AUSLEY MCMULLEN
ATTORNEYS AND COUNSELORS AT LAW

123 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

September 3, 2019

VIA: ELECTRONIC FILING

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

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 20190001-EI

Dear Mr. Teitzman:

Attached for filing in the above docket on behalf of Tampa Electric Company are the following:

1. Petition of Tampa Electric Company.
2. Prepared Direct Testimony and Exhibit (PAR-3) of Penelope A. Rusk.
3. Prepared Direct Testimony and Exhibit (JC-1) of Jeremy Cain.
4. Prepared Direct Testimony of John Heisey.
5. Prepared Direct Testimony of Benjamin F. Smith II.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

cc: All Parties of Record (w/attachment)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition and Testimonies, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 3rd day of September 2019, to the following:

Ms. Suzanne S. Brownless
Special Counsel
Office of the General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
sbrownle@psc.state.fl.us

Mr. J. R. Kelly
Ms. Patricia A. Christensen
Office of Public Counsel
111 West Madison Street – Room 812
Tallahassee, FL 32399-1400
christensen.patty@leg.state.fl.us
kelly.jr@leg.state.fl.us

Ms. Dianne M. Triplett
Associate General Counsel
Duke Energy Florida, LLC
299 First Avenue North
St. Petersburg, FL 33701
Dianne.triplett@duke-energy.com
FLRegulatoryLegal@duke-energy.com

Mr. Matthew R. Bernier
Senior Counsel
Duke Energy Florida, LLC
106 East College Avenue, Suite 800
Tallahassee, FL 32301-7740
Matthew.bernier@duke-energy.com

Mr. Jon C Moyle, Jr.
Moyle Law Firm
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com

Ms. Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 S. Monroe St., Suite 601
Tallahassee, FL 32301
bkeating@gunster.com

Ms. Maria Jose Moncada
Senior Attorney
Mr. Joel T. Baker
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard (LAW/JB)
Juno Beach, FL 33408-0420
maria.moncada@fpl.com
joel.baker@fpl.com

Mr. Kenneth Hoffman
Vice President, Regulatory Relations
Florida Power & Light Company
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1859
ken.hoffman@fpl.com

Mr. Mike Cassel
Regulatory and Governmental Affairs
Florida Public Utilities Company
Florida Division of Chesapeake Utilities Corp.
1750 SW 14th Street, Suite 200
Fernandina Beach, FL 32034
mcassel@fpuc.com

Mr. Russell A. Badders
Vice President & Associate General Counsel
Gulf Power Company
One Energy Place
Russell.Badders@nexteraenergy.com

Mr. Steven R. Griffin
Beggs & Lane
Post Office Box 12950
Pensacola, FL 32591
srg@beggslane.com

Ms. Holly Henderson
Senior Manager Regulatory Affairs
Gulf Power Company
215 South Monroe Street, Suite 618
Tallahassee, FL 32301
Holly.Henderson@nexteraenergy.com

Mr. James W. Brew
Ms. Laura A. Wynn
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson Street, NW
Eighth Floor, West Tower
Washington, D.C. 20007-5201
jbrew@smxblaw.com
laura.wynn@smxblaw.com

Mr. Robert Scheffel Wright
Mr. John T. LaVia, III
Gardner, Bist, Wiener, Wadsworth,
Bowden, Bush, Dee, LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, FL 32308
Schef@gbwlegal.com
Jlavia@gbwlegal.com

ATTORNEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	))))	DOCKET NO. 20190001-EI FILED: September 3, 2019

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, generating performance incentive factors, and optimization mechanism set forth herein, and in support thereof, says:

Fuel and Purchased Power Factors

1. Tampa Electric projects its fuel and purchased power net true-up amount for the period January 1, 2020 through December 31, 2020 will be an under-recovery of $30,742,026. (See Exhibit No. PAR-3, Document No. 2, Schedule E1-C).

2. The company's projected expenditures for the period January 1, 2020 through December 31, 2020, when adjusted for the proposed GPIF reward and true-up under-recovery amount and spread over projected kilowatt-hour sales for the period January 1, 2020 through December 31, 2020, produce a fuel and purchased power factor for the new period of 3.016 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. (See Exhibit No. PAR-3, Document No. 2, Schedule E1-E).

Capacity Cost Factor

4. Tampa Electric estimates that its net true-up amount applicable for the period January 1, 2020 through December 31, 2020 will be an under-recovery of $2,179,217, as shown in Exhibit No. PAR-3, Document No. 1, page 2 of 4.

5. The company's projected expenditures for the period January 1, 2020 through December 31, 2020, 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 0.008 cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is $0.03 per billed kW as set forth in Exhibit No. PAR-3, Document No. 1, page 3 of 4.

GPIF

6. Tampa Electric has calculated that it is subject to a GPIF reward of $4,141,330 for performance during the period January 1, 2018 through December 31, 2018, included in Exhibit No. PAR-3, Document No. 2, Schedule E1-C.

7. The company is also proposing GPIF targets and ranges for the period January 1, 2020 through December 31, 2020 with such proposed targets and ranges being detailed in the testimony and exhibits of Tampa Electric witness Jeremy B. Cain filed herewith.

Optimization Mechanism

8. Tampa Electric has calculated that it is subject to an Optimization Mechanism sharing amount of $1,120,353, included in Exhibit No. PAR-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, GPIF, and optimization mechanism be approved as they relate to prior period true-up calculations and projected cost recovery charges.

DATED this 3rd day of September, 2019.

Respectfully submitted,

JAMES D. BEASLEY
jbeasley@ausley.com
J. JEFFRY WAHLEN
jwahlen@ausley.com
MALCOLM N. MEANS
mmeans@ausley.com
Ausley McMullen
Post Office Box 391
Tallahassee, Florida 32302
(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 3rd day of September 2019, to the following:

Ms. Suzanne S. Brownless
Special Counsel
Office of the General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
sbrownle@psc.state.fl.us

Mr. J. R. Kelly
Ms. Patricia A. Christensen
Office of Public Counsel
111 West Madison Street – Room 812
Tallahassee, FL 32399-1400
christensen.patty@leg.state.fl.us
kelly.jr@leg.state.fl.us

Ms. Dianne M. Triplett
Associate General Counsel
Duke Energy Florida, LLC
299 First Avenue North
St. Petersburg, FL 33701
Dianne.triplett@duke-energy.com
FLRegulatoryLegal@duke-energy.com

Mr. Matthew R. Bernier
Senior Counsel
Duke Energy Florida, LLC
106 East College Avenue, Suite 800
Tallahassee, FL 32301-7740
Matthew.bernier@duke-energy.com

Mr. Jon C Moyle, Jr.
Moyle Law Firm
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com

Ms. Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 S. Monroe St., Suite 601
Tallahassee, FL 32301
bkeating@gunster.com

Ms. Maria Jose Moncada
Senior Attorney
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Principal Attorney
Florida Power & Light Company
700 Universe Boulevard (LAW/JB)
Juno Beach, FL 33408-0420
maria.moncada@fpl.com
joel.baker@fpl.com

Mr. Kenneth Hoffman
Vice President, Regulatory Relations
Florida Power & Light Company
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1859
ken.hoffman@fpl.com

Mr. Mike Cassel
Regulatory and Governmental Affairs
Florida Public Utilities Company
Florida Division of Chesapeake Utilities Corp.
1750 SW 14th Street, Suite 200
Fernandina Beach, FL 32034
mcassel@fpuc.com

Mr. Russell A. Badders
Vice President & Associate General Counsel
Gulf Power Company
One Energy Place
Russell.Badders@nexteraenergy.com

Mr. Steven R. Griffin
Beggs & Lane
Post Office Box 12950
Pensacola, FL 32591
srg@beggslane.com

Ms. Holly Henderson
Senior Manager Regulatory Affairs
Gulf Power Company
215 South Monroe Street, Suite 618
Tallahassee, FL 32301
Holly.Henderson@nexteraenergy.com

Mr. James W. Brew
Ms. Laura A. Wynn
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson Street, NW
Eighth Floor, West Tower
Washington, D.C. 20007-5201
jbrew@smxblaw.com
laura.wynn@smxblaw.com

Mr. Robert Scheffel Wright
Mr. John T. LaVia, III
Gardner, Bist, Wiener, Wadsworth,
Bowden, Bush, Dee, LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, FL 32308
Schef@gbwlegal.com
Jlavia@gbwlegal.com

ATTORNEY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20190001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2020 THROUGH DECEMBER 2020

TESTIMONY AND EXHIBIT

OF

PENELOPE A. RUSK

FILED: SEPTEMBER 3, 2019

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 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Regulatory Affairs.

Q. Have you previously filed testimony in Docket No. 20190001-EI?

A. Yes, I submitted direct testimony on March 1, 2019 and July 26, 2019.

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

A. No, it has 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, the proposed annual levelized fuel and purchased power cost recovery factors for January 2020 through December 2020. 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 2020.

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

A. Yes. Exhibit No. PAR-3, consisting of four 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 2020 through December 2020 as well as Schedule H1 for 2017 through 2020. 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. Document No. 4 presents the capital costs and fuel savings for the company projects that have been approved through the fuel clause, as well as the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the projects.

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. PAR-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. PAR-3, Document No. 1, Tampa Electric requests recovery of $1,620,007 after jurisdictional separation, prior year true-up, and application of the revenue tax factor, for estimated expenses in 2020.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2020 through December 2020.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor $ per Kw
RS Secondary	0.010	
GS and CS Secondary	0.008	
GSD, SBF Standard		
Secondary		0.03
Primary		0.03
Transmission		0.03
IS, IST, SBI		
Primary		0.03
Transmission		0.03
GSD Optional		
Secondary	0.007	
Primary	0.007	
Transmission	0.007	
LS1 Secondary	0.002	

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

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.008 cents per kWh compare to the factor for April 2019 through December 2019?

A. The proposed capacity cost recovery factor of 0.008 cents per kWh for the January 2020 through December 2020 period is 0.017 cents per kWh (or $0.17 per 1,000 kWh) greater than the average capacity cost recovery factor credit of 0.009 cents per kWh for the April 2019 through December 2019 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 year 2020?

A. The appropriate amount for the 2020 period is 3.016 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. PAR-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 2020 through December 2020.

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 $4,141,330, 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 amount to be applied during the January 2020 through December 2020 period. The net true-up amount is an under-recovery of $30,742,026. Lastly, Schedule E1-C indicates the Optimization Mechanism gain of $1,120,353.

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 2020 through December 2020. 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. PAR-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 January 2020 through December 2020.

A.

Metering Voltage Level	Fuel Charge Factor (Cents per kWh)
Secondary	3.016
Tier I (Up to 1,000 kWh)	2.702
Tier II (Over 1,000 kWh)	3.702
Distribution Primary	2.986
Transmission	2.956
Lighting Service	2.989
Distribution Secondary	3.162 (on-peak)
	2.953 (off-peak)

Metering Voltage Level	Fuel Charge Factor (Cents per kWh)
Distribution Primary	3.130 (on-peak)
	2.923 (off-peak)
Transmission	3.099 (on-peak)
	2.894 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.016 cents per kWh compare to the levelized fuel adjustment factor for the April 2019 through December 2019 period?

A. The proposed fuel charge factor of 3.016 cents per kWh is 0.211 cents per kWh (or $2.11 per 1,000 kWh) lower than the average fuel charge factor of 3.227 cents per kWh for the April 2019 through December 2019 period.

Capital Projects Approved for Fuel Clause Recovery

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project costs for the period January 2020 through December 2020?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, are $1,657,489. This is shown in Exhibit No. PAR-3, Document No. 4.

Q. Does Tampa Electric's estimated Big Bend Units 1-4 ignition oil conversion project fuel savings exceed costs for the period January 2020 through December 2020?

A. Yes, fuel savings exceed costs for the period January 2020 through December 2020. This information is also presented in Exhibit No. PAR-3, Document No. 4.

Q. Should Tampa Electric's Big Bend Units 1-4 ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2020 through December 2020 estimated fuel savings are greater than the projected capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-2014-0309-PAA-EI, issued in Docket No. 20140032-EI on June 12, 2014.

Q. Please describe the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for this project.

A. The capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the company’s projects that are approved for recovery through the fuel clause are shown in Document No. 4.

Q. Is Tampa Electric required to adjust its projected weighted average cost of capital calculations to avoid a tax normalization violation, which may occur in certain circumstances described in the utilities’ unopposed joint motion to modify Order No. 2012-0425-PAA-EU, submitted in this docket on August 21, 2019?

A. No, an adjustment is not required for 2020. Tampa Electric expects to meet the limitation provision for the projected period. Therefore, the methodology used to calculate the revenue requirement rate of return shown on Document No. 4 is that described in Order No. 2012-0425-PAA-EU, and the use of the current methodology does not violate the tax normalization requirement.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric project a 2020 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 existing short-term wholesale sales incentive mechanism, and as a result no wholesale incentive benchmark is required for the 2020 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 a decrease of $1.06 beginning January 2020, when compared to the April 2019 through December 2019 charges. For the month of January 2020, a one-time final tax savings credit will be applied to customer bills. For a 1,000 kWh residential bill, the credit represents an additional decrease of $9.06. These amounts are shown in Exhibit No. PAR-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 2020.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2020 - DECEMBER 2020

AND

SCHEDULE E12

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2020 THROUGH DECEMBER 2020
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	54.99%	9,587,607	1,990	1.08045	1.05238	10,089,768	2,150	49.25%	56.99%	56.40%
GS, CS	62.24%	984,036	180	1.08045	1.05236	1,035,556	195	5.05%	5.17%	5.16%
GSD Optional	4.71%	508,686	77	1.07575	1.04878	533,502	83	2.60%	2.20%	2.23%
GSD, SBF	70.76%	7,637,641	1,155	1.07575	1.04878	8,010,233	1,243	39.09%	32.94%	33.41%
IS,SBI	79.71%	649,419	93	1.02851	1.01705	660,489	96	3.22%	2.54%	2.59%
LS1	333.63%	154,170	5	1.08045	1.05238	162,245	6	0.79%	0.16%	0.21%
TOTAL		19,521,559	3,501			20,491,793	3,773	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2019 projected calendar data.
(2) Projected MWH sales for the period January 2020 thru December 2020.
(3) Based on 12 months average CP at meter.
(4) Based on 2019 projected demand losses.
(5) Based on 2019 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 2020 THROUGH DECEMBER 2020
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	0	0	0	0	0	0	0	0	0	0	0	570,000	570,000
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(UNIT POWER CAPACITY REVENUES)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(1,130,376)
4	TOTAL CAPACITY DOLLARS	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	$475,802	($560,376)
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	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	$475,802	($560,376)
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2019 - DEC. 2019													2,179,217
8	TOTAL													$1,618,841
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$1,620,007

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2020 THROUGH DECEMBER 2020
PROJECTED

RATE CLASS	(1) PERCENTAGE OF SALES AT GENERATION (%)	(2) PERCENTAGE OF DEMAND AT GENERATION (%)	(3) ENERGY RELATED COSTS ($)	(4) DEMAND RELATED COSTS ($)	(5) TOTAL CAPACITY COSTS ($)	(6) PROJECTED SALES AT METER (MWH)	(7) EFFECTIVE AT SECONDARY LEVEL (MWH)	(8) BILLING KW LOAD FACTOR (%)	(9) PROJECTED BILLED KW AT METER (kw)	(10) CAPACITY RECOVERY FACTOR ($/kw)	(11) CAPACITY RECOVERY FACTOR ($/kwh)
RS	49.25%	56.99%	61,356	852,244	913,600	9,587,607	9,587,607				0.00010
GS, CS	5.05%	5.17%	6,291	77,314	83,605	984,036	984,036				0.00008
GSD, SBF											
Secondary						6,246,534	6,246,534			0.03	
Primary						1,382,339	1,368,516			0.03	
Transmission						8,768	8,593			0.03	
GSD, SBF - Standard	39.09%	32.94%	48,698	492,594	541,292	7,637,641	7,623,643	58.93%	17,722,132		
GSD - Optional	2.60%	2.20%	3,239	32,899	36,138						
Secondary						498,981	498,981				0.00007
Primary						9,705	9,608				0.00007
Transmission						0	0				0.00007
IS, SBI											
Primary						116,796	115,628			0.03	
Transmission						532,623	521,971			0.03	
Total IS, SBI	3.22%	2.54%	4,011	37,984	41,995	649,419	637,599	54.21%	1,611,184		
LS1	0.79%	0.16%	984	2,393	3,377	154,170	154,170				0.00002
TOTAL	100.00%	100.00%	124,579	1,495,428	1,620,007	19,521,559	19,495,644				0.00008

(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 2020 through December 2020.
(7) Projected kWh sales at secondary for the period January 2020 through December 2020.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2020 through December 2020.
(10) Total Col (5) / Total Col (9).
(11) {Col (5) / Total Col (7)} / 1000.

