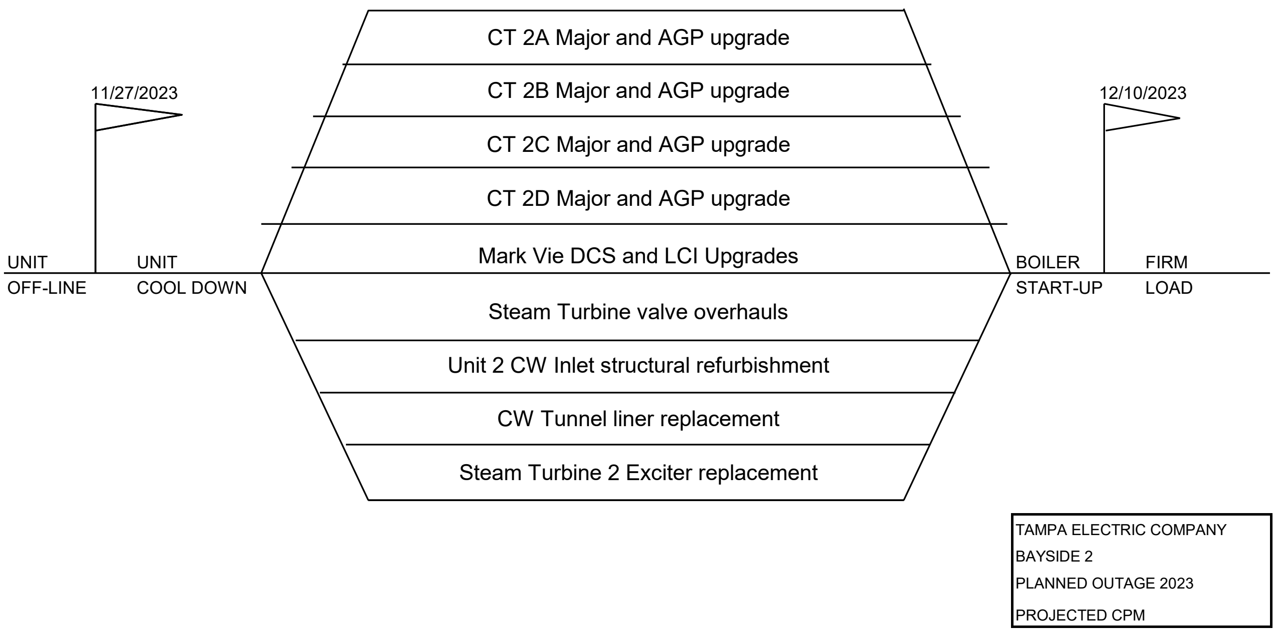
+ These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.

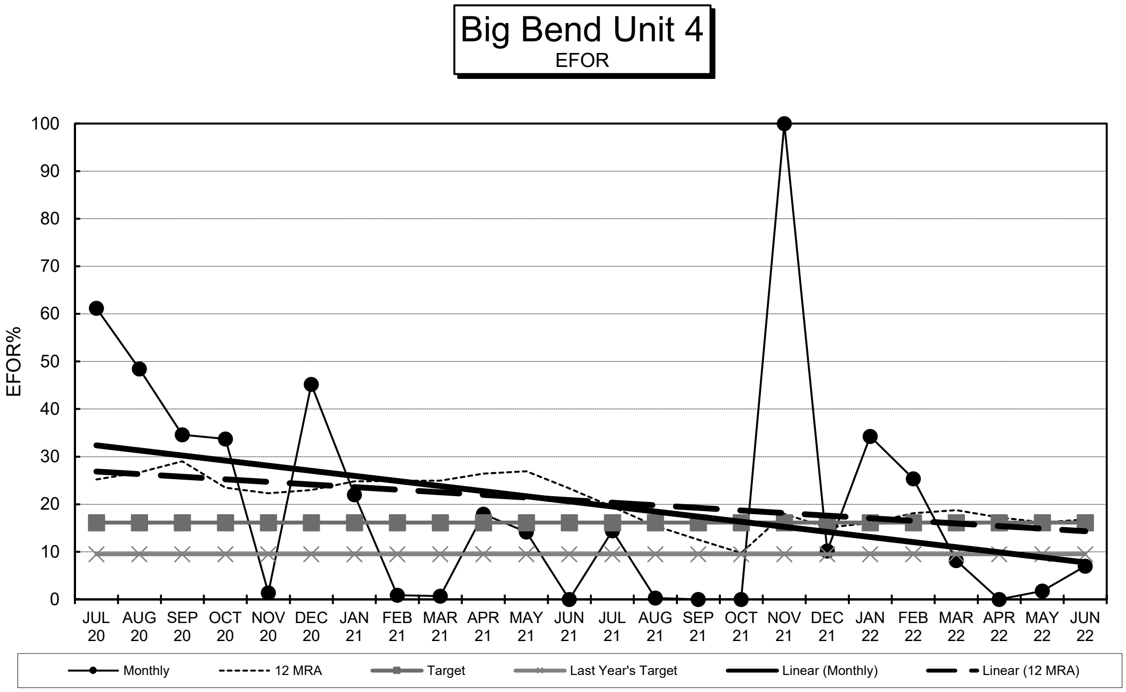
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2023 - DECEMBER 2023