SCHEDULE E12

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

CONTRACT	TERM START	TERM END	CONTRACT TYPE	
				QF = QUALIFYING FACILITY LT = LONG TERM ST = SHORT-TERM
SEMINOLE ELECTRIC **	6/1/1992	--------	LT	** 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	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
VARIOUS	[redacted]												
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	475,802	(560,376)
TOTAL CAPACITY	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**$475,802**	**($560,376)**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2020 - DECEMBER 2020

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 2020 THROUGH DECEMBER 2020

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	541,616,128	20,296,164	2.66856
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Big Bend Units 1-4 Igniters Conversion Project	1,657,489	20,296,164 [1]	0.00817
4b.	Adjustment	0	0	0.00000
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**543,273,617**	**20,296,164**	**2.67673**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	78,030	1,900	4.10684
7.	Energy Cost of Economy Purchases (E9)	4,058,520	86,120	4.71263
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	3,680,810	123,930	2.97007
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**7,817,360**	**211,950**	**3.68830**
11.	**TOTAL AVAILABLE MWH (LINE 5 + LINE 10)**		**20,508,114**	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	196,640	6,910	2.84573
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	0	0	0.00000
14.	Gains on Sales	11,744	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**208,384**	**6,910**	**3.01569**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		307	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**550,882,593**	**20,500,897**	**2.68711**
20.	Net Unbilled	NA [1][a]	NA [a]	NA
21.	Company Use	999,605 [1]	37,200	0.00513
22.	T & D Losses	25,881,416 [1]	963,169	0.13272
23.	System MWH Sales	550,882,593	19,500,528	2.82496
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	550,882,593	19,500,528	2.82496
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	550,882,593	19,500,528	2.82496
28.	Optimization Mechanism [2]	1,120,353	19,500,528	0.00575
29.	True-up [2]	30,742,026	19,500,528	0.15765
30.	Total Jurisdictional Fuel Cost (Excl. GPIF)	582,744,972	19,500,528	2.98835
31.	Revenue Tax Factor			1.00072
32.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	583,164,548	19,500,528	2.99050
33.	GPIF Adjusted for Taxes [2]	4,141,330	19,500,528	0.02124
34.	**Fuel Factor Adjusted for Taxes Including GPIF**	587,305,878	19,500,528	3.01174
35	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.012**

[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 2020 THROUGH DECEMBER 2020

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2019 - December 2019 (6 months actual, 6 months estimated)	($27,562,704)
2.	PROJECTED UNDER-RECOVERY TRUE-UP INCLUDED IN APRIL - DECEMBER 2019 RATES (Per Mid-Course correction Schedule E1-C, line 1B)	($35,545,462)
3.	DIFFERENCE IN 2018 ESTIMATED TRUE-UP AMOUNT PROJECTED IN ORIGINAL 2019 RATES AND AMOUNT COLLECTED IN 2019 ($7,015,485 over-recovery less $584,624 refunded each month January through March 2019)	$5,261,613
4.	ACTUAL-ESTIMATED 2019 OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2020 (Line 1 - Line 2 + Line 3)	$13,244,371
5.	FINAL TRUE-UP (January 2018 - December 2018) (Per True-Up filed March 1, 2019)	(43,986,397)
6.	TOTAL OVER/(UNDER) RECOVERY (Line 4 + Line 5) To be included in the 12-month projected period January 2020 through December 202((Schedule E1, line 28)	($30,742,026)
7.	JURISDICTIONAL MWH SALES (Projected January 2020 through December 2020)	19,500,528
8.	TRUE-UP FACTOR - cents/kWh (Using Effective MWh Sales of 19,474,612)	**0.1579**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2020 through December 2020)	$4,141,330	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2020 through December 2020)	($30,742,026)	
	C. OPTIMIZATION MECHANISM GAIN / (LOSS) (January 2020 through December 2020)	$1,120,353	
2.	TOTAL SALES (January 2020 through December 2020)	19,500,528	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR (Using Effective MWh Sales of 19,474,612)	**0.0213**	Cents/kWh
	B. TRUE-UP FACTOR (Using Effective MWh Sales of 19,474,612)	**0.1579**	Cents/kWh
	C. OPTIMIZATION MECHANISM FACTOR (Using Effective MWh Sales of 19,474,612)	**0.0058**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	29.95	$23.72
OFF PEAK	70.05	$22.15
	100.00	1.0709

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$550,882,593		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	19,500,528		
2a	Effective MWH Sales (Jurisd)		19,474,612		
3	Cost Per KWH Sold	(line 1 / line 2)	2.8250		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		NA		
6	True-Up	(Sch E1 line 29)	$30,742,026		
7	Optimization Mechanism	(Sch E1 line 28)	$1,120,353		
8	TOTAL	(line 1 x line 4) + line 6 + line 7	$582,744,972		
9	Revenue Tax Factor		1.00072		
10	Recovery Factor	(line 8 x line 9) / line 2a / 10	2.9945		
11	GPIF Factor	(Sch E1-C line 3A)	0.0213		
12	Recovery Factor Including GPIF	(line 10 + line 11)	3.0158	3.1624	2.9531
13	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.016	3.162	2.953

14	Hours: ON PEAK	25.39%
15	OFF PEAK	74.61%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Line Loss	Secondary
Distribution Secondary	17,450,297		17,450,297
Distribution Primary	1,508,840	0.99	1,493,752
Transmission	541,391	0.98	530,563
Total	19,500,528		19,474,612

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.016	3.162	2.953
Distribution Primary	2.986	3.130	2.923
Transmission	2.956	3.099	2.894
RS 1st Tier	2.702		
RS 2nd Tier	3.702		
Lighting	2.989		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

METERING VOLTAGE LEVEL	LEVELIZED FUEL RECOVERY FACTOR cents/kWh	FIRST TIER (Up to 1000 kWh) cents/kWh	SECOND TIER (OVER 1000 kWh) cents/kWh
STANDARD			
Distribution Secondary (RS only)		2.702	3.702
Distribution Secondary	3.016		
Distribution Primary	2.986		
Transmission	2.956		
Lighting Service [1]	2.989		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.162		
Distribution Secondary - Off-Peak	2.953		
Distribution Primary - On-Peak	3.130		
Distribution Primary - Off-Peak	2.923		
Transmission - On-Peak	3.099		
Transmission - Off-Peak	2.894		

(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 2020 THROUGH DECEMBER 2020

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
						ESTIMATED							TOTAL
	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	PERIOD
1. Fuel Cost of System Net Generation	44,880,984	38,132,255	38,521,895	38,369,419	43,090,030	50,237,743	53,414,246	55,164,897	51,815,437	46,376,579	38,768,531	42,844,112	541,616,128
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold [1]	17,750	16,352	16,012	17,782	19,086	18,800	16,987	16,722	19,033	15,991	17,030	16,839	208,384
4. Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	78,030	78,030
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	282,290	274,130	286,020	293,010	306,640	300,450	327,220	332,740	290,490	341,270	353,060	293,490	3,680,810
7. Energy Cost of Economy Purchases	17,480	46,010	230,400	124,990	534,220	522,050	178,720	440,030	349,380	1,169,790	244,200	201,250	4,058,520
8. Big Bend Units 1-4 Igniters Conversion Project	357,944	355,688	353,433	351,177	239,247	0	0	0	0	0	0	0	1,657,489
9. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
10. TOTAL FUEL & NET POWER TRANSACTIONS	**45,520,948**	**38,791,731**	**39,375,736**	**39,120,814**	**44,151,051**	**51,041,443**	**53,903,199**	**55,920,945**	**52,436,274**	**47,871,648**	**39,348,761**	**43,400,043**	**550,882,593**
11. Jurisdictional MWH Sold	1,500,869	1,346,196	1,325,733	1,421,475	1,564,939	1,823,864	1,909,750	1,931,881	1,952,467	1,795,872	1,500,089	1,427,393	19,500,528
12. Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
13. Jurisdictional Total Fuel & Net Power Transactions (Line 10 * Line 12)	45,520,948	38,791,731	39,375,736	39,120,814	44,151,051	51,041,443	53,903,199	55,920,945	52,436,274	47,871,648	39,348,761	43,400,043	550,882,593
14. Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
15. JURISD. TOTAL FUEL & NET PWR. TRANS. Adjusted for Line Losses (Line 13 * Line 14)	**45,520,948**	**38,791,731**	**39,375,736**	**39,120,814**	**44,151,051**	**51,041,443**	**53,903,199**	**55,920,945**	**52,436,274**	**47,871,648**	**39,348,761**	**43,400,043**	**550,882,593**
16. Cost Per kWh Sold (Cents/kWh)	3.0330	2.8816	2.9701	2.7521	2.8213	2.7985	2.8225	2.8946	2.6856	2.6656	2.6231	3.0405	2.8250
17. Optimization Mechanism (Cents/kWh) [2]	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058
18. True-up (Cents/kWh) [2]	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579
19. Total (Cents/kWh) (Line 16+17+18)	3.1967	3.0453	3.1338	2.9158	2.9850	2.9622	2.9862	3.0583	2.8493	2.8293	2.7868	3.2042	2.9887
20. Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
21. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.1990	3.0475	3.1361	2.9179	2.9871	2.9643	2.9884	3.0605	2.8514	2.8313	2.7888	3.2065	2.9909
22. GPIF Adjusted for Taxes (Cents/kWh) [2]	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213
23. TOTAL RECOVERY FACTOR (LINE 21+22)	**3.2203**	**3.0688**	**3.1574**	**2.9392**	**3.0084**	**2.9856**	**3.0097**	**3.0818**	**2.8727**	**2.8526**	**2.8101**	**3.2278**	**3.0122**
24. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**3.220**	**3.069**	**3.157**	**2.939**	**3.008**	**2.986**	**3.010**	**3.082**	**2.873**	**2.853**	**2.810**	**3.228**	**3.012**

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

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

SCHEDULE E3

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	317,757	297,257	317,757	240,881	297,257	307,507
3. COAL	4,796,166	274,531	0	824,594	142,161	2,135,479
4. NATURAL GAS	39,767,061	37,560,467	38,204,138	37,303,944	42,650,612	47,794,757
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**44,880,984**	**38,132,255**	**38,521,895**	**38,369,419**	**43,090,030**	**50,237,743**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	1,328	1,242	1,328	1,007	1,243	1,286
10. COAL	110,520	6,580	0	19,440	3,330	50,180
11. NATURAL GAS	1,319,091	1,209,907	1,308,921	1,388,433	1,619,817	1,759,724
12. SOLAR	87,260	99,820	122,030	147,960	161,380	138,420
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,518,199**	**1,317,549**	**1,432,279**	**1,556,840**	**1,785,770**	**1,949,610**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	2,492	2,332	2,492	1,890	2,331	2,412
17. COAL (TON)	62,380	3,830	0	10,610	1,840	28,040
18. NATURAL GAS (MCF)	9,335,262	8,907,432	9,459,532	10,268,582	11,926,772	13,351,492
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	14,614	13,671	14,614	11,079	13,671	14,143
23. COAL	1,403,530	86,270	0	238,710	41,410	630,980
24. NATURAL GAS	9,579,066	9,147,029	9,692,236	10,530,361	12,228,549	13,629,267
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**10,997,210**	**9,246,970**	**9,706,850**	**10,780,150**	**12,283,630**	**14,274,390**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.09	0.09	0.09	0.06	0.07	0.07
30. COAL	7.27	0.50	0.00	1.26	0.18	2.57
31. NATURAL GAS	86.89	91.83	91.39	89.18	90.71	90.26
32. SOLAR	5.75	7.58	8.52	9.50	9.04	7.10
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)	127.51	127.47	127.51	127.45	127.52	127.49
37. COAL ($/TON)	76.89	71.68	0.00	77.72	77.26	76.16
38. NATURAL GAS ($/MCF)	4.26	4.22	4.04	3.63	3.58	3.58
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 ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	21.74	21.74	21.74	21.74	21.74	21.74
43. COAL	3.42	3.18	0.00	3.45	3.43	3.38
44. NATURAL GAS	4.15	4.11	3.94	3.54	3.49	3.51
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**4.08**	**4.12**	**3.97**	**3.56**	**3.51**	**3.52**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	11,005	11,008	11,005	11,001	10,999	10,998
50. COAL	12,699	13,111	0	12,279	12,435	12,574
51. NATURAL GAS	7,262	7,560	7,405	7,584	7,549	7,745
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**7,244**	**7,018**	**6,777**	**6,924**	**6,879**	**7,322**
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	23.93	23.93	23.93	23.92	23.91	23.91
57. COAL	4.34	4.17	0.00	4.24	4.27	4.26
58. NATURAL GAS	3.01	3.10	2.92	2.69	2.63	2.72
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**2.96**	**2.89**	**2.69**	**2.46**	**2.41**	**2.58**

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

SCHEDULE E3

		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	TOTAL
	FUEL COST OF SYSTEM NET GENERATION ($)							
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	317,757	317,757	307,507	179,379	225,505	317,757	3,444,078
3.	COAL	5,301,860	5,422,957	5,527,467	1,357,254	2,342,690	3,262,642	31,387,801
4.	NATURAL GAS	47,794,629	49,424,183	45,980,463	44,839,946	36,200,336	39,263,713	506,784,249
5.	SOLAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**53,414,246**	**55,164,897**	**51,815,437**	**46,376,579**	**38,768,531**	**42,844,112**	**541,616,128**
	SYSTEM NET GENERATION (MWH)							
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	1,328	1,328	1,286	750	943	1,328	14,397
10.	COAL	127,400	131,620	137,050	31,700	54,970	74,910	747,700
11.	NATURAL GAS	1,769,781	1,825,741	1,656,954	1,601,440	1,288,237	1,372,601	18,120,647
12.	SOLAR	135,120	130,800	112,660	112,340	89,200	76,430	1,413,420
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**2,033,629**	**2,089,489**	**1,907,950**	**1,746,230**	**1,433,350**	**1,525,269**	**20,296,164**
	UNITS OF FUEL BURNED							
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	2,492	2,492	2,412	1,407	1,769	2,492	27,013
17.	COAL (TON)	69,440	71,090	72,510	17,520	30,680	42,920	410,860
18.	NATURAL GAS (MCF)	13,150,682	13,636,082	12,579,822	12,163,571	9,657,212	10,059,302	134,495,743
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	14,614	14,614	14,143	8,250	10,371	14,614	158,399
23.	COAL	1,562,310	1,599,420	1,631,530	394,250	690,320	965,710	9,244,440
24.	NATURAL GAS	13,478,156	13,966,856	12,871,167	12,446,680	9,873,549	10,311,846	137,754,760
25.	SOLAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**15,055,080**	**15,580,890**	**14,516,840**	**12,849,180**	**10,574,240**	**11,292,170**	**147,157,599**
	GENERATION MIX (% MWH)							
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.07	0.06	0.07	0.04	0.07	0.09	0.07
30.	COAL	6.26	6.30	7.19	1.82	3.83	4.91	3.69
31.	NATURAL GAS	87.03	87.38	86.84	91.71	89.88	89.99	89.28
32.	SOLAR	6.64	6.26	5.90	6.43	6.22	5.01	6.96
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)	127.51	127.51	127.49	127.49	127.48	127.51	127.50
37.	COAL ($/TON)	76.35	76.28	76.23	77.47	76.36	76.02	76.40
38.	NATURAL GAS ($/MCF)	3.63	3.62	3.66	3.69	3.75	3.90	3.77
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 ($/MMBTU)							
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	21.74	21.74	21.74	21.74	21.74	21.74	21.74
43.	COAL	3.39	3.39	3.39	3.44	3.39	3.38	3.40
44.	NATURAL GAS	3.55	3.54	3.57	3.60	3.67	3.81	3.68
45.	SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	**TOTAL ($/MMBTU)**	**3.55**	**3.54**	**3.57**	**3.61**	**3.67**	**3.79**	**3.68**
	BTU BURNED PER KWH (BTU/KWH)							
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	11,005	11,005	10,998	11,000	10,998	11,005	11,002
50.	COAL	12,263	12,152	11,905	12,437	12,558	12,892	12,364
51.	NATURAL GAS	7,616	7,650	7,768	7,772	7,664	7,513	7,602
52.	SOLAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**7,403**	**7,457**	**7,609**	**7,358**	**7,377**	**7,403**	**7,251**
	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	23.93	23.93	23.91	23.92	23.91	23.93	23.92
57.	COAL	4.16	4.12	4.03	4.28	4.26	4.36	4.20
58.	NATURAL GAS	2.70	2.71	2.77	2.80	2.81	2.86	2.80
59.	SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	**TOTAL (CENTS/KWH)**	**2.63**	**2.64**	**2.72**	**2.66**	**2.70**	**2.81**	**2.67**

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

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	220	21.1	-	21.1	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	2,920	20.4	-	20.4	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	170	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	9,860	19.2	-	19.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	10,220	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	12,320	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	8,190	18.4	-	18.4	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	7,510	18.6	-	18.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	5,470	20.1	-	20.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	6,520	17.9	-	17.9	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	11,540	20.7	-	20.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	12,320	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL (3)	**585.5**	**87,260**	**20.0**	**-**	**20.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**315**	**6,230**	**2.7**	**91.8**	**38.0**	**13,526**	**GAS**	**81,970**	**1,028,059**	**84,270.0**	**349,182**	**5.60**	**4.26**
15. BIG BEND #2 TOTAL	**350**	**6,810**	**2.6**	**91.8**	**36.7**	**12,070**	**GAS**	**79,960**	**1,028,014**	**82,200.0**	**340,620**	**5.00**	**4.26**
16. B.B.#3 (GAS)	355	14,410	5.5	-	-	-	GAS	156,190	1,027,979	160,560.0	665,350	4.62	4.26
17. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**355**	**14,410**	**5.5**	**92.1**	**56.4**	**11,142**		**-**	**-**	**160,560.0**	**665,350**	**4.62**	**-**
19. B.B.#4 (GAS)	195	5,820	4.0	-	-	-	GAS	71,860	1,027,971	73,870.0	306,115	5.26	4.26
20. B.B.#4 (COAL)	442	110,520	33.6	-	-	-	COAL	62,380	22,499,679	1,403,530.0	4,796,166	4.34	76.89
21. BIG BEND #4 TOTAL	**442**	**116,340**	**35.4**	**86.2**	**38.4**	**12,699**		**-**	**-**	**1,477,400.0**	**5,102,281**	**4.39**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	17,120	-	17,600.0	72,929	-	4.26
23. B.B.C.T.#4 TOTAL	**61**	**160**	**0.4**	**98.2**	**87.4**	**11,375**	**GAS**	**1,770**	**-**	**1,820.0**	**7,540**	**4.71**	**4.26**
24. BIG BEND STATION TOTAL	**1,523**	**143,950**	**12.7**	**90.5**	**39.6**	**12,548**	**-**	**-**	**-**	**1,806,250.0**	**6,537,902**	**4.54**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	230	15,680	9.2	-	77.5	8,399	GAS	128,110	1,028,023	131,700.0	545,733	3.48	4.26
27. POLK #1 TOTAL	**230**	**15,680**	**9.2**	**87.4**	**77.5**	**8,399**	**-**	**-**	**-**	**131,700.0**	**545,733**	**3.48**	**-**
28. POLK #2 ST DUCT FIRING	120	3,650	4.1	-	78.0	8,164	GAS	28,990	1,027,941	29,800.0	123,494	3.38	4.26
29. POLK #2 ST W/O DUCT FIRING	360	685,581	-	-	-	-		4,615,322	1,028,010	4,744,595.7	19,660,700	2.87	4.26
30. POLK #2 ST TOTAL	**480**	**689,231**	**193.0**	**-**	**185.8**	**6,927**	**GAS**	**-**	**-**	**4,774,395.7**	**19,784,194**	**2.87**	**-**
31. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
33. POLK #2 TOTAL (4)	**180**	**664**	**0.5**	**-**	**80.2**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,879**	**23.93**	**-**
34. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
36. POLK #3 TOTAL (4)	**180**	**664**	**0.5**	**-**	**80.2**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,878**	**23.93**	**-**
37. POLK #4 CT (GAS) TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,200**	**690,559**	**77.3**	**97.2**	**184.6**	**6,935**	**-**	**-**	**-**	**4,789,009.9**	**20,101,951**	**2.91**	**-**
40. POLK STATION TOTAL	**1,430**	**706,239**	**66.4**	**95.6**	**173.7**	**6,967**	**-**	**-**	**-**	**4,920,709.9**	**20,647,684**	**2.92**	**-**
41. BAYSIDE #1	792	416,470	70.7	97.2	72.7	7,238	GAS	2,932,460	1,028,000	3,014,570.0	12,491,917	3.00	4.26
42. BAYSIDE #2	1,047	163,620	21.0	96.8	45.2	7,626	GAS	1,213,820	1,027,986	1,247,790.0	5,170,722	3.16	4.26
43. BAYSIDE #3	61	190	0.4	98.6	77.9	12,000	GAS	2,220	1,027,027	2,280.0	9,457	4.98	4.26
44. BAYSIDE #4	61	170	0.4	98.6	69.7	12,412	GAS	2,050	1,029,268	2,110.0	8,733	5.14	4.26
45. BAYSIDE #5	61	50	0.1	98.6	82.0	10,600	GAS	520	1,019,231	530.0	2,215	4.43	4.26
46. BAYSIDE #6	61	250	0.6	98.6	82.0	11,880	GAS	2,900	1,024,138	2,970.0	12,354	4.94	4.26
47. BAYSIDE STATION TOTAL	**2,083**	**580,750**	**37.5**	**97.2**	**62.1**	**7,353**	**GAS**	**4,153,970**	**1,027,992**	**4,270,250.0**	**17,695,398**	**3.05**	**4.26**
48. SYSTEM TOTAL	**5,622**	**1,518,199**	**36.3**	**84.9**	**95.5**	**7,244**	**-**	**-**	**-**	**10,997,209.9**	**44,880,984**	**2.96**	**-**

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: FEBRUARY 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	230	23.6	-	23.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	3,230	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	170	17.4	-	17.4	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	11,650	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	12,070	23.8	-	23.8	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	13,700	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	9,680	23.3	-	23.3	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	8,860	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	6,000	23.6	-	23.6	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	7,700	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	12,820	24.6	-	24.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	13,710	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**99,820**	**24.5**	**-**	**24.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**315**	**0**	**0.0**	**91.8**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
15. BIG BEND #2 TOTAL	**350**	**6,570**	**2.7**	**91.8**	**36.1**	**12,139**	**GAS**	**77,570**	**1,028,104**	**79,750.0**	**327,094**	**4.98**	**4.22**
16. B.B.#3 (GAS)	355	120,370	48.7	-	-	-	GAS	1,311,200	1,028,005	1,347,920.0	5,529,010	4.59	4.22
17. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**355**	**120,370**	**48.7**	**92.1**	**55.0**	**11,198**		**-**	**-**	**1,347,920.0**	**5,529,010**	**4.59**	**-**
19. B.B.#4 (GAS)	195	350	0.3	-	-	-	GAS	4,420	1,027,149	4,540.0	18,638	5.33	4.22
20. B.B.#4 (COAL)	442	6,580	2.1	-	-	-	COAL	3,830	22,524,804	86,270.0	274,531	4.17	71.68
21. BIG BEND #4 TOTAL	**442**	**6,930**	**2.3**	**8.9**	**34.8**	**13,104**		**-**	**-**	**90,810.0**	**293,169**	**4.23**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	9,600	-	9,880.0	40,481	-	4.22
23. B.B.C.T.#4 TOTAL	**61**	**40**	**0.1**	**98.2**	**65.6**	**13,500**	**GAS**	**530**	**1,018,868**	**540.0**	**2,235**	**5.59**	**4.22**
24. BIG BEND STATION TOTAL	**1,523**	**133,910**	**12.6**	**68.1**	**52.2**	**11,344**	**-**	**-**	**-**	**1,519,020.0**	**6,191,989**	**4.62**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	230	10,530	6.6	-	77.6	8,378	GAS	85,810	1,028,085	88,220.0	361,840	3.44	4.22
27. POLK #1 TOTAL	**230**	**10,530**	**6.6**	**67.6**	**77.6**	**8,378**	**-**	**-**	**-**	**88,220.0**	**361,840**	**3.44**	**-**
28. POLK #2 ST DUCT FIRING	120	5,660	6.8	-	72.6	8,177	GAS	45,030	1,027,759	46,280.0	189,881	3.35	4.22
29. POLK #2 ST W/O DUCT FIRING	360	629,797	-	-	-	-		4,239,942	1,028,009	4,358,698.6	17,878,800	2.84	4.22
30. POLK #2 ST TOTAL	**480**	**635,457**	**190.2**	**-**	**177.9**	**6,932**	**GAS**	**-**	**-**	**4,404,978.6**	**18,068,681**	**2.84**	**-**
31. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	187	621	0.5	-	80.2	11,008	LGT OIL	1,166	5,862,521	6,835.7	148,628	23.93	127.47
33. POLK #2 TOTAL [4]	**180**	**621**	**0.5**	**-**	**80.2**	**11,008**	**-**	**-**	**-**	**6,835.7**	**148,628**	**23.93**	**-**
34. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	187	621	0.5	-	80.2	11,008	LGT OIL	1,166	5,862,521	6,835.7	148,629	23.93	127.47
36. POLK #3 TOTAL [4]	**180**	**621**	**0.5**	**-**	**80.2**	**11,008**	**-**	**-**	**-**	**6,835.7**	**148,629**	**23.93**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,200**	**636,699**	**76.2**	**97.2**	**176.9**	**6,940**	**-**	**-**	**-**	**4,418,650.0**	**18,365,938**	**2.88**	**-**
40. POLK STATION TOTAL	**1,430**	**647,229**	**65.0**	**92.4**	**169.6**	**6,963**	**-**	**-**	**-**	**4,506,870.0**	**18,727,778**	**2.89**	**-**
41. BAYSIDE #1	792	327,030	59.3	93.9	66.5	7,278	GAS	2,315,450	1,027,999	2,380,280.0	9,763,688	2.99	4.22
42. BAYSIDE #2	1,047	109,180	15.0	56.7	43.1	7,658	GAS	813,290	1,028,010	836,070.0	3,429,446	3.14	4.22
43. BAYSIDE #3	61	50	0.1	98.6	82.0	12,600	GAS	610	1,032,787	630.0	2,572	5.14	4.22
44. BAYSIDE #4	61	50	0.1	98.6	82.0	12,600	GAS	610	1,032,787	630.0	2,572	5.14	4.22
45. BAYSIDE #5	61	230	0.5	98.6	75.4	12,348	GAS	2,760	1,028,986	2,840.0	11,638	5.06	4.22
46. BAYSIDE #6	61	50	0.1	98.6	82.0	12,600	GAS	610	1,032,787	630.0	2,572	5.14	4.22
47. BAYSIDE STATION TOTAL	**2,083**	**436,590**	**30.1**	**75.8**	**58.5**	**7,378**	**GAS**	**3,133,330**	**1,028,005**	**3,221,080.0**	**13,212,488**	**3.03**	**4.22**
48. SYSTEM TOTAL	**5,622**	**1,317,549**	**33.7**	**70.0**	**103.8**	**7,018**	**-**	**-**	**-**	**9,246,970.0**	**38,132,255**	**2.89**	**-**

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 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	280	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,130	28.9	-	28.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	240	23.0	-	23.0	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	13,350	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	13,850	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	17,510	32.3	-	32.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	11,150	25.1	-	25.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	10,210	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	8,360	30.8	-	30.8	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	8,850	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	16,580	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	17,520	31.6	-	31.6	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL (3)	**585.5**	**122,030**	**28.0**	**-**	**28.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**315**	**5,740**	**2.4**	**38.5**	**38.0**	**13,535**	**GAS**	**75,580**	**1,027,917**	**77,690.0**	**305,244**	**5.32**	**4.04**
15. BIG BEND #2 TOTAL	**350**	**19,340**	**7.4**	**91.8**	**38.4**	**11,932**	**GAS**	**224,470**	**1,028,022**	**230,760.0**	**906,565**	**4.69**	**4.04**
16. B.B.#3 (GAS)	355	41,100	15.6	-	-	-	GAS	450,090	1,027,994	462,690.0	1,817,775	4.42	4.04
17. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**355**	**41,100**	**15.6**	**92.1**	**53.6**	**11,258**		**-**	**-**	**462,690.0**	**1,817,775**	**4.42**	**-**
19. B.B.#4 (GAS)	195	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
20. B.B.#4 (COAL)	442	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #4 TOTAL	**442**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	31,310	-	32,190.0	126,451	-	4.04
23. B.B.C.T.#4 TOTAL	**61**	**340**	**0.7**	**44.3**	**92.9**	**11,294**	**GAS**	**3,730**	**1,029,491**	**3,840.0**	**15,064**	**4.43**	**4.04**
24. BIG BEND STATION TOTAL	**1,523**	**66,520**	**5.9**	**52.3**	**46.8**	**11,650**	**-**	**-**	**-**	**774,980.0**	**3,171,100**	**4.77**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	230	23,380	13.7	-	80.7	8,381	GAS	190,590	1,028,071	195,940.0	769,734	3.29	4.04
27. POLK #1 TOTAL	**230**	**23,380**	**13.7**	**93.4**	**80.7**	**8,381**	**-**	**-**	**-**	**195,940.0**	**769,734**	**3.29**	**-**
28. POLK #2 ST DUCT FIRING	120	9,210	10.3	-	77.5	8,173	GAS	73,220	1,027,998	75,270.0	295,713	3.21	4.04
29. POLK #2 ST W/O DUCT FIRING	360	686,231	-	-	-	-		4,621,002	1,028,010	4,750,435.7	18,662,805	2.72	4.04
30. POLK #2 ST TOTAL	**480**	**695,441**	**194.7**	**-**	**174.6**	**6,939**	**GAS**	**-**	**-**	**4,825,705.7**	**18,958,518**	**2.73**	**-**
31. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
33. POLK #2 TOTAL (4)	**180**	**664**	**0.5**	**-**	**80.2**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,879**	**23.93**	**-**
34. POLK #3 CT (GAS)	180	140	0.1	-	77.8	11,500	GAS	1,570	1,025,478	1,610.0	6,341	4.53	4.04
35. POLK #3 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
36. POLK #3 TOTAL (4)	**180**	**804**	**0.6**	**-**	**79.8**	**11,091**	**-**	**-**	**-**	**8,917.1**	**165,219**	**20.55**	**-**
37. POLK #4 CT (GAS) TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,200**	**696,909**	**78.1**	**97.2**	**173.4**	**6,948**	**-**	**-**	**-**	**4,841,929.9**	**19,282,616**	**2.77**	**-**
40. POLK STATION TOTAL	**1,430**	**720,289**	**67.7**	**96.6**	**161.3**	**6,994**	**-**	**-**	**-**	**5,037,869.9**	**20,052,350**	**2.78**	**-**
41. BAYSIDE #1	792	246,790	41.9	62.7	68.6	7,264	GAS	1,743,880	1,027,995	1,792,700.0	7,042,995	2.85	4.04
42. BAYSIDE #2	1,047	272,720	35.0	96.8	51.4	7,543	GAS	2,001,000	1,027,996	2,057,020.0	8,081,423	2.96	4.04
43. BAYSIDE #3	61	880	1.9	79.5	96.2	11,352	GAS	9,720	1,027,778	9,990.0	39,256	4.46	4.04
44. BAYSIDE #4	61	580	1.3	79.5	95.1	11,345	GAS	6,410	1,026,521	6,580.0	25,888	4.46	4.04
45. BAYSIDE #5	61	1,350	3.0	95.4	96.2	11,200	GAS	14,710	1,027,872	15,120.0	59,409	4.40	4.04
46. BAYSIDE #6	61	1,120	2.5	98.6	96.6	11,241	GAS	12,250	1,027,755	12,590.0	49,474	4.42	4.04
47. BAYSIDE STATION TOTAL	**2,083**	**523,440**	**33.8**	**82.8**	**58.5**	**7,439**	**GAS**	**3,787,970**	**1,027,991**	**3,894,000.0**	**15,298,445**	**2.92**	**4.04**
48. SYSTEM TOTAL	**5,622**	**1,432,279**	**34.2**	**69.4**	**106.7**	**6,777**	**-**	**-**	**-**	**9,706,849.9**	**38,521,895**	**2.69**	**-**

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: APRIL 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	270	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,690	33.9	-	33.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	270	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	17,410	35.1	-	35.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	18,140	34.6	-	34.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	19,730	37.6	-	37.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	14,630	34.0	-	34.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	13,360	34.1	-	34.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	9,270	35.3	-	35.3	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	11,650	33.1	-	33.1	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	18,800	34.9	-	34.9	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	19,740	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**147,960**	**35.1**	**-**	**35.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**6,390**	**2.9**	**39.8**	**43.6**	**13,188**	**GAS**	**81,970**	**1,028,059**	**84,270.0**	**297,782**	**4.66**	**3.63**
15. BIG BEND #2 TOTAL	**340**	**15,610**	**6.4**	**36.7**	**43.3**	**11,734**	**GAS**	**178,180**	**1,027,949**	**183,160.0**	**647,296**	**4.15**	**3.63**
16. B.B.#3 (GAS)	345	40,330	16.2	-	-	-	GAS	436,800	1,027,999	449,030.0	1,586,817	3.93	3.63
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**40,330**	**16.2**	**92.1**	**60.6**	**11,134**		**-**	**-**	**449,030.0**	**1,586,817**	**3.93**	**-**
19. B.B.#4 (GAS)	185	1,020	0.8	-	-	-	GAS	12,220	1,027,823	12,560.0	44,393	4.35	3.63
20. B.B.#4 (COAL)	437	19,440	6.2	-	-	-	COAL	10,610	22,498,586	238,710.0	824,594	4.24	77.72
21. BIG BEND #4 TOTAL	**437**	**20,460**	**6.5**	**48.8**	**44.6**	**12,281**		**-**	**-**	**251,270.0**	**868,987**	**4.25**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	25,040	-	25,750.0	90,966	-	3.63
23. B.B.C.T.#4 TOTAL	**56**	**1,310**	**3.2**	**85.1**	**86.6**	**11,870**	**GAS**	**15,130**	**1,027,759**	**15,550.0**	**54,965**	**4.20**	**3.63**
24. BIG BEND STATION TOTAL	**1,483**	**84,100**	**7.9**	**55.6**	**51.5**	**11,692**	**-**	**-**	**-**	**983,280.0**	**3,546,814**	**4.22**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	58,880	38.9	-	84.2	8,364	GAS	479,080	1,028,012	492,500.0	1,740,413	2.96	3.63
27. POLK #1 TOTAL	**220**	**58,880**	**37.2**	**93.4**	**84.2**	**8,364**	**-**	**-**	**-**	**492,500.0**	**1,740,413**	**2.96**	**-**
28. POLK #2 ST DUCT FIRING	120	7,790	9.0	-	55.5	8,268	GAS	62,660	1,027,929	64,410.0	227,633	2.92	3.63
29. POLK #2 ST W/O DUCT FIRING	341	396,823	-	-	-	-		2,721,292	1,028,012	2,797,521.4	9,885,972	2.49	3.63
30. POLK #2 ST TOTAL	**461**	**404,613**	**121.9**	**-**	**124.8**	**7,073**	**GAS**	**-**	**-**	**2,861,931.4**	**10,113,605**	**2.50**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	493	0.4	-	94.4	10,997	LGT OIL	925	5,860,973	5,421.4	117,891	23.91	127.45
33. POLK #2 TOTAL [4]	**150**	**493**	**0.5**	**-**	**94.4**	**10,997**	**-**	**-**	**-**	**5,421.4**	**117,891**	**23.91**	**-**
34. POLK #3 CT (GAS)	150	4,940	4.6	-	94.1	11,719	GAS	56,320	1,027,876	57,890.0	204,601	4.14	3.63
35. POLK #3 CT (OIL)	159	514	0.4	-	94.3	11,006	LGT OIL	965	5,862,280	5,657.1	122,990	23.93	127.45
36. POLK #3 TOTAL [4]	**150**	**5,454**	**5.1**	**-**	**94.1**	**11,651**	**-**	**-**	**-**	**63,547.1**	**327,591**	**6.01**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**2,990**	**2.8**	**-**	**94.9**	**11,702**	**GAS**	**34,040**	**1,027,908**	**34,990.0**	**123,661**	**4.14**	**3.63**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**1,340**	**1.2**	**-**	**99.3**	**11,560**	**GAS**	**15,070**	**1,027,870**	**15,490.0**	**54,747**	**4.09**	**3.63**
39. POLK #2 CC TOTAL	**1,061**	**414,890**	**54.3**	**76.5**	**122.1**	**7,186**	**-**	**-**	**-**	**2,981,379.9**	**10,737,495**	**2.59**	**-**
40. POLK STATION TOTAL	**1,281**	**473,770**	**51.4**	**79.4**	**110.7**	**7,332**	**-**	**-**	**-**	**3,473,879.9**	**12,477,908**	**2.63**	**-**
41. BAYSIDE #1	701	408,440	80.9	97.2	83.1	7,313	GAS	2,905,490	1,027,999	2,986,840.0	10,555,132	2.58	3.63
42. BAYSIDE #2	929	435,400	65.1	96.8	66.9	7,471	GAS	3,164,090	1,027,999	3,252,680.0	11,494,579	2.64	3.63
43. BAYSIDE #3	56	1,880	4.7	98.6	93.3	11,686	GAS	21,380	1,027,596	21,970.0	77,670	4.13	3.63
44. BAYSIDE #4	56	1,360	3.4	98.6	97.1	11,537	GAS	15,260	1,028,178	15,690.0	55,437	4.08	3.63
45. BAYSIDE #5	56	2,170	5.4	82.2	92.3	11,631	GAS	24,550	1,028,106	25,240.0	89,186	4.11	3.63
46. BAYSIDE #6	56	1,760	4.4	78.9	92.4	11,688	GAS	20,010	1,027,986	20,570.0	72,693	4.13	3.63
47. BAYSIDE STATION TOTAL	**1,854**	**851,010**	**63.8**	**96.1**	**74.0**	**7,430**	**GAS**	**6,150,780**	**1,027,998**	**6,322,990.0**	**22,344,697**	**2.63**	**3.63**
48. SYSTEM TOTAL	**5,204**	**1,556,840**	**41.6**	**69.6**	**96.5**	**6,924**	**-**	**-**	**-**	**10,780,149.9**	**38,369,419**	**2.46**	**-**