TAMPA ELECTRIC COMPANY
BIG BEND 4
PLANNED OUTAGE 2023
PROJECTED CPM

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2023 - DECEMBER 2023




Big Bend Unit 4
EFOR
EFOR%
100
90
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70
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JUL 20
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OCT 20
NOV 20
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AUG 21
SEP 21
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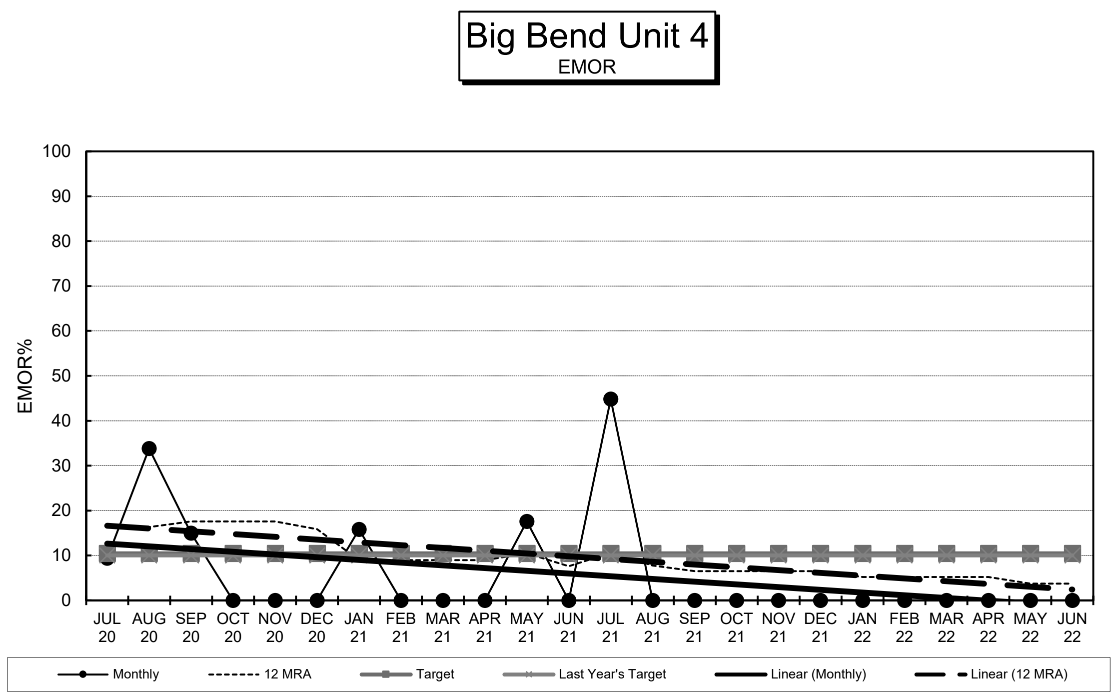
NOV 21
DEC 21
JAN 22
FEB 22
MAR 22
APR 22
MAY 22
JUN 22
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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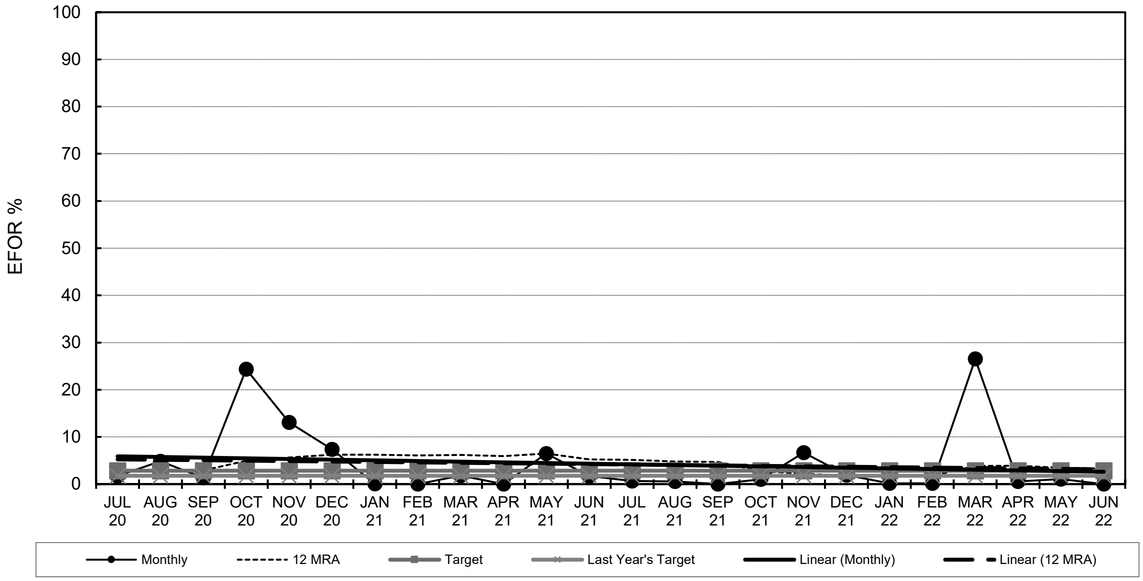
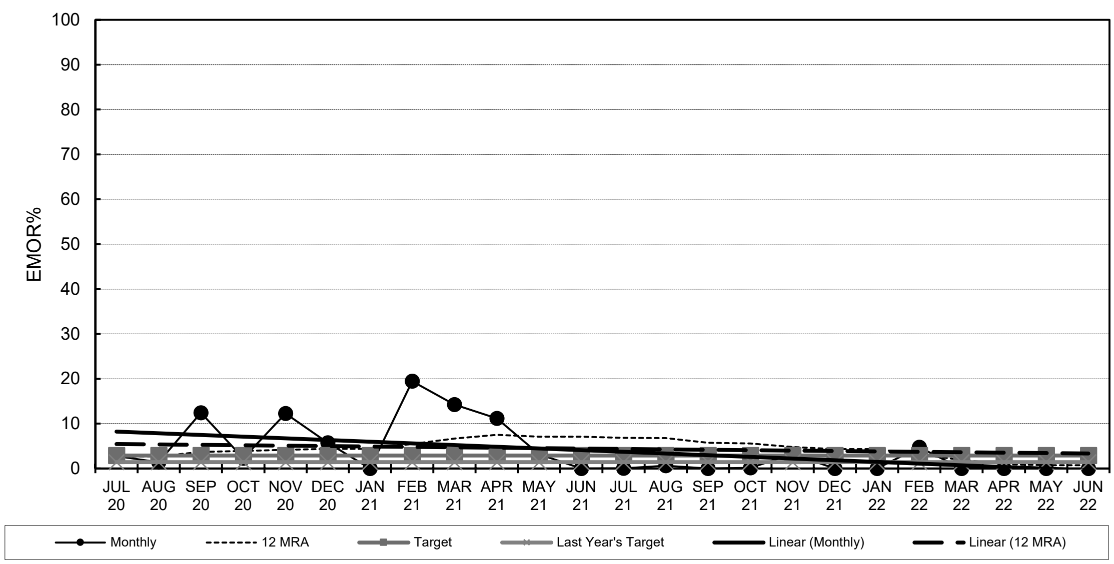
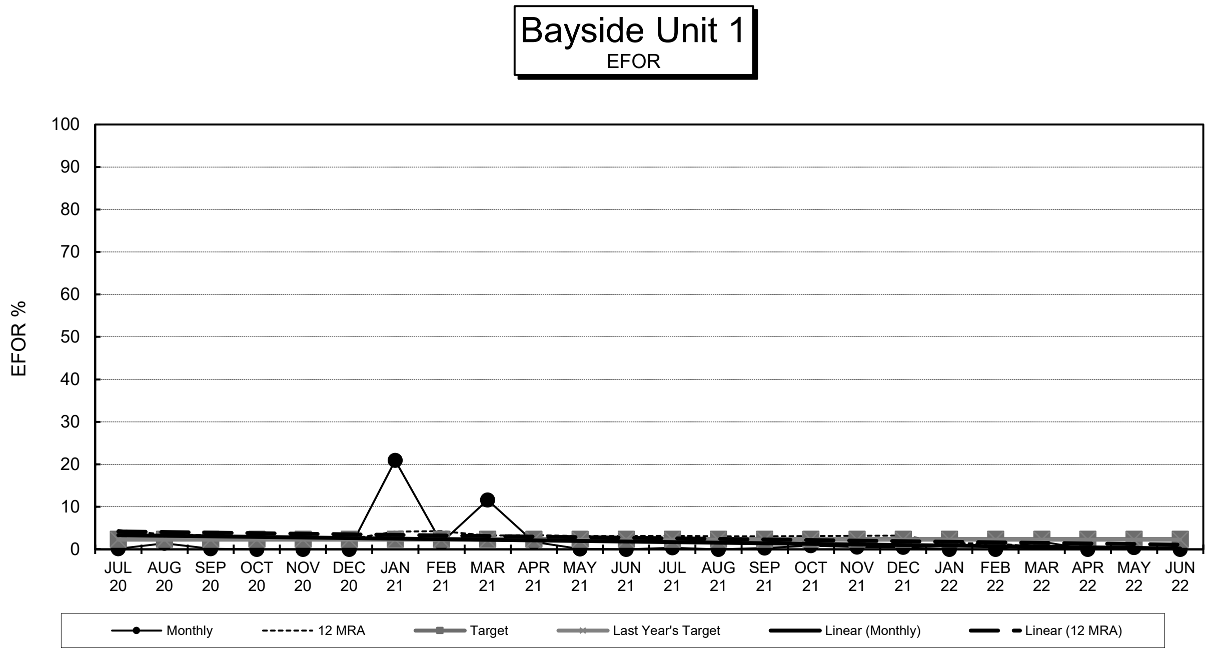
MAR 22
APR 22
MAY 22
JUN 22
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