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. 20190001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 13 OF 30

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

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	290	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	5,060	35.4	-	35.4	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	290	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	19,560	38.2	-	38.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	20,360	37.5	-	37.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	20,540	37.9	-	37.9	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	16,380	36.9	-	36.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	14,940	36.9	-	36.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	10,090	37.2	-	37.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	13,020	35.8	-	35.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	20,290	36.5	-	36.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	20,560	37.1	-	37.1	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL (3)	**585.5**	**161,380**	**37.0**	**-**	**37.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**18,090**	**8.0**	**91.8**	**54.4**	**12,362**	**GAS**	**217,530**	**1,027,996**	**223,620.0**	**777,896**	**4.30**	**3.58**
15. BIG BEND #2 TOTAL	**340**	**9,620**	**3.8**	**41.5**	**50.5**	**11,289**	**GAS**	**105,640**	**1,028,020**	**108,600.0**	**377,773**	**3.93**	**3.58**
16. B.B.#3 (GAS)	345	46,340	18.1	-	-	-	GAS	500,300	1,027,983	514,300.0	1,789,093	3.86	3.58
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**46,340**	**18.1**	**65.3**	**62.2**	**11,098**		**-**	**-**	**514,300.0**	**1,789,093**	**3.86**	**-**
19. B.B.#4 (GAS)	185	180	0.1	-	-	-	GAS	2,120	1,028,302	2,180.0	7,581	4.21	3.58
20. B.B.#4 (COAL)	437	3,330	1.0	-	-	-	COAL	1,840	22,505,435	41,410.0	142,161	4.27	77.26
21. BIG BEND #4 TOTAL	**437**	**3,510**	**1.1**	**86.2**	**42.3**	**12,419**		**-**	**-**	**43,590.0**	**149,742**	**4.27**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	31,310	-	32,190.0	111,966	-	3.58
23. B.B.C.T.#4 TOTAL	**56**	**990**	**2.4**	**98.2**	**88.4**	**11,778**	**GAS**	**11,340**	**1,028,219**	**11,660.0**	**40,552**	**4.10**	**3.58**
24. BIG BEND STATION TOTAL	**1,483**	**78,550**	**7.1**	**72.7**	**58.1**	**11,480**	**-**	**-**	**-**	**901,770.0**	**3,247,022**	**4.13**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	69,870	44.7	-	86.4	8,356	GAS	567,930	1,028,014	583,840.0	2,030,940	2.91	3.58
27. POLK #1 TOTAL	**220**	**69,870**	**42.7**	**93.4**	**86.4**	**8,356**	**-**	**-**	**-**	**583,840.0**	**2,030,940**	**2.91**	**-**
28. POLK #2 ST DUCT FIRING	120	21,010	23.5	-	73.9	8,272	GAS	169,070	1,027,977	173,800.0	604,601	2.88	3.58
29. POLK #2 ST W/O DUCT FIRING	341	527,257	-	-	-	-		3,625,582	1,028,011	3,727,138.6	12,965,226	2.46	3.58
30. POLK #2 ST TOTAL	**461**	**548,267**	**159.9**	**-**	**122.7**	**7,115**	**GAS**	**-**	**-**	**3,900,938.6**	**13,569,827**	**2.48**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,894	23.93	127.52
33. POLK #2 TOTAL (4)	**150**	**664**	**0.6**	**-**	**94.3**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,894**	**23.93**	**-**
34. POLK #3 CT (GAS)	150	120	0.1	-	80.0	13,167	GAS	1,540	1,025,974	1,580.0	5,507	4.59	3.58
35. POLK #3 CT (OIL)	159	579	0.5	-	94.4	10,992	LGT OIL	1,085	5,865,714	6,364.3	138,363	23.90	127.52
36. POLK #3 TOTAL (4)	**150**	**699**	**0.6**	**-**	**91.6**	**11,365**	**-**	**-**	**-**	**7,944.3**	**143,870**	**20.58**	**-**
37. POLK #4 CT (GAS) TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**549,630**	**69.6**	**88.2**	**122.5**	**7,125**	**-**	**-**	**-**	**3,916,190.0**	**13,872,591**	**2.52**	**-**
40. POLK STATION TOTAL	**1,281**	**619,500**	**65.0**	**89.1**	**112.3**	**7,264**	**-**	**-**	**-**	**4,500,030.0**	**15,903,531**	**2.57**	**-**
41. BAYSIDE #1	701	431,760	82.8	97.2	85.1	7,305	GAS	3,068,010	1,028,002	3,153,920.0	10,971,326	2.54	3.58
42. BAYSIDE #2	929	482,530	69.8	96.8	71.6	7,437	GAS	3,490,900	1,027,996	3,588,630.0	12,483,597	2.59	3.58
43. BAYSIDE #3	56	2,690	6.5	98.6	94.2	11,584	GAS	30,320	1,027,704	31,160.0	108,426	4.03	3.58
44. BAYSIDE #4	56	1,580	3.8	98.6	94.0	11,576	GAS	17,790	1,028,106	18,290.0	63,618	4.03	3.58
45. BAYSIDE #5	56	4,480	10.8	98.6	94.1	11,545	GAS	50,320	1,027,822	51,720.0	179,946	4.02	3.58
46. BAYSIDE #6	56	3,300	7.9	98.6	93.5	11,548	GAS	37,070	1,028,055	38,110.0	132,564	4.02	3.58
47. BAYSIDE STATION TOTAL	**1,854**	**926,340**	**67.2**	**97.2**	**77.6**	**7,429**	**GAS**	**6,694,410**	**1,027,996**	**6,881,830.0**	**23,939,477**	**2.58**	**3.58**
48. SYSTEM TOTAL	**5,204**	**1,785,770**	**46.1**	**77.3**	**105.4**	**6,879**	**-**	**-**	**-**	**12,283,630.0**	**43,090,030**	**2.41**	**-**

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

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

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

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	250	24.8	-	24.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,490	32.5	-	32.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	270	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	16,920	34.1	-	34.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	17,560	33.5	-	33.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	17,620	33.6	-	33.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	14,130	32.9	-	32.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	12,890	32.9	-	32.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	8,750	33.3	-	33.3	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	11,210	31.8	-	31.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	16,680	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	17,650	32.9	-	32.9	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL (3)	**585.5**	**138,420**	**32.8**	**-**	**32.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**36,800**	**16.8**	**91.8**	**45.5**	**13,011**	**GAS**	**465,770**	**1,027,997**	**478,810.0**	**1,667,331**	**4.53**	**3.58**
15. BIG BEND #2 TOTAL	**340**	**52,400**	**21.4**	**91.8**	**49.7**	**11,372**	**GAS**	**579,630**	**1,028,018**	**595,870.0**	**2,074,920**	**3.96**	**3.58**
16. B.B.#3 (GAS)	345	58,990	23.7	-	-	-	GAS	635,610	1,027,989	653,400.0	2,275,313	3.86	3.58
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**58,990**	**23.7**	**76.7**	**62.4**	**11,076**		**-**	**-**	**653,400.0**	**2,275,313**	**3.86**	**-**
19. B.B.#4 (GAS)	185	2,640	2.0	-	-	-	GAS	32,300	1,028,173	33,210.0	115,625	4.38	3.58
20. B.B.#4 (COAL)	437	50,180	15.9	-	-	-	COAL	28,040	22,502,853	630,980.0	2,135,479	4.26	76.16
21. BIG BEND #4 TOTAL	**437**	**52,820**	**16.8**	**86.2**	**41.3**	**12,575**		**-**	**-**	**664,190.0**	**2,251,104**	**4.26**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	93,510	-	96,120.0	334,741	-	3.58
23. B.B.C.T.#4 TOTAL	**56**	**1,880**	**4.7**	**98.2**	**95.9**	**11,495**	**GAS**	**21,030**	**1,027,580**	**21,610.0**	**75,282**	**4.00**	**3.58**
24. BIG BEND STATION TOTAL	**1,483**	**202,890**	**19.0**	**86.9**	**49.6**	**11,897**	**-**	**-**	**-**	**2,413,880.0**	**8,678,691**	**4.28**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	81,100	53.6	-	87.8	8,321	GAS	656,430	1,028,015	674,820.0	2,349,843	2.90	3.58
27. POLK #1 TOTAL	**220**	**81,100**	**51.2**	**93.4**	**87.8**	**8,321**	**-**	**-**	**-**	**674,820.0**	**2,349,843**	**2.90**	**-**
28. POLK #2 ST DUCT FIRING	120	30,210	35.0	-	88.3	8,275	GAS	243,190	1,028,003	250,000.0	870,555	2.88	3.58
29. POLK #2 ST W/O DUCT FIRING	341	555,784	-	-	-	-		3,837,122	1,028,009	3,944,597.1	13,735,867	2.47	3.58
30. POLK #2 ST TOTAL	**461**	**585,994**	**176.5**	**-**	**127.8**	**7,158**	**GAS**	**-**	**-**	**4,194,597.1**	**14,606,422**	**2.49**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	643	0.6	-	94.4	10,998	LGT OIL	1,206	5,863,516	7,071.4	153,754	23.91	127.49
33. POLK #2 TOTAL (4)	**150**	**643**	**0.6**	**-**	**94.4**	**10,998**	**-**	**-**	**-**	**7,071.4**	**153,754**	**23.91**	**-**
34. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	159	643	0.6	-	94.4	10,998	LGT OIL	1,206	5,863,516	7,071.4	153,753	23.91	127.49
36. POLK #3 TOTAL (4)	**150**	**643**	**0.6**	**-**	**94.4**	**10,998**	**-**	**-**	**-**	**7,071.4**	**153,753**	**23.91**	**-**
37. POLK #4 CT (GAS) TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**587,280**	**76.9**	**98.2**	**127.5**	**7,166**	**-**	**-**	**-**	**4,208,739.9**	**14,913,929**	**2.54**	**-**
40. POLK STATION TOTAL	**1,281**	**668,380**	**72.5**	**97.3**	**115.4**	**7,307**	**-**	**-**	**-**	**4,883,559.9**	**17,263,772**	**2.58**	**-**
41. BAYSIDE #1	701	425,680	84.3	97.2	87.0	7,297	GAS	3,021,730	1,028,001	3,106,340.0	10,816,982	2.54	3.58
42. BAYSIDE #2	929	498,760	74.6	96.8	76.6	7,406	GAS	3,593,010	1,028,002	3,693,620.0	12,862,011	2.58	3.58
43. BAYSIDE #3	56	3,420	8.5	98.6	96.9	11,468	GAS	38,160	1,027,778	39,220.0	136,603	3.99	3.58
44. BAYSIDE #4	56	2,640	6.5	98.6	98.2	11,375	GAS	29,200	1,028,425	30,030.0	104,528	3.96	3.58
45. BAYSIDE #5	56	5,160	12.8	98.6	97.0	11,434	GAS	57,390	1,028,054	59,000.0	205,441	3.98	3.58
46. BAYSIDE #6	56	4,260	10.6	98.6	96.3	11,441	GAS	47,410	1,028,053	48,740.0	169,715	3.98	3.58
47. BAYSIDE STATION TOTAL	**1,854**	**939,920**	**70.4**	**97.2**	**81.3**	**7,423**	**GAS**	**6,786,900**	**1,028,002**	**6,976,950.0**	**24,295,280**	**2.58**	**3.58**
48. SYSTEM TOTAL	**5,204**	**1,949,610**	**52.0**	**83.3**	**100.4**	**7,322**	**-**	**-**	**-**	**14,274,389.9**	**50,237,743**	**2.58**	**-**

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: JULY 2020

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	240	23.0	-	23.0	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,340	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	260	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	16,400	32.0	-	32.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	17,010	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	17,410	32.1	-	32.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	13,690	30.8	-	30.8	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	12,500	30.9	-	30.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	8,520	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	10,850	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	16,450	29.6	-	29.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	17,450	31.5	-	31.5	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**135,120**	**31.0**	**-**	**31.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**6,110**	**2.7**	**91.8**	**41.7**	**13,365**	**GAS**	**79,440**	**1,027,946**	**81,660.0**	**288,715**	**4.73**	**3.63**
15. BIG BEND #2 TOTAL	**340**	**39,800**	**15.7**	**91.8**	**47.4**	**11,473**	**GAS**	**444,180**	**1,028,007**	**456,620.0**	**1,614,321**	**4.06**	**3.63**
16. B.B.#3 (GAS)	345	57,420	22.4	-	-	-	GAS	623,380	1,027,993	640,830.0	2,265,602	3.95	3.63
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**57,420**	**22.4**	**92.1**	**59.7**	**11,160**		**-**	**-**	**640,830.0**	**2,265,602**	**3.95**	**-**
19. B.B.#4 (GAS)	185	6,700	4.9	-	-	-	GAS	79,990	1,028,004	82,230.0	290,714	4.34	3.63
20. B.B.#4 (COAL)	437	127,400	39.2	-	-	-	COAL	69,440	22,498,704	1,562,310.0	5,301,860	4.16	76.35
21. BIG BEND #4 TOTAL	**437**	**134,100**	**41.2**	**86.2**	**44.8**	**12,264**		**-**	**-**	**1,644,540.0**	**5,592,574**	**4.17**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	39,660	-	40,770.0	144,140	-	3.63
23. B.B.C.T.#4 TOTAL	**56**	**1,260**	**3.0**	**98.2**	**83.3**	**12,167**	**GAS**	**14,920**	**1,027,480**	**15,330.0**	**54,225**	**4.30**	**3.63**
24. BIG BEND STATION TOTAL	**1,483**	**238,690**	**21.6**	**90.5**	**48.3**	**11,894**	**-**	**-**	**-**	**2,838,980.0**	**9,959,578**	**4.17**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	69,360	44.4	-	90.5	8,328	GAS	561,890	1,027,995	577,620.0	2,042,124	2.94	3.63
27. POLK #1 TOTAL	**220**	**69,360**	**42.4**	**93.4**	**90.5**	**8,328**	**-**	**-**	**-**	**577,620.0**	**2,042,124**	**2.94**	**-**
28. POLK #2 ST DUCT FIRING	120	30,810	34.5	-	90.4	8,276	GAS	248,050	1,027,978	254,990.0	901,509	2.93	3.63
29. POLK #2 ST W/O DUCT FIRING	341	579,401	-	-	-	-		4,002,322	1,028,010	4,114,425.7	14,545,975	2.51	3.63
30. POLK #2 ST TOTAL	**461**	**610,211**	**177.9**	**-**	**130.0**	**7,160**	**GAS**	**-**	**-**	**4,369,415.7**	**15,447,484**	**2.53**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
33. POLK #2 TOTAL [4]	**150**	**664**	**0.6**	**-**	**94.3**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,879**	**23.93**	**-**
34. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
36. POLK #3 TOTAL [4]	**150**	**664**	**0.6**	**-**	**94.3**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,878**	**23.93**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**611,539**	**77.5**	**98.1**	**129.7**	**7,169**	**-**	**-**	**-**	**4,384,029.9**	**15,765,241**	**2.58**	**-**
40. POLK STATION TOTAL	**1,281**	**680,899**	**71.4**	**97.3**	**119.4**	**7,287**	**-**	**-**	**-**	**4,961,649.9**	**17,807,365**	**2.62**	**-**
41. BAYSIDE #1	701	444,310	85.2	97.2	87.4	7,295	GAS	3,153,090	1,028,001	3,241,380.0	11,459,540	2.58	3.63
42. BAYSIDE #2	929	521,610	75.5	96.8	77.4	7,398	GAS	3,753,930	1,028,000	3,859,040.0	13,643,223	2.62	3.63
43. BAYSIDE #3	56	3,030	7.3	98.6	85.9	11,888	GAS	35,030	1,028,261	36,020.0	127,312	4.20	3.63
44. BAYSIDE #4	56	1,920	4.6	98.6	85.7	12,016	GAS	22,440	1,028,075	23,070.0	81,556	4.25	3.63
45. BAYSIDE #5	56	4,310	10.3	98.6	85.5	11,768	GAS	49,330	1,028,178	50,720.0	179,284	4.16	3.63
46. BAYSIDE #6	56	3,740	9.0	98.6	83.5	11,824	GAS	43,030	1,027,655	44,220.0	156,388	4.18	3.63
47. BAYSIDE STATION TOTAL	**1,854**	**978,920**	**71.0**	**97.2**	**81.8**	**7,411**	**GAS**	**7,056,850**	**1,028,001**	**7,254,450.0**	**25,647,303**	**2.62**	**3.63**
48. SYSTEM TOTAL	**5,204**	**2,033,629**	**52.5**	**84.4**	**98.8**	**7,403**	**-**	**-**	**-**	**15,055,079.9**	**53,414,246**	**2.63**	**-**

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: AUGUST 2020

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	250	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,250	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	250	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	15,830	30.9	-	30.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	16,410	30.3	-	30.3	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	16,830	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	13,220	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	12,080	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	8,380	30.9	-	30.9	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	10,470	28.8	-	28.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	15,940	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	16,890	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**130,800**	**30.0**	**-**	**30.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**21,240**	**9.4**	**91.8**	**52.4**	**12,485**	**GAS**	**257,960**	**1,028,028**	**265,190.0**	**934,980**	**4.40**	**3.62**
15. BIG BEND #2 TOTAL	**340**	**48,520**	**19.2**	**91.8**	**50.1**	**11,326**	**GAS**	**534,560**	**1,028,004**	**549,530.0**	**1,937,521**	**3.99**	**3.62**
16. B.B.#3 (GAS)	345	50,380	19.6	-	-	-	GAS	543,340	1,028,012	558,560.0	1,969,344	3.91	3.62
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**50,380**	**19.6**	**92.1**	**61.4**	**11,087**		**-**	**-**	**558,560.0**	**1,969,344**	**3.91**	**-**
19. B.B.#4 (GAS)	185	6,930	5.0	-	-	-	GAS	81,890	1,027,964	84,180.0	296,812	4.28	3.62
20. B.B.#4 (COAL)	437	131,620	40.5	-	-	-	COAL	71,090	22,498,523	1,599,420.0	5,422,957	4.12	76.28
21. BIG BEND #4 TOTAL	**437**	**138,550**	**42.6**	**86.2**	**46.3**	**12,152**		**-**	**-**	**1,683,600.0**	**5,719,769**	**4.13**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	49,680	-	51,070.0	180,066	-	3.62
23. B.B.C.T.#4 TOTAL	**56**	**1,900**	**4.6**	**98.2**	**91.7**	**11,584**	**GAS**	**21,410**	**1,028,024**	**22,010.0**	**77,601**	**4.08**	**3.62**
24. BIG BEND STATION TOTAL	**1,483**	**260,590**	**23.6**	**90.5**	**50.2**	**11,815**	**-**	**-**	**-**	**3,078,890.0**	**10,819,280**	**4.15**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	76,010	48.6	-	88.9	8,339	GAS	616,600	1,027,992	633,860.0	2,234,876	2.94	3.62
27. POLK #1 TOTAL	**220**	**76,010**	**46.4**	**93.4**	**88.9**	**8,339**	**-**	**-**	**-**	**633,860.0**	**2,234,876**	**2.94**	**-**
28. POLK #2 ST DUCT FIRING	120	30,420	34.1	-	88.6	8,275	GAS	244,870	1,027,974	251,720.0	887,535	2.92	3.62
29. POLK #2 ST W/O DUCT FIRING	341	577,821	-	-	-	-		3,989,402	1,028,010	4,101,145.7	14,459,647	2.50	3.62
30. POLK #2 ST TOTAL	**461**	**608,241**	**177.3**	**-**	**129.4**	**7,156**	**GAS**	**-**	**-**	**4,352,865.7**	**15,347,182**	**2.52**	**-**
31. POLK #2 CT (GAS)	150	1,050	0.9	-	100.0	11,486	GAS	11,730	1,028,133	12,060.0	42,515	4.05	3.62
32. POLK #2 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
33. POLK #2 TOTAL [4]	**150**	**1,714**	**1.5**	**-**	**97.7**	**11,299**	**-**	**-**	**-**	**19,367.1**	**201,394**	**11.75**	**-**
34. POLK #3 CT (GAS)	150	1,050	0.9	-	100.0	11,486	GAS	11,730	1,028,133	12,060.0	42,516	4.05	3.62
35. POLK #3 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
36. POLK #3 TOTAL [4]	**150**	**1,714**	**1.5**	**-**	**97.7**	**11,299**	**-**	**-**	**-**	**19,367.1**	**201,394**	**11.75**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**750**	**0.7**	**-**	**100.0**	**11,520**	**GAS**	**8,410**	**1,027,348**	**8,640.0**	**30,482**	**4.06**	**3.62**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**612,419**	**77.6**	**96.6**	**128.5**	**7,185**	**-**	**-**	**-**	**4,400,239.9**	**15,780,452**	**2.58**	**-**
40. POLK STATION TOTAL	**1,281**	**688,429**	**72.2**	**96.0**	**117.4**	**7,312**	**-**	**-**	**-**	**5,034,099.9**	**18,015,328**	**2.62**	**-**
41. BAYSIDE #1	701	450,090	86.3	97.2	88.6	7,291	GAS	3,192,080	1,028,001	3,281,460.0	11,569,742	2.57	3.62
42. BAYSIDE #2	929	545,740	79.0	96.8	81.3	7,376	GAS	3,915,520	1,028,001	4,025,160.0	14,191,860	2.60	3.62
43. BAYSIDE #3	56	2,990	7.2	98.6	90.5	11,645	GAS	33,880	1,027,745	34,820.0	122,799	4.11	3.62
44. BAYSIDE #4	56	2,410	5.8	98.6	89.7	11,743	GAS	27,540	1,027,596	28,300.0	99,819	4.14	3.62
45. BAYSIDE #5	56	4,480	10.8	98.6	89.9	11,616	GAS	50,620	1,028,052	52,040.0	183,473	4.10	3.62
46. BAYSIDE #6	56	3,960	9.5	98.6	89.5	11,646	GAS	44,860	1,028,087	46,120.0	162,596	4.11	3.62
47. BAYSIDE STATION TOTAL	**1,854**	**1,009,670**	**73.2**	**97.2**	**84.5**	**7,396**	**GAS**	**7,264,500**	**1,027,999**	**7,467,900.0**	**26,330,289**	**2.61**	**3.62**
48. SYSTEM TOTAL	**5,204**	**2,089,489**	**54.0**	**84.0**	**99.8**	**7,457**	**-**	**-**	**-**	**15,580,889.9**	**55,164,897**	**2.64**	**-**

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. 20190001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 17 OF 30

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

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	220	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	3,530	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	200	19.8	-	19.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	13,770	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	14,270	27.2	-	27.2	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	14,470	27.6	-	27.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	11,490	26.7	-	26.7	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	10,510	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	6,780	25.8	-	25.8	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	9,100	25.8	-	25.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	13,800	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	14,520	27.1	-	27.1	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL (3)	**585.5**	**112,660**	**26.7**	**-**	**26.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**28,050**	**12.8**	**91.8**	**52.3**	**12,484**	**GAS**	**340,640**	**1,028,006**	**350,180.0**	**1,245,072**	**4.44**	**3.66**
15. BIG BEND #2 TOTAL	**340**	**54,560**	**22.3**	**91.8**	**48.0**	**11,443**	**GAS**	**607,300**	**1,028,009**	**624,310.0**	**2,219,740**	**4.07**	**3.66**
16. B.B.#3 (GAS)	345	63,520	25.6	-	-	-	GAS	683,820	1,028,004	702,970.0	2,499,428	3.93	3.66
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**63,520**	**25.6**	**92.1**	**62.2**	**11,067**		**-**	**-**	**702,970.0**	**2,499,428**	**3.93**	**-**
19. B.B.#4 (GAS)	185	7,210	5.4	-	-	-	GAS	83,530	1,028,014	85,870.0	305,310	4.23	3.66
20. B.B.#4 (COAL)	437	137,050	43.6	-	-	-	COAL	72,510	22,500,759	1,631,530.0	5,527,467	4.03	76.23
21. BIG BEND #4 TOTAL	**437**	**144,260**	**45.8**	**86.2**	**49.8**	**11,905**		**-**	**-**	**1,717,400.0**	**5,832,777**	**4.04**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	59,270	-	60,940.0	216,638	-	3.66
23. B.B.C.T.#4 TOTAL	**56**	**2,600**	**6.4**	**98.2**	**92.9**	**11,608**	**GAS**	**29,360**	**1,027,929**	**30,180.0**	**107,314**	**4.13**	**3.66**
24. BIG BEND STATION TOTAL	**1,483**	**292,990**	**27.4**	**90.5**	**52.4**	**11,690**	**-**	**-**	**-**	**3,425,040.0**	**12,120,969**	**4.14**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	35,810	23.7	-	87.0	8,323	GAS	289,910	1,028,009	298,030.0	1,059,649	2.96	3.66
27. POLK #1 TOTAL	**220**	**35,810**	**22.6**	**40.5**	**87.0**	**8,323**	**-**	**-**	**-**	**298,030.0**	**1,059,649**	**2.96**	**-**
28. POLK #2 ST DUCT FIRING	120	26,560	30.7	-	71.2	8,275	GAS	213,800	1,027,970	219,780.0	781,460	2.94	3.66
29. POLK #2 ST W/O DUCT FIRING	341	482,874	-	-	-	-		3,305,412	1,028,013	3,398,007.1	12,081,600	2.50	3.66
30. POLK #2 ST TOTAL	**461**	**509,434**	**153.5**	**-**	**108.2**	**7,102**	**GAS**	**-**	**-**	**3,617,787.1**	**12,863,060**	**2.52**	**-**
31. POLK #2 CT (GAS)	150	1,500	1.4	-	100.0	11,453	GAS	16,720	1,027,512	17,180.0	61,112	4.07	3.66
32. POLK #2 CT (OIL)	159	643	0.6	-	94.4	10,998	LGT OIL	1,206	5,863,516	7,071.4	153,754	23.91	127.49
33. POLK #2 TOTAL (4)	**150**	**2,143**	**2.0**	**-**	**98.2**	**11,317**	**-**	**-**	**-**	**24,251.4**	**214,866**	**10.03**	**-**
34. POLK #3 CT (GAS)	150	1,500	1.4	-	100.0	11,400	GAS	16,640	1,027,644	17,100.0	60,821	4.05	3.66
35. POLK #3 CT (OIL)	159	643	0.6	-	94.4	10,998	LGT OIL	1,206	5,863,516	7,071.4	153,753	23.91	127.49
36. POLK #3 TOTAL (4)	**150**	**2,143**	**2.0**	**-**	**98.2**	**11,279**	**-**	**-**	**-**	**24,171.4**	**214,574**	**10.01**	**-**
37. POLK #4 CT (GAS) TOTAL (4)	**150**	**1,350**	**1.3**	**-**	**100.0**	**11,467**	**GAS**	**15,060**	**1,027,888**	**15,480.0**	**55,046**	**4.08**	**3.66**
38. POLK #5 CT (GAS) TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**515,070**	**67.4**	**74.6**	**107.9**	**7,148**	**-**	**-**	**-**	**3,681,689.9**	**13,347,546**	**2.59**	**-**
40. POLK STATION TOTAL	**1,281**	**550,880**	**59.7**	**68.7**	**104.6**	**7,224**	**-**	**-**	**-**	**3,979,719.9**	**14,407,195**	**2.62**	**-**
41. BAYSIDE #1	701	424,000	84.0	97.2	86.8	7,297	GAS	3,009,690	1,028,000	3,093,960.0	11,000,707	2.59	3.66
42. BAYSIDE #2	929	498,610	74.5	96.8	76.6	7,400	GAS	3,589,110	1,027,999	3,689,600.0	13,118,543	2.63	3.66
43. BAYSIDE #3	56	6,530	16.2	98.6	99.7	11,467	GAS	72,850	1,027,865	74,880.0	266,274	4.08	3.66
44. BAYSIDE #4	56	4,400	10.9	98.6	99.5	11,573	GAS	49,530	1,028,064	50,920.0	181,037	4.11	3.66
45. BAYSIDE #5	56	9,450	23.4	98.6	99.3	11,334	GAS	104,180	1,028,124	107,110.0	380,788	4.03	3.66
46. BAYSIDE #6	56	8,430	20.9	98.6	99.7	11,342	GAS	93,000	1,028,065	95,610.0	339,924	4.03	3.66
47. BAYSIDE STATION TOTAL	**1,854**	**951,420**	**71.3**	**97.2**	**81.4**	**7,475**	**GAS**	**6,918,360**	**1,028,001**	**7,112,080.0**	**25,287,273**	**2.66**	**3.66**
48. SYSTEM TOTAL	**5,204**	**1,907,950**	**50.9**	**77.3**	**92.7**	**7,609**	**-**	**-**	**-**	**14,516,839.9**	**51,815,437**	**2.72**	**-**

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: OCTOBER 2020

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) (2)	AS BURNED FUEL COST ($) (1)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	250	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	3,650	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	210	20.2	-	20.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	13,610	26.6	-	26.6	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	14,110	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	14,130	26.1	-	26.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	11,340	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	10,380	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	7,160	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	8,990	24.7	-	24.7	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	14,330	25.7	-	25.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	14,180	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL (3)	**585.5**	**112,340**	**25.8**	**-**	**25.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**14,770**	**6.5**	**91.8**	**52.1**	**12,521**	**GAS**	**179,890**	**1,028,017**	**184,930.0**	**663,149**	**4.49**	**3.69**
15. BIG BEND #2 TOTAL	**340**	**49,970**	**19.8**	**91.8**	**50.0**	**11,355**	**GAS**	**551,950**	**1,027,992**	**567,400.0**	**2,034,715**	**4.07**	**3.69**
16. B.B.#3 (GAS)	345	66,880	26.1	-	-	-	GAS	718,440	1,028,005	738,560.0	2,648,466	3.96	3.69
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**66,880**	**26.1**	**86.1**	**63.6**	**11,043**		**-**	**-**	**738,560.0**	**2,648,466**	**3.96**	**-**
19. B.B.#4 (GAS)	185	1,670	1.2	-	-	-	GAS	20,180	1,028,246	20,750.0	74,392	4.45	3.69
20. B.B.#4 (COAL)	437	31,700	9.8	-	-	-	COAL	17,520	22,502,854	394,250.0	1,357,254	4.28	77.47
21. BIG BEND #4 TOTAL	**437**	**33,370**	**10.3**	**86.2**	**42.7**	**12,436**		**-**	**-**	**415,000.0**	**1,431,646**	**4.29**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	55,940	-	57,490.0	206,218	-	3.69
23. B.B.C.T.#4 TOTAL	**56**	**3,500**	**8.4**	**98.2**	**97.7**	**11,446**	**GAS**	**38,970**	**1,027,970**	**40,060.0**	**143,660**	**4.10**	**3.69**
24. BIG BEND STATION TOTAL	**1,483**	**168,490**	**15.3**	**89.1**	**54.0**	**11,549**	**-**	**-**	**-**	**1,945,950.0**	**7,127,854**	**4.23**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	69,480	44.5	-	88.5	8,332	GAS	563,110	1,028,005	578,880.0	2,075,856	2.99	3.69
27. POLK #1 TOTAL	**220**	**69,480**	**42.4**	**81.4**	**88.5**	**8,332**	**-**	**-**	**-**	**578,880.0**	**2,075,856**	**2.99**	**-**
28. POLK #2 ST DUCT FIRING	120	18,370	20.6	-	66.3	8,277	GAS	147,900	1,027,992	152,040.0	545,220	2.97	3.69
29. POLK #2 ST W/O DUCT FIRING	341	409,700	-	-	-	-		2,806,381	1,028,007	2,884,980.0	10,345,479	2.53	3.69
30. POLK #2 ST TOTAL	**461**	**428,070**	**124.8**	**-**	**110.3**	**7,095**	**GAS**	**-**	**-**	**3,037,020.0**	**10,890,699**	**2.54**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	86	0.1	-	94.7	10,964	LGT OIL	161	5,856,522	942.9	20,526	23.87	127.49
33. POLK #2 TOTAL (4)	**150**	**86**	**0.1**	**-**	**94.7**	**10,964**	**-**	**-**	**-**	**942.9**	**20,526**	**23.87**	**-**
34. POLK #3 CT (GAS)	150	7,390	6.6	-	96.6	11,562	GAS	83,120	1,027,911	85,440.0	306,415	4.15	3.69
35. POLK #3 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,853	23.92	127.49
36. POLK #3 TOTAL (4)	**150**	**8,054**	**7.2**	**-**	**96.4**	**11,516**	**-**	**-**	**-**	**92,747.1**	**465,268**	**5.78**	**-**
37. POLK #4 CT (GAS) TOTAL (4)	**150**	**5,960**	**5.3**	**-**	**96.9**	**11,579**	**GAS**	**67,120**	**1,028,159**	**69,010.0**	**247,432**	**4.15**	**3.69**
38. POLK #5 CT (GAS) TOTAL (4)	**150**	**4,010**	**3.6**	**-**	**99.0**	**11,501**	**GAS**	**44,850**	**1,028,317**	**46,120.0**	**165,336**	**4.12**	**3.69**
39. POLK #2 CC TOTAL	**1,061**	**446,180**	**56.5**	**69.4**	**108.6**	**7,275**	**-**	**-**	**-**	**3,245,840.0**	**11,789,261**	**2.64**	**-**
40. POLK STATION TOTAL	**1,281**	**515,660**	**54.1**	**71.4**	**103.0**	**7,417**	**-**	**-**	**-**	**3,824,720.0**	**13,865,117**	**2.69**	**-**
41. BAYSIDE #1	701	437,940	84.0	97.2	86.4	7,300	GAS	3,110,040	1,028,000	3,197,120.0	11,464,892	2.62	3.69
42. BAYSIDE #2	929	490,860	71.0	96.8	74.5	7,419	GAS	3,542,490	1,027,997	3,641,670.0	13,059,081	2.66	3.69
43. BAYSIDE #3	56	4,810	11.5	98.6	97.6	11,511	GAS	53,860	1,028,036	55,370.0	198,550	4.13	3.69
44. BAYSIDE #4	56	3,620	8.7	98.6	97.9	11,528	GAS	40,590	1,028,086	41,730.0	149,632	4.13	3.69
45. BAYSIDE #5	56	6,620	15.9	98.6	98.5	11,391	GAS	73,370	1,027,804	75,410.0	270,472	4.09	3.69
46. BAYSIDE #6	56	5,890	14.1	98.6	99.2	11,411	GAS	65,370	1,028,147	67,210.0	240,981	4.09	3.69
47. BAYSIDE STATION TOTAL	**1,854**	**949,740**	**68.9**	**97.2**	**80.0**	**7,453**	**GAS**	**6,885,720**	**1,027,999**	**7,078,510.0**	**25,383,608**	**2.67**	**3.69**
48. SYSTEM TOTAL	**5,204**	**1,746,230**	**45.1**	**77.6**	**95.0**	**7,358**	**-**	**-**	**-**	**12,849,180.0**	**46,376,579**	**2.66**	**-**