Polk Unit 2
EFOR



Polk Unit 2
EMOR




Bayside Unit 1
EFOR
EFOR %
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JUL 20
AUG 20
SEP 20
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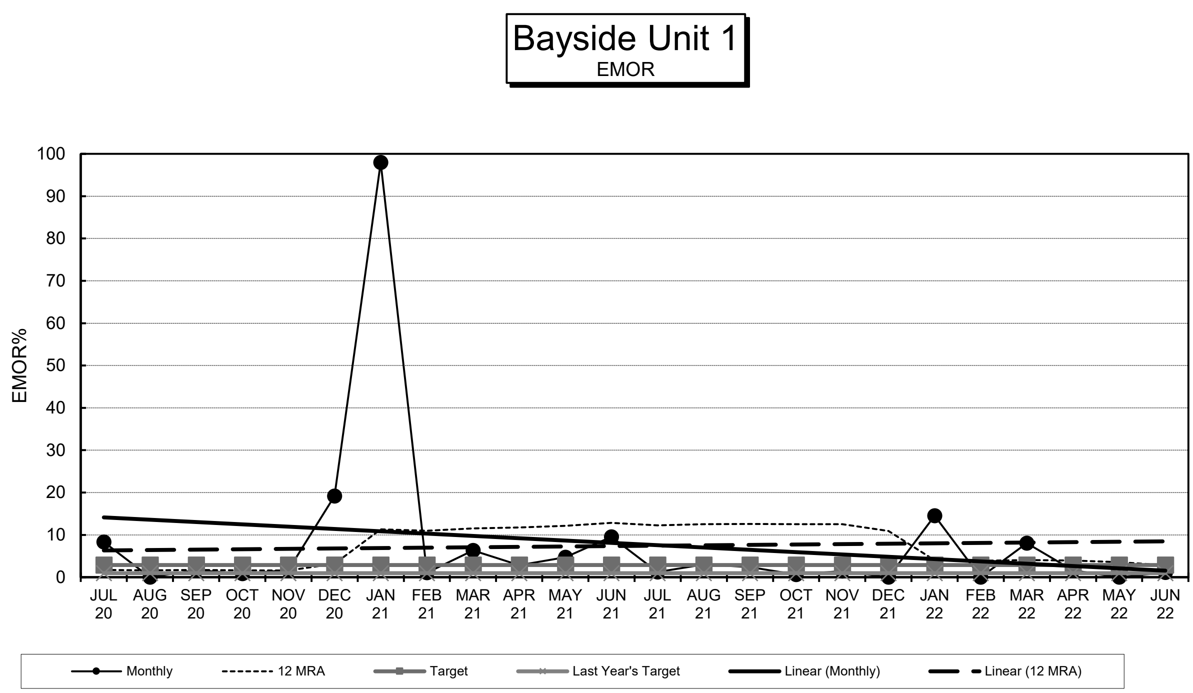
MAY 22
JUN 22
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EMOR%
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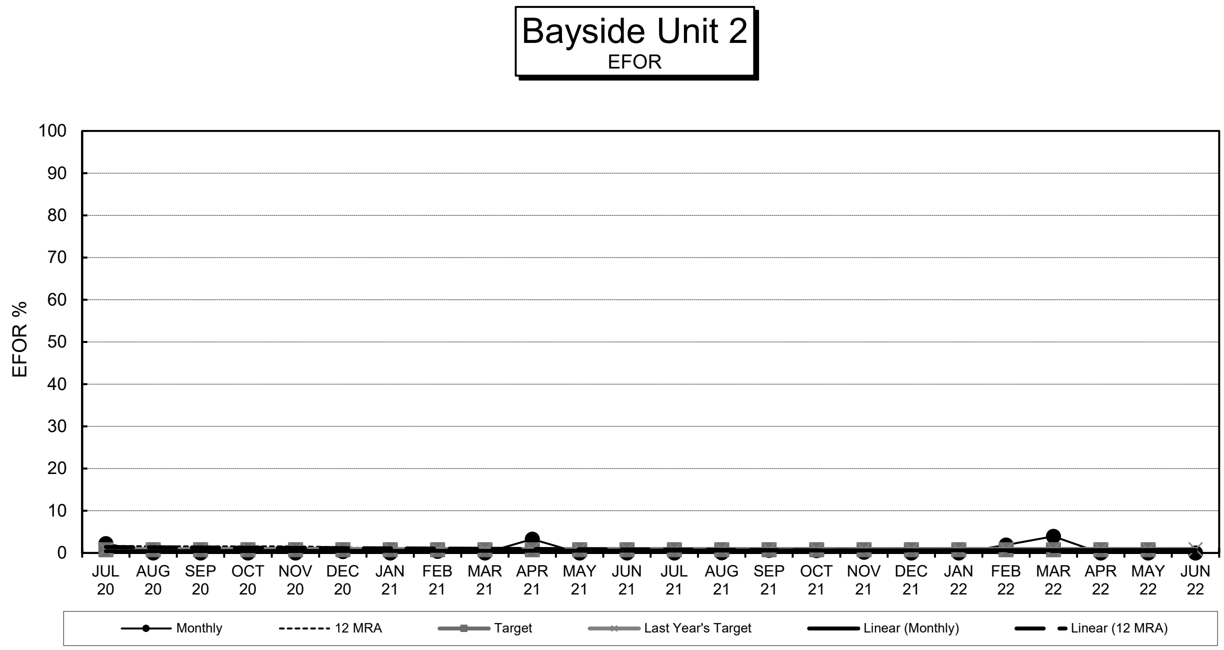