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: NOVEMBER 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	230	22.8	-	22.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	3,020	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	160	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	10,170	20.5	-	20.5	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	10,540	20.1	-	20.1	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	12,110	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	8,450	19.7	-	19.7	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	7,740	19.8	-	19.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	6,060	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	6,730	19.1	-	19.1	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	11,840	22.0	-	22.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	12,150	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL (3)	**585.5**	**89,200**	**21.2**	**-**	**21.2**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**25,330**	**11.5**	**91.8**	**43.3**	**13,218**	**GAS**	**325,700**	**1,028,001**	**334,820.0**	**1,220,896**	**4.82**	**3.75**
15. BIG BEND #2 TOTAL	**340**	**31,630**	**12.9**	**91.8**	**45.2**	**11,630**	**GAS**	**357,860**	**1,027,972**	**367,870.0**	**1,341,448**	**4.24**	**3.75**
16. B.B.#3 (GAS)	345	30,760	12.4	-	-	-	GAS	333,610	1,027,997	342,950.0	1,250,546	4.07	3.75
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**30,760**	**12.4**	**67.5**	**60.2**	**11,149**		**-**	**-**	**342,950.0**	**1,250,546**	**4.07**	**-**
19. B.B.#4 (GAS)	185	2,890	2.2	-	-	-	GAS	35,340	1,028,014	36,330.0	132,473	4.58	3.75
20. B.B.#4 (COAL)	437	54,970	17.5	-	-	-	COAL	30,680	22,500,652	690,320.0	2,342,690	4.26	76.36
21. BIG BEND #4 TOTAL	**437**	**57,860**	**18.4**	**83.3**	**41.5**	**12,559**		**-**	**-**	**726,650.0**	**2,475,163**	**4.28**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	52,600	-	54,080.0	197,173	-	3.75
23. B.B.C.T.#4 TOTAL	**56**	**790**	**2.0**	**98.2**	**67.2**	**12,899**	**GAS**	**9,910**	**1,028,254**	**10,190.0**	**37,148**	**4.70**	**3.75**
24. BIG BEND STATION TOTAL	**1,483**	**146,370**	**13.7**	**83.9**	**45.9**	**12,178**	**-**	**-**	**-**	**1,782,480.0**	**6,522,374**	**4.46**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	69,890	46.2	-	88.0	8,255	GAS	561,220	1,028,010	576,940.0	2,103,749	3.01	3.75
27. POLK #1 TOTAL	**220**	**69,890**	**44.1**	**93.4**	**88.0**	**8,255**	**-**	**-**	**-**	**576,940.0**	**2,103,749**	**3.01**	**-**
28. POLK #2 ST DUCT FIRING	120	16,260	18.8	-	64.8	8,274	GAS	130,870	1,027,967	134,530.0	490,570	3.02	3.75
29. POLK #2 ST W/O DUCT FIRING	341	477,397	-	-	-	-		3,270,672	1,028,008	3,362,278.6	12,260,208	2.57	3.75
30. POLK #2 ST TOTAL	**461**	**493,657**	**148.7**	**-**	**116.5**	**7,083**	**GAS**	**-**	**-**	**3,496,808.6**	**12,750,778**	**2.58**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	450	0.4	-	94.3	11,000	LGT OIL	844	5,864,929	4,950.0	107,590	23.91	127.48
33. POLK #2 TOTAL (4)	**150**	**450**	**0.4**	**-**	**94.3**	**11,000**	**-**	**-**	**-**	**4,950.0**	**107,590**	**23.91**	**-**
34. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	159	493	0.4	-	94.4	10,997	LGT OIL	925	5,860,973	5,421.4	117,915	23.92	127.48
36. POLK #3 TOTAL (4)	**150**	**493**	**0.5**	**-**	**94.4**	**10,997**	**-**	**-**	**-**	**5,421.4**	**117,915**	**23.92**	**-**
37. POLK #4 CT (GAS) TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**494,600**	**64.7**	**80.4**	**116.4**	**7,091**	**-**	**-**	**-**	**3,507,180.0**	**12,976,283**	**2.62**	**-**
40. POLK STATION TOTAL	**1,281**	**564,490**	**61.2**	**82.6**	**108.2**	**7,235**	**-**	**-**	**-**	**4,084,120.0**	**15,080,032**	**2.67**	**-**
41. BAYSIDE #1	701	403,520	79.9	97.2	82.1	7,319	GAS	2,872,790	1,028,001	2,953,230.0	10,768,736	2.67	3.75
42. BAYSIDE #2	929	222,600	33.3	58.1	64.8	7,492	GAS	1,622,340	1,027,990	1,667,750.0	6,081,387	2.73	3.75
43. BAYSIDE #3	56	1,460	3.6	98.6	81.5	12,274	GAS	17,430	1,028,112	17,920.0	65,337	4.48	3.75
44. BAYSIDE #4	56	1,290	3.2	98.6	82.3	12,147	GAS	15,250	1,027,541	15,670.0	57,165	4.43	3.75
45. BAYSIDE #5	56	2,360	5.9	98.6	84.3	11,979	GAS	27,500	1,028,000	28,270.0	103,085	4.37	3.75
46. BAYSIDE #6	56	2,060	5.1	98.6	83.6	12,039	GAS	24,120	1,028,192	24,800.0	90,415	4.39	3.75
47. BAYSIDE STATION TOTAL	**1,854**	**633,290**	**47.4**	**77.8**	**75.1**	**7,434**	**GAS**	**4,579,430**	**1,027,997**	**4,707,640.0**	**17,166,125**	**2.71**	**3.75**
48. SYSTEM TOTAL	**5,204**	**1,433,350**	**38.3**	**72.0**	**94.6**	**7,377**	**-**	**-**	**-**	**10,574,240.0**	**38,768,531**	**2.70**	**-**

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: DECEMBER 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	220	21.1	-	21.1	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	2,740	19.2	-	19.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	150	14.4	-	14.4	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	8,540	16.7	-	16.7	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	8,840	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	10,490	19.3	-	19.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	7,100	16.0	-	16.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	6,510	16.1	-	16.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	5,080	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	5,650	15.5	-	15.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	10,560	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	10,550	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**76,430**	**17.5**	**-**	**17.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**315**	**6,140**	**2.6**	**91.8**	**40.6**	**13,246**	**GAS**	**79,120**	**1,027,932**	**81,330.0**	**308,823**	**5.03**	**3.90**
15. BIG BEND #2 TOTAL	**350**	**22,310**	**8.6**	**91.8**	**41.9**	**11,656**	**GAS**	**252,950**	**1,028,029**	**260,040.0**	**987,320**	**4.43**	**3.90**
16. B.B.#3 (GAS)	355	17,290	6.5	-	-	-	GAS	184,170	1,028,018	189,330.0	718,857	4.16	3.90
17. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**355**	**17,290**	**6.5**	**92.1**	**61.7**	**10,950**		**-**	**-**	**189,330.0**	**718,857**	**4.16**	**-**
19. B.B.#4 (GAS)	195	3,940	2.7	-	-	-	GAS	49,440	1,028,115	50,830.0	192,975	4.90	3.90
20. B.B.#4 (COAL)	442	74,910	22.8	-	-	-	COAL	42,920	22,500,233	965,710.0	3,262,642	4.36	76.02
21. BIG BEND #4 TOTAL	**442**	**78,850**	**24.0**	**61.1**	**36.7**	**12,892**		**-**	**-**	**1,016,540.0**	**3,455,617**	**4.38**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	28,390	-	29,180.0	110,813	-	3.90
23. B.B.C.T.#4 TOTAL	**61**	**850**	**1.9**	**98.2**	**92.9**	**11,471**	**GAS**	**9,480**	**1,028,481**	**9,750.0**	**37,003**	**4.35**	**3.90**
24. BIG BEND STATION TOTAL	**1,523**	**125,440**	**11.1**	**83.2**	**40.3**	**12,412**	**-**	**-**	**-**	**1,556,990.0**	**5,618,433**	**4.48**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	230	40,240	23.5	-	86.6	8,308	GAS	325,220	1,027,981	334,320.0	1,269,407	3.15	3.90
27. POLK #1 TOTAL	**230**	**40,240**	**23.5**	**93.4**	**86.6**	**8,308**	**-**	**-**	**-**	**334,320.0**	**1,269,407**	**3.15**	**-**
28. POLK #2 ST DUCT FIRING	120	15,540	17.4	-	94.5	8,169	GAS	123,490	1,028,018	126,950.0	482,009	3.10	3.90
29. POLK #2 ST W/O DUCT FIRING	360	496,581	-	-	-	-		3,488,192	1,028,010	3,585,895.7	13,615,196	2.74	3.90
30. POLK #2 ST TOTAL	**480**	**512,121**	**143.4**	**-**	**122.9**	**7,250**	**GAS**	**-**	**-**	**3,712,845.7**	**14,097,205**	**2.75**	**-**
31. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
33. POLK #2 TOTAL [4]	**180**	**664**	**0.5**	**-**	**80.2**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,879**	**23.93**	**-**
34. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
36. POLK #3 TOTAL [4]	**180**	**664**	**0.5**	**-**	**80.2**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,878**	**23.93**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,200**	**513,449**	**57.5**	**97.2**	**122.5**	**7,260**	**-**	**-**	**-**	**3,727,459.9**	**14,414,962**	**2.81**	**-**
40. POLK STATION TOTAL	**1,430**	**553,689**	**52.0**	**96.6**	**115.8**	**7,336**	**-**	**-**	**-**	**4,061,779.9**	**15,684,369**	**2.83**	**-**
41. BAYSIDE #1	792	267,500	45.4	59.6	79.8	7,208	GAS	1,875,630	1,028,007	1,928,160.0	7,321,005	2.74	3.90
42. BAYSIDE #2	1,047	494,800	63.5	96.8	65.3	7,399	GAS	3,561,390	1,028,000	3,661,110.0	13,900,905	2.81	3.90
43. BAYSIDE #3	61	1,740	3.8	98.6	92.0	11,391	GAS	19,270	1,028,542	19,820.0	75,215	4.32	3.90
44. BAYSIDE #4	61	1,100	2.4	98.6	94.9	11,445	GAS	12,250	1,027,755	12,590.0	47,814	4.35	3.90
45. BAYSIDE #5	61	2,340	5.2	98.6	93.6	11,316	GAS	25,760	1,027,950	26,480.0	100,547	4.30	3.90
46. BAYSIDE #6	61	2,230	4.9	98.6	93.7	11,318	GAS	24,550	1,028,106	25,240.0	95,824	4.30	3.90
47. BAYSIDE STATION TOTAL	**2,083**	**769,710**	**49.7**	**82.9**	**69.9**	**7,371**	**GAS**	**5,518,850**	**1,028,004**	**5,673,400.0**	**21,541,310**	**2.80**	**3.90**
48. SYSTEM TOTAL	**5,622**	**1,525,269**	**36.5**	**77.8**	**87.6**	**7,403**	**-**	**-**	**-**	**11,292,169.9**	**42,844,112**	**2.81**	**-**

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 2020 THROUGH JUNE 2020

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
	HEAVY OIL						
1.	PURCHASES:						
2.	UNITS (BBL)	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0
5.	BURNED:						
6.	UNITS (BBL)	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0
9.	ENDING INVENTORY:						
10.	UNITS (BBL)	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0
	LIGHT OIL						
14.	PURCHASES:						
15.	UNITS (BBL)	0	0	0	0	0	0
16.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
17.	AMOUNT ($)	0	0	0	0	0	0
18.	BURNED:						
19.	UNITS (BBL)	2,492	2,332	2,492	1,890	2,331	2,412
20.	UNIT COST ($/BBL)	127.51	127.47	127.51	127.45	127.52	127.49
21.	AMOUNT ($)	317,757	297,257	317,757	240,881	297,257	307,507
22.	ENDING INVENTORY:						
23.	UNITS (BBL)	27,046	24,715	22,222	20,332	18,001	15,589
24.	UNIT COST ($/BBL)	127.48	127.48	127.48	127.49	127.48	127.48
25.	AMOUNT ($)	3,447,942	3,150,685	2,832,927	2,592,047	2,294,790	1,987,283
26.	DAYS SUPPLY: NORMAL	366,407	334,828	300,231	274,696	243,203	210,616
27.	DAYS SUPPLY: EMERGENCY	4	4	3	3	3	2
	COAL						
28.	PURCHASES:						
29.	UNITS (TONS)	0	0	0	0	0	0
30.	UNIT COST ($/TON)	0.00	0.00	0.00	0.00	0.00	0.00
31.	AMOUNT ($)	0	0	0	0	0	0
32.	BURNED:						
33.	UNITS (TONS)	62,380	3,830	0	10,610	1,840	28,040
34.	UNIT COST ($/TON)	76.89	71.68	0.00	77.72	77.26	76.16
35.	AMOUNT ($)	4,796,166	274,531	0	824,594	142,161	2,135,479
36.	ENDING INVENTORY:						
37.	UNITS (TONS)	367,992	364,162	364,162	353,552	351,712	323,672
38.	UNIT COST ($/TON)	70.17	70.19	70.19	70.26	70.27	70.48
39.	AMOUNT ($)	25,820,616	25,560,286	25,560,286	24,839,949	24,714,989	22,810,928
40.	DAYS SUPPLY:	506	2,270	2,691	795	326	177
	NATURAL GAS						
41.	PURCHASES:						
42.	UNITS (MCF)	9,335,262	8,907,432	9,459,532	11,144,069	12,315,877	13,351,492
43.	UNIT COST ($/MCF)	4.26	4.21	4.03	3.55	3.54	3.58
44.	AMOUNT ($)	39,790,461	37,540,967	38,164,838	39,544,044	43,617,012	47,828,357
45.	BURNED:						
46.	UNITS (MCF)	9,335,262	8,907,432	9,459,532	10,268,582	11,926,772	13,351,492
47.	UNIT COST ($/MCF)	4.26	4.22	4.04	3.63	3.58	3.58
48.	AMOUNT ($)	39,767,061	37,560,467	38,204,138	37,303,944	42,650,612	47,794,757
49.	ENDING INVENTORY:						
50.	UNITS (MCF)	291,829	291,829	291,829	1,167,315	1,556,420	1,556,420
51.	UNIT COST ($/MCF)	3.23	3.17	3.03	2.68	2.63	2.65
52.	AMOUNT ($)	943,500	924,000	884,700	3,124,800	4,091,200	4,124,800
53.	DAYS SUPPLY:	1	1	1	3	4	4
	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 ADJUSTMENTS (3) GAS-IGNITION

SCHEDULE E5

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

		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	0	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0	0
5.	BURNED:							
6.	UNITS (BBL)	0	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0	0
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	0	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	0	0	0	0	0	0	0
16.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17.	AMOUNT ($)	0	0	0	0	0	0	0
18.	BURNED:							
19.	UNITS (BBL)	2,492	2,492	2,412	1,407	1,769	2,492	27,013
20.	UNIT COST ($/BBL)	127.51	127.51	127.49	127.49	127.48	127.51	127.50
21.	AMOUNT ($)	317,757	317,757	307,507	179,379	225,505	317,757	3,444,078
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	13,096	10,604	8,191	6,784	5,015	2,523	2,523
24.	UNIT COST ($/BBL)	127.48	127.48	127.49	127.49	127.49	127.48	127.48
25.	AMOUNT ($)	1,669,526	1,351,768	1,044,261	864,882	639,377	321,620	321,620
26.	DAYS SUPPLY: NORMAL	176,934	143,266	110,665	91,655	67,755	34,087	-
27.	DAYS SUPPLY: EMERGENCY	2	2	1	1	1	0	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	0	40,000	70,000	27,500	42,500	27,500	207,500
30.	UNIT COST ($/TON)	0.00	63.66	59.98	61.36	59.14	61.36	60.88
31.	AMOUNT ($)	0	2,546,517	4,198,580	1,687,421	2,513,453	1,687,421	12,633,392
32.	BURNED:							
33.	UNITS (TONS)	69,440	71,090	72,510	17,520	30,680	42,920	410,860
34.	UNIT COST ($/TON)	76.35	76.28	76.23	77.47	76.36	76.02	76.40
35.	AMOUNT ($)	5,301,860	5,422,957	5,527,467	1,357,254	2,342,690	3,262,642	31,387,801
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	254,232	223,142	220,632	230,612	242,432	227,012	227,012
38.	UNIT COST ($/TON)	71.18	71.19	69.71	69.13	68.10	68.24	68.24
39.	AMOUNT ($)	18,096,463	15,885,874	15,380,446	15,942,031	16,510,124	15,492,146	15,492,146
40.	DAYS SUPPLY:	110	127	166	233	164	187	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	13,150,682	13,636,082	12,579,822	12,163,571	9,268,107	10,059,302	135,371,230
43.	UNIT COST ($/MCF)	3.64	3.62	3.65	3.69	3.80	3.92	3.76
44.	AMOUNT ($)	47,836,229	49,424,183	45,951,663	44,873,546	35,207,936	39,443,713	509,222,949
45.	BURNED:							
46.	UNITS (MCF)	13,150,682	13,636,082	12,579,822	12,163,571	9,657,212	10,059,302	134,495,743
47.	UNIT COST ($/MCF)	3.63	3.62	3.66	3.69	3.75	3.90	3.77
48.	AMOUNT ($)	47,794,629	49,424,183	45,980,463	44,839,946	36,200,336	39,263,713	506,784,249
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	1,556,420	1,556,420	1,556,420	1,556,420	1,167,315	1,167,315	1,167,315
51.	UNIT COST ($/MCF)	2.68	2.68	2.66	2.68	2.72	2.88	2.88
52.	AMOUNT ($)	4,166,400	4,166,400	4,137,600	4,171,200	3,178,800	3,358,800	3,358,800
53.	DAYS SUPPLY:	4	4	4	4	3	3	-
	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 ADJUSTMENTS (3) GAS-IGNITION

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

SCHEDULE E6

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) TOTAL COST $	(10) GAINS ON SALES
Jan-20	SEMINOLE	JURISD. SCH. - D	610.0	0.0	610.0	2.746	2.910	16,750.00	17,750.00	1,000.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**610.0**	**0.0**	**610.0**	**2.746**	**2.910**	**16,750.00**	**17,750.00**	**1,000.00**
Feb-20	SEMINOLE	JURISD. SCH. - D	560.0	0.0	560.0	2.755	2.920	15,430.00	16,352.00	922.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**560.0**	**0.0**	**560.0**	**2.755**	**2.920**	**15,430.00**	**16,352.00**	**922.00**
Mar-20	SEMINOLE	JURISD. SCH. - D	530.0	0.0	530.0	2.851	3.021	15,110.00	16,012.00	902.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**530.0**	**0.0**	**530.0**	**2.851**	**3.021**	**15,110.00**	**16,012.00**	**902.00**
Apr-20	SEMINOLE	JURISD. SCH. - D	600.0	0.0	600.0	2.797	2.964	16,780.00	17,782.00	1,002.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**600.0**	**0.0**	**600.0**	**2.797**	**2.964**	**16,780.00**	**17,782.00**	**1,002.00**
May-20	SEMINOLE	JURISD. SCH. - D	570.0	0.0	570.0	3.160	3.348	18,010.00	19,086.00	1,076.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**570.0**	**0.0**	**570.0**	**3.160**	**3.348**	**18,010.00**	**19,086.00**	**1,076.00**
Jun-20	SEMINOLE	JURISD. SCH. - D	580.0	0.0	580.0	3.059	3.241	17,740.00	18,800.00	1,060.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**580.0**	**0.0**	**580.0**	**3.059**	**3.241**	**17,740.00**	**18,800.00**	**1,060.00**

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2020 THROUGH DECEMBER 2020

SCHEDULE E6

(1)	(2)	(3)		(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH						
					WHEELED		CENTS/KWH				
		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-20	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	2.764	2.929	16,030.00	16,987.00	957.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**580.0**	**0.0**	**580.0**	**2.764**	**2.929**	**16,030.00**	**16,987.00**	**957.00**
Aug-20	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	2.721	2.883	15,780.00	16,722.00	942.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**580.0**	**0.0**	**580.0**	**2.721**	**2.883**	**15,780.00**	**16,722.00**	**942.00**
Sep-20	SEMINOLE	JURISD.	SCH. - D	570.0	0.0	570.0	3.151	3.339	17,960.00	19,033.00	1,073.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**570.0**	**0.0**	**570.0**	**3.151**	**3.339**	**17,960.00**	**19,033.00**	**1,073.00**
Oct-20	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	2.602	2.757	15,090.00	15,991.00	901.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**580.0**	**0.0**	**580.0**	**2.602**	**2.757**	**15,090.00**	**15,991.00**	**901.00**
Nov-20	SEMINOLE	JURISD.	SCH. - D	570.0	0.0	570.0	2.819	2.988	16,070.00	17,030.00	960.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**570.0**	**0.0**	**570.0**	**2.819**	**2.988**	**16,070.00**	**17,030.00**	**960.00**
Dec-20	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	2.740	2.903	15,890.00	16,839.00	949.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**580.0**	**0.0**	**580.0**	**2.740**	**2.903**	**15,890.00**	**16,839.00**	**949.00**
TOTAL											
Jan-20	SEMINOLE	JURISD.	SCH. - D	6,910.0	0.0	6,910.0	2.846	3.016	196,640.00	208,384.00	11,744.00
THRU	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
Dec-20	**TOTAL**			**6,910.0**	**0.0**	**6,910.0**	**2.846**	**3.016**	**196,640.00**	**208,384.00**	**11,744.00**

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

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-20	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
Feb-20	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-20	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-20	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-20	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-20	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-20	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-20	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-20	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-20	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-20	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-20	VARIOUS	FIRM	1,900.0	0.0	0.0	1,900.0	4.107	4.107	78,030.00
	TOTAL		1,900.0	0.0	0.0	1,900.0	4.107	4.107	78,030.00
TOTAL Jan-20 THRU Dec-20	VARIOUS	FIRM	1,900.0	0.0	0.0	1,900.0	4.107	4.107	78,030.00
	TOTAL		1,900.0	0.0	0.0	1,900.0	4.107	4.107	78,030.00

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

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		TOTAL $
		TYPE	TOTAL	FOR	FOR	MWH	(A)	(B)	FOR FUEL
	PURCHASED	&	MWH	OTHER	INTERRUP-	FOR	FUEL	TOTAL	ADJUST-
MONTH	FROM	SCHEDULE	PURCHASED	UTILITIES	TIBLE	FIRM	COST	COST	MENT
Jan-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,550.0	0.0	0.0	10,550.0	2.676	2.676	282,290.00
	TOTAL		10,550.0	0.0	0.0	10,550.0	2.676	2.676	282,290.00
Feb-20	VARIOUS	CO-GEN.							
		AS AVAIL.	9,970.0	0.0	0.0	9,970.0	2.750	2.750	274,130.00
	TOTAL		9,970.0	0.0	0.0	9,970.0	2.750	2.750	274,130.00
Mar-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,360.0	0.0	0.0	10,360.0	2.761	2.761	286,020.00
	TOTAL		10,360.0	0.0	0.0	10,360.0	2.761	2.761	286,020.00
Apr-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,280.0	0.0	0.0	10,280.0	2.850	2.850	293,010.00
	TOTAL		10,280.0	0.0	0.0	10,280.0	2.850	2.850	293,010.00
May-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,380.0	0.0	0.0	10,380.0	2.954	2.954	306,640.00
	TOTAL		10,380.0	0.0	0.0	10,380.0	2.954	2.954	306,640.00
Jun-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,250.0	0.0	0.0	10,250.0	2.931	2.931	300,450.00
	TOTAL		10,250.0	0.0	0.0	10,250.0	2.931	2.931	300,450.00
Jul-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,400.0	0.0	0.0	10,400.0	3.146	3.146	327,220.00
	TOTAL		10,400.0	0.0	0.0	10,400.0	3.146	3.146	327,220.00
Aug-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,420.0	0.0	0.0	10,420.0	3.193	3.193	332,740.00
	TOTAL		10,420.0	0.0	0.0	10,420.0	3.193	3.193	332,740.00
Sep-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,220.0	0.0	0.0	10,220.0	2.842	2.842	290,490.00
	TOTAL		10,220.0	0.0	0.0	10,220.0	2.842	2.842	290,490.00
Oct-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,450.0	0.0	0.0	10,450.0	3.266	3.266	341,270.00
	TOTAL		10,450.0	0.0	0.0	10,450.0	3.266	3.266	341,270.00
Nov-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,270.0	0.0	0.0	10,270.0	3.438	3.438	353,060.00
	TOTAL		10,270.0	0.0	0.0	10,270.0	3.438	3.438	353,060.00
Dec-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,380.0	0.0	0.0	10,380.0	2.827	2.827	293,490.00
	TOTAL		10,380.0	0.0	0.0	10,380.0	2.827	2.827	293,490.00
TOTAL	VARIOUS	CO-GEN.							
Jan-20		AS AVAIL.	123,930.0	0.0	0.0	123,930.0	2.970	2.970	3,680,810.00
THRU	TOTAL		123,930.0	0.0	0.0	123,930.0	2.970	2.970	3,680,810.00
Dec-20									

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

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-20	VARIOUS	ECONOMY	340.0	0.0	340.0	5.141	17,480.00	79.679	270,910.00	253,430.00
Feb-20	VARIOUS	ECONOMY	1,100.0	0.0	1,100.0	4.183	46,010.00	48.922	538,140.00	492,130.00
Mar-20	VARIOUS	ECONOMY	5,830.0	0.0	5,830.0	3.952	230,400.00	14.414	840,360.00	609,960.00
Apr-20	VARIOUS	ECONOMY	3,300.0	0.0	3,300.0	3.788	124,990.00	49.790	1,643,070.00	1,518,080.00
May-20	VARIOUS	ECONOMY	12,600.0	0.0	12,600.0	4.240	534,220.00	21.411	2,697,770.00	2,163,550.00
Jun-20	VARIOUS	ECONOMY	10,590.0	0.0	10,590.0	4.930	522,050.00	15.393	1,630,150.00	1,108,100.00
Jul-20	VARIOUS	ECONOMY	2,710.0	0.0	2,710.0	6.595	178,720.00	60.756	1,646,490.00	1,467,770.00
Aug-20	VARIOUS	ECONOMY	7,150.0	0.0	7,150.0	6.154	440,030.00	28.235	2,018,830.00	1,578,800.00
Sep-20	VARIOUS	ECONOMY	7,430.0	0.0	7,430.0	4.702	349,380.00	29.948	2,225,100.00	1,875,720.00
Oct-20	VARIOUS	ECONOMY	24,680.0	0.0	24,680.0	4.740	1,169,790.00	13.007	3,210,200.00	2,040,410.00
Nov-20	VARIOUS	ECONOMY	6,450.0	0.0	6,450.0	3.786	244,200.00	15.353	990,270.00	746,070.00
Dec-20	VARIOUS	ECONOMY	3,940.0	0.0	3,940.0	5.108	201,250.00	26.414	1,040,720.00	839,470.00
TOTAL	VARIOUS	ECONOMY	**86,120.0**	**0.0**	**86,120.0**	**4.713**	**4,058,520.00**	**21.774**	**18,752,010.00**	**14,693,490.00**

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

	Current	Projected	Projected	Difference[1]	
	Apr 2019 - Dec 2019	Jan 2020	Feb 2020 - Dec 2020	$	%
Base Rate Revenue	66.53	68.08	68.08	1.55	2.3%
Fuel Recovery Revenue	29.13	27.02	27.02	(2.11)	-7.2%
Conservation Revenue	3.21	2.32	2.32	(0.89)	-27.7%
Capacity Revenue	-0.10	0.10	0.10	0.20	-200.0%
Environmental Revenue	2.22	2.44	2.44	0.22	9.9%
Final Tax Savings Credit	0.00	-9.06	0.00		
Florida Gross Receipts Tax Revenue	2.59	2.33	2.56	(0.03)	-1.2%
TOTAL REVENUE	**$103.58**	**$93.23**	**$102.52**	**($1.06)**	**-1.0%**

[1]Difference does not include effect of Final Tax Savings Credit included in January 2020 bills. If included, the total difference is ($10.35) or -10.0%

SCHEDULE H1

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

	ACTUAL 2017	ACTUAL 2018	ACT/EST 2019	EST 2020	DIFFERENCE (%) 2018-2017	2019-2018	2020-2019
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL (1)	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL (1)	10,825	51,583	1,843,356	3,444,078	376.5%	3473.6%	86.8%
3 COAL	198,469,769	125,828,296	46,074,730	31,387,801	-36.6%	-63.4%	-31.9%
4 NATURAL GAS	412,107,824	505,830,903	508,630,766	506,784,249	22.7%	0.6%	-0.4%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**610,588,418**	**631,710,782**	**556,548,852**	**541,616,128**	**3.5%**	**-11.9%**	**-2.7%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL (1)	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL (1)	36	173	7,651	14,397	380.6%	4322.5%	88.2%
10 COAL	6,013,495	3,533,451	1,172,863	747,700	-41.2%	-66.8%	-36.3%
11 NATURAL GAS	13,685,288	16,096,514	17,520,700	18,120,647	17.6%	8.8%	3.4%
12 NUCLEAR	0	118,322	775,222	1,413,420	0.0%	555.2%	82.3%
13 OTHER	44,594	0	0	0	-100.0%	0.0%	0.0%
14 TOTAL (MWH)	**19,743,413**	**19,748,460**	**19,476,436**	**20,296,164**	**0.0%**	**-1.4%**	**4.2%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) (1)	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) (1)	85	405	14,458	27,013	376.5%	3469.9%	86.8%
17 COAL (TON)	2,655,830	1,626,026	596,461	410,860	-38.8%	-63.3%	-31.1%
18 NATURAL GAS (MCF)	100,512,457	121,581,188	132,814,975	134,495,743	21.0%	9.2%	1.3%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL (1)	0	0	0	0	0.0%	0.0%	0.0%
22 LIGHT OIL (1)	495	1,349	84,772	158,399	172.5%	6184.0%	86.9%
23 COAL	64,801,532	38,881,879	13,661,025	9,244,440	-40.0%	-64.9%	-32.3%
24 NATURAL GAS	102,771,003	124,229,756	135,901,765	137,754,760	20.9%	9.4%	1.4%
25 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26 OTHER	0	0	0	0	0.0%	0.0%	0.0%
27 TOTAL (MMBTU)	**167,573,029**	**163,112,984**	**149,647,562**	**147,157,599**	**-2.7%**	**-8.3%**	**-1.7%**
GENERATION MIX (% MWH)							
28 HEAVY OIL (1)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
29 LIGHT OIL (1)	0.00	0.00	0.04	0.07	0.0%	0.0%	75.0%
30 COAL	30.45	17.89	6.02	3.69	-41.2%	-66.3%	-38.7%
31 NATURAL GAS	69.32	81.51	89.96	89.28	17.6%	10.4%	-0.8%
32 NUCLEAR	0.00	0.60	3.98	6.96	0.0%	563.3%	74.9%
33 OTHER	0.23	0.00	0.00	0.00	-100.0%	0.0%	0.0%
34 TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**0.0%**	**0.0%**	**0.0%**
FUEL COST PER UNIT							
35 HEAVY OIL ($/BBL) (1)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
36 LIGHT OIL ($/BBL) (1)	127.35	127.37	127.50	127.50	0.0%	0.1%	0.0%
37 COAL ($/TON)	74.73	77.38	77.25	76.40	3.5%	-0.2%	-1.1%
38 NATURAL GAS ($/MCF)	4.10	4.16	3.83	3.77	1.5%	-7.9%	-1.6%
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)							
41 HEAVY OIL (1)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
42 LIGHT OIL (1)	21.87	38.24	21.74	21.74	74.9%	-43.1%	0.0%
43 COAL	3.06	3.24	3.37	3.40	5.9%	4.0%	0.9%
44 NATURAL GAS	4.01	4.07	3.74	3.68	1.5%	-8.1%	-1.6%
45 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL ($/MMBTU)	**3.64**	**3.87**	**3.72**	**3.68**	**6.3%**	**-3.9%**	**-1.1%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL (1)	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL (1)	13,750	7,798	11,080	11,002	-43.3%	42.1%	-0.7%
50 COAL	10,776	11,004	11,648	12,364	2.1%	5.9%	6.1%
51 NATURAL GAS	7,510	7,718	7,757	7,602	2.8%	0.5%	-2.0%
52 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53 OTHER	0	0	0	0	0.0%	0.0%	0.0%
54 TOTAL (BTU/KWH)	**8,488**	**8,260**	**7,684**	**7,251**	**-2.7%**	**-7.0%**	**-5.6%**
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL (1)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
56 LIGHT OIL (1)	30.07	29.82	24.09	23.92	-0.8%	-19.2%	-0.7%
57 COAL	3.30	3.56	3.93	4.20	7.9%	10.4%	6.9%
58 NATURAL GAS	3.01	3.14	2.90	2.80	4.3%	-7.6%	-3.4%
59 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61 TOTAL (cents/KWH)	**3.09**	**3.20**	**2.86**	**2.67**	**3.6%**	**-10.6%**	**-6.6%**