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EFOR
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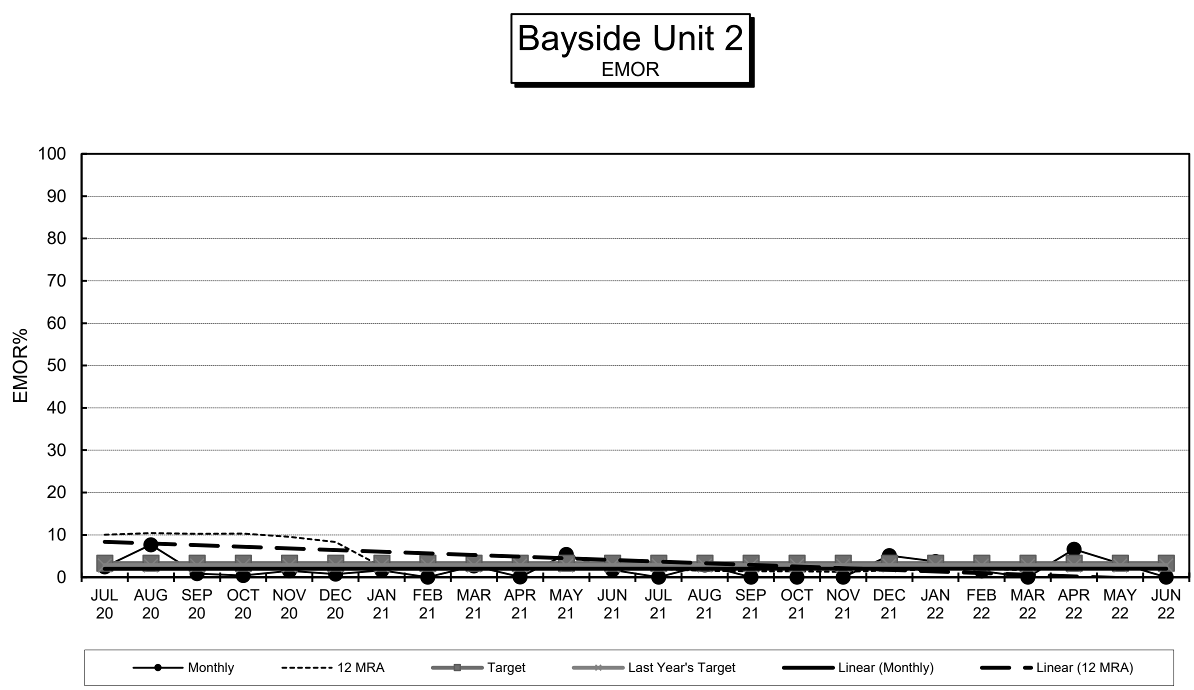
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EMOR
EMOR%
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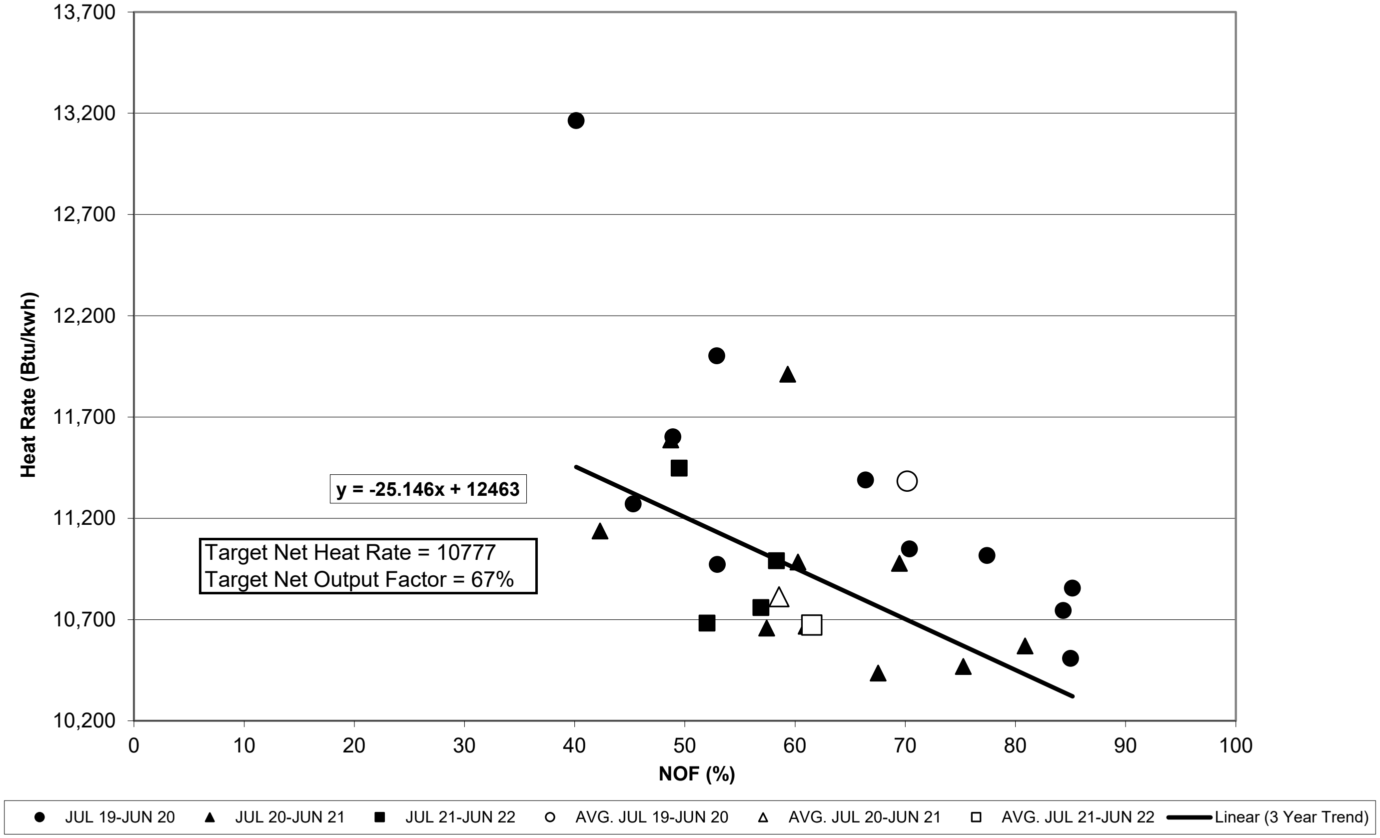
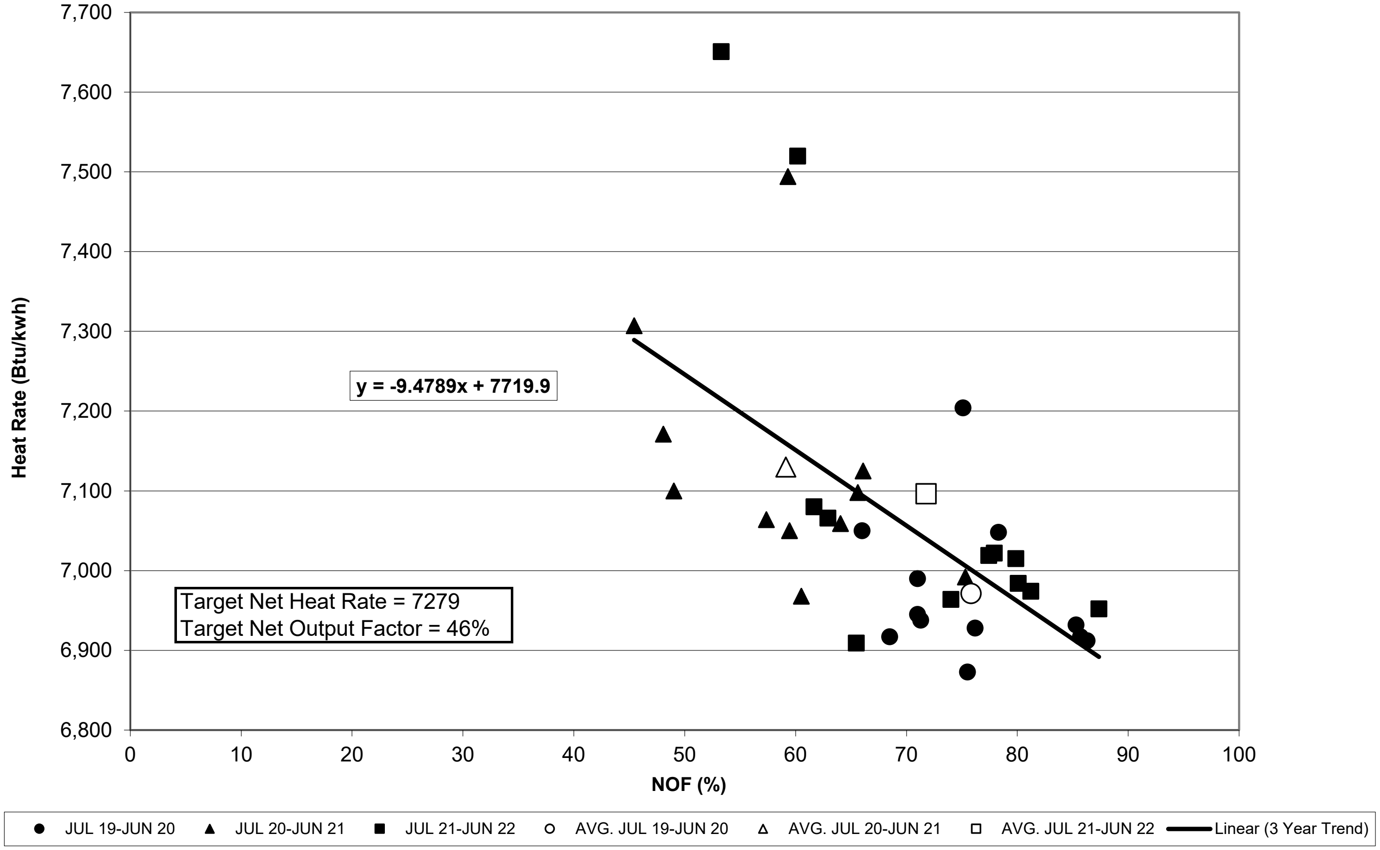
MAY 22
JUN 22
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4



Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 2



Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1

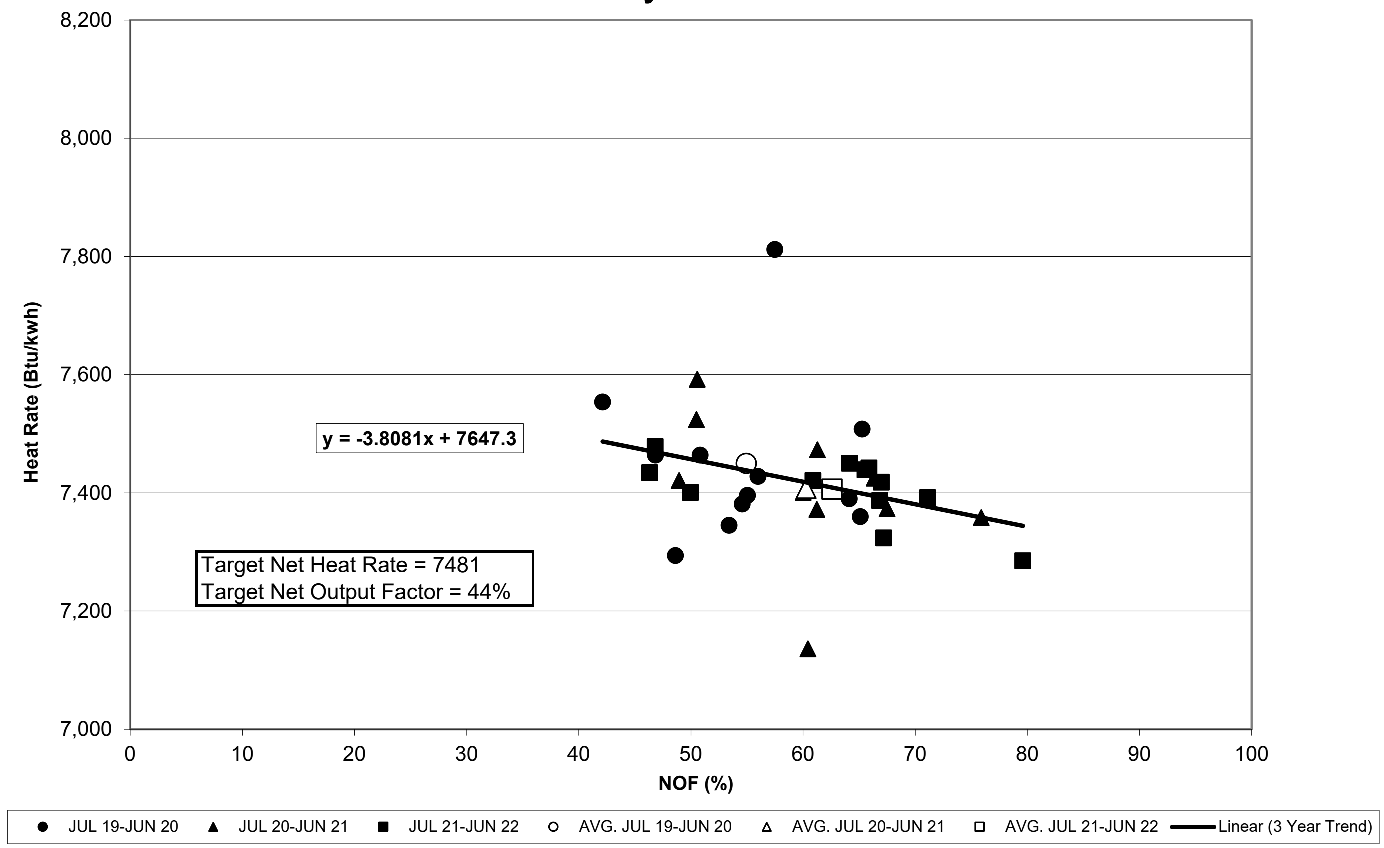


EXHIBIT NO.______ (PAB-2)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20220001-EI
DOCUMENT NO. 1
PAGE 24 OF 28

Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2

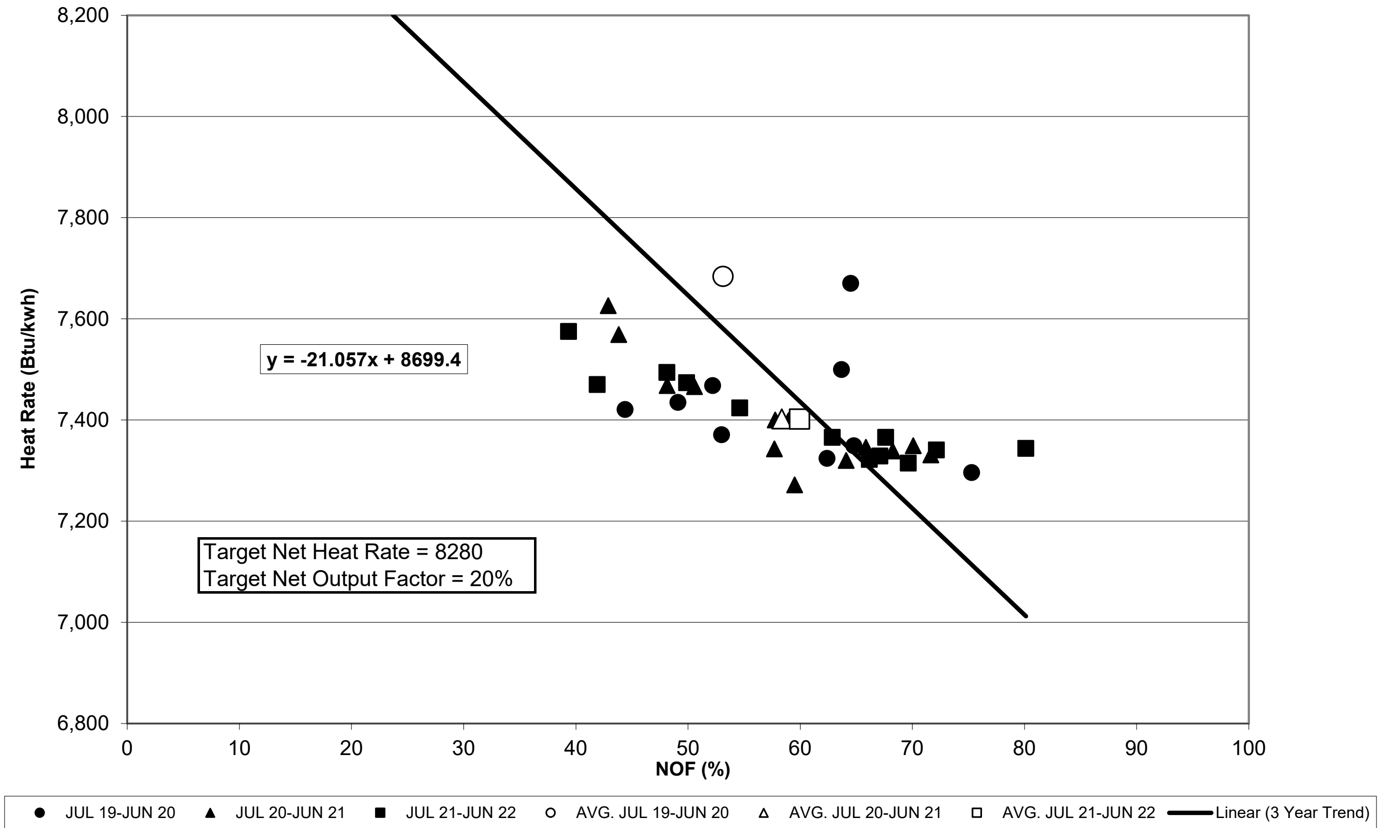


EXHIBIT NO._____ (PAB-2)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20220001-EI
DOCUMENT NO. 1
PAGE 25 OF 28

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2023 - DECEMBER 2023

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 4		458	425
POLK 2		1,130	1,107
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,308	3,232
	SYSTEM TOTAL	**6,386**	**6,243**
	% OF SYSTEM TOTAL	**51.8%**	**51.8%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2023 - DECEMBER 2023

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		1,101	1,076
BIG BEND 3		368	348
BIG BEND 4		458	425
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,987	1,908
POLK 1		225	210
POLK 2		1,130	1,107
	POLK TOTAL	1,355	1,317
SOLAR		1,091	1,087
	SOLAR TOTAL	1,091	1,087
	SYSTEM TOTAL	**6,386**	**6,243**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2023 - DECEMBER 2023

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BIG BEND	1 (new CC without history)	8,708,240	41.60%	41.60%
POLK	2	4,121,410	19.69%	61.28%
BAYSIDE	1	2,518,380	12.03%	73.31%
SOLAR		2,355,720	11.25%	84.56%
BIG BEND	4	1,412,500	6.75%	91.31%
BAYSIDE	2	1,269,730	6.06%	97.37%
POLK	1	437,640	2.09%	99.46%
BIG BEND	3	50,320	0.24%	99.71%
BAYSIDE	6	13,000	0.06%	99.77%
BAYSIDE	5	12,440	0.06%	99.83%
BAYSIDE	3	12,380	0.06%	99.89%
BIG BEND CT	4	12,260	0.06%	99.94%
BAYSIDE	4	11,660	0.06%	100.00%
TOTAL GENERATION		20,935,680	100.00%	

GENERATION BY COAL UNITS:	1,412,500	MWH	GENERATION BY NATURAL GAS UNITS:	17,167,460	MWH
% GENERATION BY COAL UNITS	6.75%		% GENERATION BY NATURAL GAS UNITS:	82.00%	
GENERATION BY SOLAR UNITS:	2,355,720	MWH	GENERATION BY GPIF UNITS:	9,322,020	MWH
% GENERATION BY SOLAR UNIT	11.25%		% GENERATION BY GPIF UNITS:	44.53%	

EXHIBIT TO THE TESTIMONY

OF

PATRICK A. BOKOR

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2023 – DECEMBER 2023

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2023 - DECEMBER 2023

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend 4[1]	61.2	18.9	19.9	10,777
Polk 2[2]	90.9	3.8	5.3	7,279
Bayside 1[3]	90.0	5.3	4.7	7,481
Bayside 2[4]	75.2	21.8	3.1	8,280

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

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY
OF
JOHN C. HEISEY

FILED: SEPTEMBER 2, 2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

Q. Please state your name, address, occupation, and employer.

A. My name is John C. Heisey. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Origination and Trading.

Q. Have you previously filed testimony in Docket No. 20220001-EI?

A. Yes, I submitted direct testimony on April 1, 2022 and July 27, 2022.

Q. Has your job description, education, or professional experience changed since your most recent testimony?

A. No, they have not.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for directing all activities associated with the procurement and delivery of energy commodities for Tampa Electric’s generation fleet. Such activities include the trading, optimization, strategy, planning, origination, compliance and regulatory oversight of natural gas, power, coal, oil, byproducts, and associated delivery. I am also responsible for all aspects of the Optimization Mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Tampa Electric’s fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company’s fuel procurement strategies.

Fuel Mix and Procurement Strategies

Q. What fuels do Tampa Electric’s generating stations use?

A. Tampa Electric’s generation portfolio includes natural gas, solar, coal, and, as a backup fuel, oil powered units. Big Bend Unit 3 operates on natural gas, and Big Bend Unit 4 can operate on coal or natural gas. Big Bend Modernization project’s first phase, Big Bend combustion turbine Units 5 and 6, operate on natural gas. The second phase of the Big Bend Modernization project includes the addition of the Heat Recovery Steam Generator (“HRSG”) in December 2022 and will result in the unit’s operation in combined cycle mode. Polk Unit 1 can operate on natural gas or a blend of petroleum coke and coal. Currently, the company is operating Polk Unit 1 on natural gas and Big Bend Unit 4 on coal. Polk Unit 2 combined cycle uses natural gas as a primary fuel and oil as a secondary fuel; and Bayside Station combined cycle units and the company’s collection of peakers (*i.e.,* aero-derivative combustion turbines) all utilize natural gas. Since it serves as a backup fuel, oil consumption is primarily for testing, and oil is a negligible percentage of system generation. Based upon the 2022 actual-estimate projections, the company expects 2022 total system generation, excluding purchased power, to be 85 percent natural gas, 9 percent solar, and 6 percent coal.

Likewise, in 2023, natural gas-fired and solar generation are expected to be 84 percent and 11 percent of total generation, respectively, with coal-fired generation making up 5 percent of total generation.

Q. Please describe Tampa Electric’s fuel supply procurement strategy.

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all its fuel needs. The company strives to maintain many creditworthy and viable suppliers. Similarly, the company endeavors to maintain multiple delivery path options. Tampa Electric also attempts to diversify the locations from which its supply is sourced. Having a greater number of fuel supply and delivery options provides increased reliability and flexibility to pursue lower cost options for Tampa Electric customers.

Natural Gas Supply Strategy

Q. How does Tampa Electric's natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long- and short-term deliveries?

A. Tampa Electric uses a portfolio approach to natural gas procurement. This approach consists of a blend of pre-arranged base, intermediate, and swing natural gas supply contracts complemented with shorter term spot and seasonal purchases. The contracts have various time lengths to help secure needed supply at competitive prices while maintaining the flexibility to adapt to any changing fuel needs. Tampa Electric purchases its physical natural gas supply from creditworthy counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. Tampa Electric targets natural gas supply that is reliable and resistant to the impacts of extreme weather. The natural gas prices are based on monthly and daily price indices, further increasing pricing diversification.

Tampa Electric diversifies its pipeline transportation assets, including receipt points. The company also utilizes pipeline and storage services to enhance access to natural gas supply during hurricanes, extreme weather or other events that constrain supply. Such actions improve the reliability and cost-effectiveness of the physical delivery of natural gas to the company's power plants. Furthermore, Tampa Electric strives daily to obtain reliable supplies of natural gas at favorable prices to mitigate costs for its customers.

Q. Please describe Tampa Electric's diversified natural gas transportation agreements.

A. Tampa Electric currently receives natural gas directly via the Florida Gas Transmission ("FGT") and Gulfstream

Natural Gas System, LLC ("Gulfstream") pipelines. Tampa Electric also receives a portion of its gas via the recently constructed Sabal Trail Transmission ("Sabal Trail") gas pipeline (via Gulfstream backhaul). The ability to deliver natural gas from three pipelines increases the fuel delivery reliability for Bayside Power Station, which is composed of two large natural gas combined-cycle units and four aero-derivative combustion turbines. Natural gas can also be delivered to Big Bend Station from Gulfstream and Sabal Trail to support the station's steam generating units, aero-derivative combustion turbine, and upcoming Big Bend Modernization project. Later this year, the second and final phase of a new gas pipeline lateral will be completed that allows natural gas to be delivered to the Big Bend Station from FGT. This lateral increases the fuel delivery reliability for Big Bend Station. Polk Station receives natural gas from FGT to support natural gas consumption in Polk Units 1 and 2.

Q. Are there any significant changes to Tampa Electric's expected natural gas usage?

A. Tampa Electric's natural gas usage is expected to slightly decrease in 2023 when compared to 2022. Additional solar generation, the retirement of Big Bend Unit 3, and the combined cycle operation at the efficient Big Bend Modernization project will result in a reduction in natural gas usage in the period.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric maintains natural gas storage capacity with Bay Gas Storage near Mobile, Alabama, and Southern Pines Energy Center in Eastern Mississippi to provide operational flexibility and reliability of natural gas supply. The company reserves 2,000,000 MMBtu of long-term storage capacity in these two locations. This storage was used during Storm Uri in February 2021 to replace interrupted supply and to mitigate costs for our customers. Storage was also utilized this summer to help mitigate the risk of southeast gas basis premiums.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT Zones 1, 2, and 3. Diverse receipt points reduce the company's vulnerability to hurricane impacts and provide access to potentially lower priced gas supply.

Tampa Electric also reserves capacity on the Southeast Supply Header ("SESH"), Gulf South pipeline ("Gulf South"), and Transco's Mobile Bay Lateral ("Transco"). SESH, Gulf South, and Transco connect the receipt points of FGT, Gulfstream, and other Mobile Bay area pipelines with natural gas supply in the mid-continent and northeast. Mid-continent and northeast natural gas production, specifically shale production, has grown and continues to increase. Thus, SESH, Gulf South, and Transco capacity give Tampa Electric access to secure, competitively priced onshore gas supply for a portion of its portfolio. Tampa Electric continuously evaluates its gas transportation portfolio based on changing market conditions to ensure access to reliable natural gas supply. All receipt points in the portfolio are reviewed annually to ensure access to reliable supply basins.

Q. Has Tampa Electric acquired additional natural gas transportation for 2022 and 2023 due to greater use of natural gas?

A. Yes. In 2022, Tampa Electric acquired short-term capacity on FGT in January and February to increase the reliability of the portfolio for its projected winter peak. In addition, power purchases were executed for January and

February as a lower cost solution compared to acquiring additional short-term pipeline capacity, as mentioned in the testimony of Tampa Electric witness Benjamin F. Smith, II. In the summer of 2022, Tampa Electric acquired additional short-term pipeline capacity on FGT. This capacity provides additional transportation for the portfolio to support higher gas burns over the summer as well as increasing the reliability of the portfolio for its projected winter peak in 2023. At the end of 2022, Tampa Electric will replace its Sabal Trail capacity with Gulfstream capacity to supply the Big Bend Modernization project and other portfolio gas requirements. For 2023, Tampa Electric has acquired additional capacity on FGT. This capacity provides additional transportation for the portfolio as Tampa Electric continues to transition from coal-fired generation to cleaner burning natural gas-fired generation.

Coal Supply Strategy

Q. Please describe Tampa Electric's solid fuel usage and procurement strategy.

A. As with its natural gas strategy, Tampa Electric uses a portfolio approach to coal procurement. Big Bend Unit 4 is designed to burn high-sulfur Illinois Basin coal and is fully scrubbed for sulfur dioxide and nitrogen oxides, and the unit has been upgraded to operate on natural gas. Polk Unit 1 can burn a blend of petroleum coke and low sulfur coal, or natural gas. Each plant has varying operational and environmental restrictions and requires solid fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content, and chlorine content.

Coal is not a homogenous product. The fuel’s chemistry and contents vary based on many factors, including geography. The variability of the product dictates that Tampa Electric select its fuel based on multiple parameters. Those parameters include unique coal quality characteristics, price, availability, deliverability, and creditworthiness of the supplier.

To minimize costs, maintain operational flexibility, and ensure reliable supply, Tampa Electric typically maintains a portfolio of bilateral coal supply contracts with varying term lengths. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generation stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market. This market intelligence also helps shape the company's coal procurement strategy to reflect short- and long-term market conditions. Tampa Electric's strategy provides a stable supply of reliable fuel sources. In addition, this strategy allows the company the flexibility to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize how Tampa Electric will manage its solid fuel supply contracts through 2023.

A. Due to an event at an Illinois Basin mine last year that suspended mining operations for approximately six months, Tampa Electric has been managing supply interruptions and lower than projected solid fuel inventories for the last year. As domestic and international demand for coal has increased over the same period, we expect tight supply conditions to continue for the balance of the year and into 2023. Tampa Electric will supply the Big Bend and Polk Stations with solid fuel through a combination of existing inventory, short-term contracts, and, as necessary, spot purchases in support of the most economic commitment and dispatch for the generation fleet. Short-term and spot purchases allow the company to adjust supply to reflect changing coal quality and quantity needs, operational changes, and pricing opportunities.

Coal Transportation

Q. Please describe Tampa Electric's solid fuel transportation arrangements.

A. Tampa Electric can receive coal at its Big Bend Station via waterborne or rail delivery. Once delivered to Big Bend Station, solid fuel is consumed onsite, or blended and trucked to Polk Station for consumption in Polk Unit 1. As a result of declining solid fuel burns over the last few years, Tampa Electric now purchases delivered coal, where waterborne coal supply and transportation are arranged by the supplier. Procuring delivered waterborne coal continues to provide customers with competitive coal prices through a simplified process. Commodity and transportation of coal by rail is still being arranged separately, as necessary.

Q. Why does the company maintain multiple coal transportation options in its portfolio?

A. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers various benefits. Those benefits include 1) access to more potential coal suppliers, which results in a more competitively priced, and diverse, delivered coal portfolio; 2) the opportunity to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode; and 3) competition among transporters for future solid fuel transportation contracts. The benefits of bimodal solid fuel transportation were apparent in 2022 as coal deliveries by rail were not reliable due to labor shortages in the rail industry.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2022 and 2023?

A. Yes. Although we experienced supply and transport challenges this year, Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2022 and is evaluating how much coal to receive by rail in 2023.

Q. Please describe Tampa Electric’s expectations regarding waterborne coal deliveries.

A. Tampa Electric expects to receive the majority of its solid fuel supply in 2023 from waterborne deliveries to its unloading facilities at Big Bend Station. These deliveries come via the Mississippi River System or from foreign sources. The ultimate supply source is dependent upon quality, operational needs, and lowest overall delivered cost.

Q. Do you have any other updates to provide regarding Tampa Electric's solid fuel transportation portfolio?

A. Yes. Tampa Electric continues to burn natural gas as the economic fuel in Polk Unit 1. Big Bend Unit 4 is projected to burn coal in 2023. Although coal consumption has decreased relative to previous years, the expected coal burn in 2023 will be similar to 2022.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes. Tampa Electric diligently manages its mix of long-term, intermediate, and short-term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company's fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Q. Are there any other pertinent aspects of how Tampa Electric manages its fuel supply portfolio?

A. Yes. As part of Tampa Electric's 2017 Amended and Restated Stipulation and Settlement Agreement approved by Commission Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket No. 20170210-EI, and extended by the 2021 Stipulation and Settlement Agreement approved by Order No. PSC-2021-0423-S-EI issued on November 10, 2021 in Docket No. 20210034-EI, Tampa Electric has been operating under an Asset Optimization Mechanism since January 1, 2018. This Optimization Mechanism encourages Tampa Electric to market temporarily unused fuel supply assets to capture cost mitigation benefits for customers. These benefits have come through economic power purchases, economic power sales, resale of unneeded fuel supply, an asset management agreement for natural gas storage, and utilization of natural gas and solid fuel storage and transportation assets.

Projected 2023 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), S&P Scenario Planning Service Annual Guidebook (originally produced by PIRA Energy Group), the Energy Information Administration, and other energy market information sources. Future prices for energy commodities as traded on NYMEX, averaged over five consecutive business days ending August 1, 2022, form the basis of the natural gas and No. 2 oil market commodity price forecasts. The price projections for these two commodities are then adjusted to incorporate expected transportation costs and location differences.

Coal commodity and transportation prices are projected using contracted pricing and information from industry recognized consultants and published indices, such as IHS Markit and Argus *Coal Daily*. Also, the price projections are specific to the quality and mined location of coal utilized by Tampa Electric's Big Bend Unit 4 and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2023 projected fuel prices compare to the fuel prices projected for 2022 in the company’s mid-course correction filing?

A. Demand for natural gas in 2022 continued to outpace supply. Forward prices remain elevated through March 2023 and then decline as production is expected to increase into 2023 to balance the market. Higher gas demand is driven by LNG exports, low coal inventories, extreme summer weather, and low storage inventories. Production growth has been very slow as producers exercise capital discipline despite rising gas prices. In addition, the Ukraine invasion continues to impact the energy markets through increased volatility and uncertainty, which is expected to continue into 2023.

The commodity price for natural gas during 2023 is projected to be higher ($5.74 per MMBtu) than the 2022 price ($3.73 per MMBtu) projected in the company’s mid-course correction fuel filing. The 2023 delivered coal price projection is higher ($90.57 per ton) than the price projected for 2022 ($84.55 per ton) during preparation of the 2022 mid-course correction fuel clause factors.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY
OF
BENJAMIN F. SMITH II

FILED: SEPTEMBER 2, 2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

Q. Please state your name, address, occupation, and employer.

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Origination within the Fuel and Planning Services Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida, and a Master of Business Administration degree in 2015 from Saint Leo University in Saint Leo, Florida. I am also a registered Professional Engineer within the State of Florida and a Certified Energy Manager through the Association of Energy Engineers. I joined Tampa Electric in 1990 as a cooperative education student.

During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager, Gas and Power Origination within the Origination and Trading Department. My responsibilities are to evaluate short and long-term power purchase and sale opportunities within the wholesale power market, assist in wholesale power and gas transportation origination and contract structures, and assist in combustion byproduct contract administration and market opportunities. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, other wholesale developers and independent power producers, as well as with natural gas pipeline owners and transporters.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I have testified before this Commission in Docket Nos. 20030001-EI, 20040001-EI, and 20080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide a description of Tampa Electric's purchased power agreements that the company has entered and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe Tampa Electric's purchased power strategy for mitigating price and supply-side risk, while providing customers with a reliable supply of economically priced purchased power.

Q. Please describe the efforts Tampa Electric makes to ensure that its wholesale purchases and sales activities are conducted in a reasonable and prudent manner.

A. Tampa Electric evaluates potential purchase and sale opportunities by analyzing the expected available amounts of generation and power required to meet the projected demand and energy of its customers. Purchases are made to achieve reserve margin requirements, meet customers' demand and energy needs, meet operating reserve requirements, supplement generation during unit outages, and for economical purposes. When Tampa Electric considers making a power purchase, the company diligently searches for available supplies of wholesale capacity or energy from creditworthy counterparties. The objective is to secure reliable quantities of purchased power for customers at the best possible price.

Conversely, when there is a sales opportunity, the company offers profitable wholesale capacity or energy products to creditworthy counterparties. The company has wholesale power purchase and sale transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's wholesale purchase and sale activities are conducted in a reasonable and prudent manner.

Q. Has Tampa Electric reasonably managed its wholesale power purchases and sales for the benefit of its retail customers?

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's Order No. PSC-1997-0262-FOF-EI, approved on March 11, 1997 and issued in Docket No. 19970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs and improve reliability. The company monitors its contractual rights with purchased power suppliers, as well as with entities to which wholesale power is sold, to detect and prevent any breach of the company’s contractual rights. Tampa Electric continually strives to improve its knowledge of wholesale power markets and available opportunities within the marketplace. The company uses this knowledge to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power is available on Tampa Electric’s system and market conditions allow.

Q. Please describe Tampa Electric’s 2022 wholesale power purchases.

A. Tampa Electric assessed the wholesale power market and entered into short- and long-term purchases based on price and availability of supply. Approximately 7 percent of the company’s expected needs for 2022 will be met using purchased power. This includes economy energy purchases, reliability purchases, as-available purchases from qualifying facilities, and forward purchases from Duke Energy Florida (“DEF”), the Florida Municipal Power Agency (“FMPA”), and Florida Power & Light (“FPL”).

Presently, Tampa Electric has four forward purchases applicable to the year 2022, and those purchases are summarized below.

- A non-firm purchase from DEF, which was an extension of Tampa Electric’s previous contract to purchase non-firm energy from DEF. In November 2021, Tampa Electric and DEF extended this contract to cover the period December 2021 through October 2022. The energy volume available under the contract remains at a maximum of 515 MW per hour. The DEF extension does not have a must-take obligation and provides Tampa Electric the flexibility to schedule the energy when beneficial to customers. As an added component to this latest extension, 250 MW of the contract was available as a firm call option for the months of January and February 2022. The firm portion of the purchase was for reliability to ensure energy service to customers in the event Tampa Electric experienced cold weather. The purchase supported the company’s plan to lower exposure to natural gas risk during its winter peak. The company’s plan to minimize its natural gas risk is addressed in the testimony of witness John Heisey. Since the contract extension, the purchase has provided $6.7 million in projected savings to customers, which flow through the optimization mechanism. These savings to customers include only the utilization of the purchase as non-firm, economy (i.e., excludes the 250 MW firm call option portion). These savings flow through the company’s optimization mechanism and benefit customers in accordance with the methodology approved by the Commission in Order No. 2017-0456-S-EI, issued on November 27, 2017 and extended through December 31, 2024 as approved by the Commission in Order No. PSC-2021-0423-S-EI issued on November 10, 2021, in Docket No. 20210034-EI.

- A 50 MW firm peaking call option from FMPA executed November 2021 for the period January through February 2022. The firm purchase from FMPA was for reliability to ensure energy service to customers in the event Tampa Electric experienced unusually cold weather.

The company’s remaining two forward purchases are from FPL, executed in February 2022. A description of the purchases follows.

- The two FPL purchases are non-firm, economy, must-take energy purchases. Each purchase is for 150 MW. One covers the period May through October 2022. The other covers the period May through September 2022. The purchases provide a projected $4.6 million in savings to customers, which flow through the optimization mechanism.

At the time of the 2022 Projection filing, Tampa Electric did not expect forward purchases for 2022. However, the company did expect to incur capacity costs to be recovered through its 2022 Capacity Cost Recovery Clause in the form of projected firm transmission services. The projected capacity clause costs for firm transmission totaled $5.9 million and would be in support of firm purchases for the Big Bend Modernization project ("Modernization Project") testing, if needed, as well as economic forward purchases. Although the company did not make firm purchases in support of testing at Big Bend, it did make the previously mentioned must-take economy purchases from FPL, which required the purchase of firm transmission. Currently, the projected 2022 transmission costs to be recovered through the 2022 Capacity Cost Recovery Clause is about $5.1 million.

Tampa Electric has not secured other forward purchases for 2022 at this time. However, the company constantly searches for economic purchase opportunities that benefit customers. As other purchase opportunities materialize, the company evaluates each product to determine the viability of making it part of the supply portfolio Tampa Electric uses to serve customers.

Q. Does Tampa Electric anticipate entering into new wholesale power purchases for 2023 and beyond?

A. Tampa Electric currently has no forward purchases for 2023 and, at this time, projects approximately 1 percent of the company's expected needs for 2023 will be met using purchased power. However, the company will search for forward economy purchase opportunities, which could result in capacity costs from the purchase of firm transmission services. Thus, the company has included a forecast of these transmission costs in its 2023 Capacity Cost Recovery Clause projection. The projected capacity clause costs total $1.7 million and support economic forward purchases. A further explanation of these transmission costs is below.

Over the past several years, as noted previously with the economic purchases from FPL in 2022, Tampa Electric has identified forward, season-long economy energy purchases that produced savings for customers, and it will seek out such beneficial purchases again in 2023. However, with the operation of the highly efficient Modernization Project, the company anticipates a lower volume of forward economy purchases than in previous years. Hence, the projected transmission costs for 2023 are lower than the projection for 2022. The company’s projected transmission costs are based on its expected system energy costs with the Modernization Project in service and market expectations. While Tampa Electric has yet to identify and secure economic purchase opportunities for 2023, the company included in its projection the dollars associated with these transmission costs. The terms of the company’s recent forward economy purchases were generally in the April through November timeframe and for about 300 MW. In 2023, the company's transmission cost projection is for 100 MW over the May through October timeframe.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchased power supplies during major weather-related events, such as hurricanes?

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions. The strategy includes monitoring storm activity; evaluating the impact of storms on existing forward purchases and the rest of the wholesale power market; communicating with suppliers about their storm preparations and potential impacts to existing transactions, purchasing additional power on the forward market, if appropriate, for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing sellers' fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Absent the threat of a hurricane, and for all other months of the year, the company evaluates economic combinations of short- and long-term purchase opportunities in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2022 and 2023.

A. Tampa Electric entered into various non-separated (*e.g.,* next-hour and next-day sales) wholesale sales in 2022, and the company anticipates making additional non-separated sales during the balance of 2022 and 2023. The gains from these sales are shared between Tampa Electric and its customers through the company's optimization mechanism.

Q. Please summarize your direct testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and these efforts benefit the company’s customers. Tampa Electric’s energy supply strategy includes self-generation and short- and long-term power purchases. The company purchases in both physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. In addition to the cost benefits, this purchased power approach employs a diversified physical power supply strategy that enhances reliability. The company also enters wholesale sales that benefit customers when market conditions allow.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY

OF

PENELOPE A. RUSK

FILED: SEPTEMBER 2, 2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

Q. Please state your name, address, occupation, and employer.

A. My name is Penelope A. Rusk. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Senior Director, Regulatory Affairs in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I hold bachelor's and master's degrees in Economics, and I have over 20 years of electric utility experience. Currently, I oversee and am responsible for Tampa Electric's Regulatory Affairs department activities, including the areas of cost recovery clauses, base rate cases, rate design, cost of service, demand and energy forecasting, and other analyses. I have regulatory experience in a variety of areas, and I have appeared before this Commission to answer questions in a number of dockets. I also oversee the coordination and submission of the Tampa Electric and Peoples Gas filings with federal and state regulatory agencies. I am a member of the Southeastern Electric Exchange Rates and Regulation Committee.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Tampa Electric’s 2022 fuel and purchased power cost under-recovery and the company’s proposed treatment of that amount.

Q. What is Tampa Electric’s projection of the 2022 fuel cost under-recovery?

A. In Tampa Electric’s actual/estimated true-up filing submitted to the Commission on July 27, 2022, Tampa Electric estimated its 2022 fuel cost under-recovery to be $411,964,625.

Q. Has Tampa Electric since revised its expectations regarding the projected 2022 under-recovery?

A. Yes. Based on current natural gas pricing, the company now expects the 2022 fuel under-recovery to be significantly higher than shown in the July 27, 2022 filing. The primary driver of the projected under-recovery is rising natural gas prices. During 2022, the natural gas market has been and continues to be extremely volatile.

Q. Did Tampa Electric include the projected under-recovery in its proposed 2023 fuel cost recovery factors?

A. No. Due to the extreme volatility of the natural gas market, Tampa Electric has not included the 2022 projected under-recovery in its 2023 fuel and purchased power cost recovery factors at this time.

Q. How does Tampa Electric intend to recover the costs associated with its 2022 under-recovery?

A. Tampa Electric proposes to continue to monitor natural gas prices until the amount of the fuel cost under-recovery is more certain and will make a request to recover the 2022 under-recovery.

Q. Does this conclude your direct testimony?

A. Yes.