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

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

LEVELIZED AND TIERED FUEL RATE

JANUARY 2020 - DECEMBER 2020

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2020 through December 2020

	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	6,502,646	3.016	196,119,803	2.702	175,698,454
TIER II (Over 1,000) kWh	2,977,076	3.016	89,788,612	3.702	110,209,961
Total	9,479,722		285,908,415		285,908,415

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 4

CAPITAL PROJECTS APPROVED FOR

FUEL CLAUSE RECOVERY

JANUARY 2020 - DECEMBER 2020

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

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1 BEGINNING BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348
2 ADD INVESTMENT: Big Bend Unit 3 (Jan 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2a ADD INVESTMENT: Big Bend Unit 4 (May 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2b ADD INVESTMENT: Big Bend Unit 2 (June 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2c ADD INVESTMENT: Big Bend Unit 1 (November 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
3 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4 ENDING BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348
5													
6													
7 AVERAGE BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	
8 DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	
9 DEPRECIATION EXPENSE	$348,506	$348,506	$348,506	$348,506	$238,475	-	-	-	-	-	-	-	$1,632,498
10 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11 BEGINNING BALANCE DEPRECIATION	$19,277,850	$19,626,355	$19,974,861	$20,323,367	$20,671,873	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$19,277,850
12 ENDING BALANCE DEPRECIATION	$19,626,355	$19,974,861	$20,323,367	$20,671,873	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348
13													
14													
15 ENDING NET INVESTMENT	$1,283,993	$935,487	$586,981	$238,475	$0	$0	$0	$0	$0	$0	$0	$0	$0
16													
17													
18 AVERAGE INVESTMENT	$1,458,246	$1,109,740	$761,234	$412,728	$119,238	$0	$0	$0	$0	$0	$0	$0	
19 ALLOWED EQUITY RETURN	.37413%	.37413%	.37413%	.37413%	.37413%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%	
20 EQUITY COMPONENT AFTER-TAX	$5,456	$4,152	$2,848	$1,544	$446	$0	$0	$0	$0	$0	$0	$0	$14,446
21 CONVERSION TO PRE-TAX	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	
22 EQUITY COMPONENT PRE-TAX	$7,327	$5,576	$3,825	$2,074	$599	$0	$0	$0	$0	$0	$0	$0	$19,401
23													
24 ALLOWED DEBT RETURN	.14474%	.14474%	.14474%	.14474%	.14474%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%
25 DEBT COMPONENT	$2,111	$1,606	$1,102	$597	$173	$0	$0	$0	$0	$0	$0	$0	$5,589
26 TAX REFORM TRUEUP													
27 TOTAL RETURN REQUIREMENTS	$9,438	$7,182	$4,927	$2,671	$772	$0	$0	$0	$0	$0	$0	$0	$24,990
28 PRIOR MONTH TRUE-UP													
29 TOTAL DEPRECIATION & RETURN	$357,944	$355,688	$353,433	$351,177	$239,247	$0	$0	$0	$0	$0	$0	$0	$1,657,489
30													
31 ESTIMATED FUEL SAVINGS	$309,972	$174,435	$573,395	$468,884	$587,882	$0	$0	$0	$0	$0	$0	$0	$2,114,569
32 TOTAL DEPRECIATION & RETURN	$357,944	$355,688	$353,433	$351,177	$239,247	$0	$0	$0	$0	$0	$0	$0	$1,657,489
33 NET BENEFIT (COST) TO RATEPAYER	($47,972)	($181,253)	$219,963	$117,707	$348,635	$0	$0	$0	$0	$0	$0	$0	$457,080

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - DECEMBER USING AN ANNUAL RATE OF 7.7662% (EQUITY 6.0293% , DEBT 1.7369%). RATES ARE BASED ON THE MAY 2019 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 25.345%
37 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

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

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

ITC split between Debt and Equity:

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

Deferred ITC - Weighted Cost:

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

Total Equity Cost Rate:

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

Total Debt Cost Rate:

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

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

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20190001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2020 THROUGH DECEMBER 2020

TESTIMONY AND EXHIBIT

OF

JEREMY B. CAIN

FILED: SEPTEMBER 3, 2019

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEREMY B. CAIN

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

A. My name is Jeremy B. Cain. 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, Asset Management.

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

A. I hold a Bachelor of Science degree in Mechanical Engineering in 2003 from the University of New Brunswick, Canada, and I am a registered Professional Engineer in Canada. I have accumulated 10 years of experience in the electric utility industry, with experience in the areas of unit maintenance manager, project manager for a unit upgrade, operations manager for that plant, as well as various other engineering positions, including responsibility for physical asset management. In my current role I am responsible for development of Tampa

Electric’s Asset Management programs and processes, specifically for the Bayside Power Station, and coordinating these programs with the Asset Management processes throughout Energy Supply. Asset Management programs include work management processes, reliability programs, and information technology, operational and capital investment analysis, recommendations, and planning to maintain and improve the performance of the generating units.

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. JC-1, 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 2020 period.

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

A. Four natural gas combined cycle units and one coal unit are included. These are Polk Units 1 and 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 2020 through December 2020 represent 87 percent of the total forecasted system net generation for this period.

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, Polk Unit 2 and Bayside Unit 1 outages were identified as outliers and 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 2020 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 2020 period, the projected EUOF for Bayside Unit 1 is 1.7 percent, the POF is 6.6 percent. Therefore, the target EAF for Bayside Unit 1 equals 91.7 percent or:

$$100\% - (1.7\% + 6.6\%) = 91.7\%$$

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 Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80\ (1.7\%) + 0.95\ (6.6\%)] = 92.4\%$$

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 Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (1.7\%) + 1.10\ (6.6\%)] = 90.3\%$$

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 through December 2020 are shown on page 17 of Document No. 1. One GPIF unit has a major planned outage 28 days or greater in 2020; therefore, one Critical Path Method diagram is provided.

Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for planned outages from February 29, 2020 to March 11, 2020 and December 2, 2020 to December 13, 2020. There are 576 planned outage hours scheduled for the 2020 period, with a total of 8,784 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 6.6 percent or:

$$\frac{576}{8{,}784} \times 100\% = 6.6\%$$

The factor for each unit is shown on pages 5 and 12 through 16 of Document No. 1. Polk Unit 1 has a POF of 8.5 percent. Polk Unit 2 has a POF of 12.6 percent. Bayside Unit 2 has a POF of 6.6 percent, and Big Bend Unit 4 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 1.7 percent for Bayside Unit 1. The EUOF of Bayside Unit 1 is verified by the data shown on page 15, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(42 + 111)}{8,784} \times 100\% = 1.7\%$$

Relative to Bayside Unit 1, the EUOF of 1.7 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Polk Unit 1

The projected EUOF for this unit is 16 percent. The unit will have two planned outages in 2020, and the POF is 8.5 percent. Therefore, the target equivalent availability for this unit is 75.5 percent.

Polk Unit 2

The projected EUOF for this unit is 2.5 percent. The unit will have two planned outages in 2020, and the POF is 12.6 percent. Therefore, the target equivalent availability for this unit is 84.9 percent.

Bayside Unit 1

The projected EUOF for this unit is 1.7 percent. The unit will have two planned outages in 2020, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 91.7 percent.

Bayside Unit 2

The projected EUOF for this unit is 4.5 percent. The unit will have two planned outages in 2020, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 88.9 percent.

Big Bend Unit 4

The projected EUOF for this unit is 22.8 percent. The unit will have two planned outages in 2020, and the POF is 21.8 percent. Therefore, the target equivalent availability for this unit is 55.4 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 84.9 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 Bayside Unit 1 on page 15 of Document No. 1. Except for the months of February, March, and December, 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 February, March, and December, 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 aforementioned agreed upon GPIF methodology and co-firing.

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 24 through 28 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 2020 period.

A. The heat rate target for Polk Unit 1 is 10,018 Btu/Net kWh with a range of ±1,411 Btu/Net kWh. The heat rate target for Polk Unit 2 is 7,209 Btu/Net kWh with a range of ±394 Btu/Net kWh. The heat rate for Bayside Unit 1 is

7,379 Btu/Net kWh with a range of ±119 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,499 Btu/Net kWh with a range of ±250 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,837 Btu/Net kWh with a range of ±427 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within a range for each target. This is shown on page 4, and pages 7 through 11 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 11. 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 $435,826,930 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 $21,602,740, 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 Bayside Unit 1, the weighting factor for average net operating heat rate is 7.6 percent as shown in the right-hand column on Document No. 1, page 6. Pages 7 through 11 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 10 of Document No. 1, if Bayside Unit 1, operates at 7,260 average net operating heat rate, fuel savings would equal $1,649,500, 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 11. 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 $21,602,740. 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 through December 2020 is $3,209,099,543. This produces the maximum allowed jurisdictional incentive of $10,774,122 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 $10,774,122.

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).

$$\begin{aligned} GPIP = (&0.0315\ EAP_{PK1} + 0.6840\ EAP_{PK2} \\ &+ 0.05630\ EAP_{BAY1} + 0.0839\ EAP_{BAY2} \\ &+ 0.0140\ EAP_{BB4} + 0.3596\ HRP_{PK2} \\ &+ 0.0764\ HRP_{BAY1} + 0.1543\ HRP_{BAY2} \\ &+ 0.0443\ HRP_{BB4} + 0.1115\ HRP_{PK1}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2020 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

JEREMY B. CAIN

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2020 - DECEMBER 2020

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2020 - DECEMBER 2020
TARGETS
TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2020 - DECEMBER 2020

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	21,602.7	10,774.1
+9	19,442.5	9,696.7
+8	17,282.2	8,619.3
+7	15,121.9	7,541.9
+6	12,961.6	6,464.5
+5	10,801.4	5,387.1
+4	8,641.1	4,309.6
+3	6,480.8	3,232.2
+2	4,320.5	2,154.8
+1	2,160.3	1,077.4
0	0.0	0.0
-1	(1,976.7)	(1,077.4)
-2	(3,953.4)	(2,154.8)
-3	(5,930.1)	(3,232.2)
-4	(7,906.8)	(4,309.6)
-5	(9,883.5)	(5,387.1)
-6	(11,860.2)	(6,464.5)
-7	(13,836.9)	(7,541.9)
-8	(15,813.6)	(8,619.3)
-9	(17,790.3)	(9,696.7)
-10	(19,767.0)	(10,774.1)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2020 - DECEMBER 2020

Line 1	Beginning of period balance of common equity: End of month common equity:		$	3,168,529,000	
Line 2	Month of January	2020	$	3,093,371,000	
Line 3	Month of February	2020	$	3,119,793,544	
Line 4	Month of March	2020	$	3,146,441,780	
Line 5	Month of April	2020	$	3,195,404,857	
Line 6	Month of May	2020	$	3,222,698,940	
Line 7	Month of June	2020	$	3,250,226,160	
Line 8	Month of July	2020	$	3,174,204,129	
Line 9	Month of August	2020	$	3,201,317,123	
Line 10	Month of September	2020	$	3,228,661,706	
Line 11	Month of October	2020	$	3,277,804,312	
Line 12	Month of November	2020	$	3,305,802,224	
Line 13	Month of December	2020	$	3,334,039,285	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	3,209,099,543	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			74.46%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	10,774,122	
Line 18	Jurisdictional Sales			19,521,559	MWH
Line 19	Total Sales			19,521,559	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			100.00%	
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)		$	10,774,122	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)		$	10,801,371	
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)		$	10,774,122	

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 2020 - DECEMBER 2020

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 4	1.40%	55.4	61.0	44.1	301.8	(1,622.9)
POLK 1	3.15%	75.5	79.1	68.3	680.0	(107.9)
POLK 2	6.84%	84.9	86.1	82.7	1,477.8	(823.7)
BAYSIDE 1	5.63%	91.7	92.4	90.3	1,216.3	(475.9)
BAYSIDE 2	8.39%	88.9	90.1	86.4	1,811.8	(621.7)
GPIF SYSTEM	**25.40%**					

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	4.43%	10,837	52.3	10,410	11,264	956.4	(956.4)
POLK 1	11.15%	10,018	84.8	8,607	11,429	2,408.6	(2,408.6)
POLK 2	35.96%	7,209	72.9	6,816	7,603	7,768.2	(7,768.2)
BAYSIDE 1	7.64%	7,379	84.2	7,260	7,498	1,649.5	(1,649.5)
BAYSIDE 2	15.43%	7,499	70.9	7,250	7,749	3,332.3	(3,332.3)
GPIF SYSTEM	**74.60%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 20 - DEC 20 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 18 - DEC 18 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 17 - DEC 17 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 16 - DEC 16 POF	EUOF	EUOR
BIG BEND 4	1.40%	5.5%	21.8	22.8	29.1	19.1	20.6	26.6	0.0	30.7	31.2	6.7	18.8	21.9
POLK 1	3.15%	12.4%	8.5	16.0	17.5	28.1	10.7	16.3	4.4	9.6	10.4	13.3	4.2	16.4
POLK 2	6.84%	26.9%	12.6	2.5	2.9	2.0	3.3	3.2	1.8	6.9	7.8	0.0	4.5	48.5
BAYSIDE 1	5.63%	22.2%	6.6	1.7	1.9	5.3	1.6	1.7	11.6	2.0	2.4	20.0	1.3	1.8
BAYSIDE 2	8.39%	33.0%	6.6	4.5	4.9	19.6	2.5	3.1	9.4	5.1	5.7	7.1	2.9	5.0
GPIF SYSTEM	**25.40%**	**100.0%**	**9.3**	**5.8**	**6.6**	**12.7**	**4.5**	**5.8**	**6.7**	**6.9**	**7.5**	**8.8**	**4.0**	**18.3**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**84.9**			**82.8**			**86.4**			**87.2**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
9.4	**5.1**	**10.5**	**85.5**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 20 - DEC 20	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 18 - DEC 18	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 17 - DEC 17	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 16 - DEC 16
BIG BEND 4	4.43%	5.9%	10,837	10,921	10,852	10,619
POLK 1	11.15%	14.9%	10,018	10,304	10,140	9,959
POLK 2	35.96%	48.2%	7,209	7,134	7,190	8,306
BAYSIDE 1	7.64%	10.2%	7,379	7,366	7,317	7,442
BAYSIDE 2	15.43%	20.7%	7,499	7,400	7,444	7,574
GPIF SYSTEM	**74.60%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**7,922**	**7,911**	**7,914**	**8,450**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2020 - DECEMBER 2020
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	435,826.93	435,525.16	301.77	1.40%
EA_1 POLK 1	435,826.93	435,146.88	680.05	3.15%
EA_2 POLK 2	435,826.93	434,349.08	1,477.85	6.84%
EA_3 BAYSIDE 1	435,826.93	434,610.61	1,216.32	5.63%
EA_4 BAYSIDE 2	435,826.93	434,015.13	1,811.80	8.39%
AVERAGE HEAT RATE				
AHR_3 BIG BEND 4	435,826.93	434,870.57	956.36	4.43%
AHR_1 POLK 1	435,826.93	433,418.34	2,408.59	11.15%
AHR_2 POLK 2	435,826.93	428,058.70	7,768.23	35.96%
AHR_3 BAYSIDE 1	435,826.93	434,177.45	1,649.48	7.64%
AHR_4 BAYSIDE 2	435,826.93	432,494.64	3,332.29	15.43%
TOTAL SAVINGS			**21,602.74**	**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.

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2020 - DECEMBER 2020

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	301.8	61.0	+10	956.4	10,410
+9	271.6	60.5	+9	860.7	10,445
+8	241.4	59.9	+8	765.1	10,480
+7	211.2	59.3	+7	669.5	10,516
+6	181.1	58.8	+6	573.8	10,551
+5	150.9	58.2	+5	478.2	10,586
+4	120.7	57.7	+4	382.5	10,621
+3	90.5	57.1	+3	286.9	10,656
+2	60.4	56.5	+2	191.3	10,691
+1	30.2	56.0	+1	95.6	10,727
					10,762
0	0.0	55.4	0	0.0	10,837
					10,912
-1	(162.3)	54.3	-1	(95.6)	10,947
-2	(324.6)	53.1	-2	(191.3)	10,982
-3	(486.9)	52.0	-3	(286.9)	11,017
-4	(649.2)	50.9	-4	(382.5)	11,053
-5	(811.5)	49.8	-5	(478.2)	11,088
-6	(973.7)	48.6	-6	(573.8)	11,123
-7	(1,136.0)	47.5	-7	(669.5)	11,158
-8	(1,298.3)	46.4	-8	(765.1)	11,193
-9	(1,460.6)	45.2	-9	(860.7)	11,228
-10	(1,622.9)	44.1	-10	(956.4)	11,264

Weighting Factor = 1.40% Weighting Factor = 4.43%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2020 - DECEMBER 2020

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	680.0	79.1	+10	2,408.6	8,607
+9	612.0	78.8	+9	2,167.7	8,741
+8	544.0	78.4	+8	1,926.9	8,874
+7	476.0	78.1	+7	1,686.0	9,008
+6	408.0	77.7	+6	1,445.2	9,141
+5	340.0	77.3	+5	1,204.3	9,275
+4	272.0	77.0	+4	963.4	9,409
+3	204.0	76.6	+3	722.6	9,542
+2	136.0	76.2	+2	481.7	9,676
+1	68.0	75.9	+1	240.9	9,809
					9,943
0	0.0	75.5	0	0.0	10,018
					10,093
-1	(10.8)	74.8	-1	(240.9)	10,226
-2	(21.6)	74.1	-2	(481.7)	10,360
-3	(32.4)	73.3	-3	(722.6)	10,494
-4	(43.1)	72.6	-4	(963.4)	10,627
-5	(53.9)	71.9	-5	(1,204.3)	10,761
-6	(64.7)	71.2	-6	(1,445.2)	10,894
-7	(75.5)	70.4	-7	(1,686.0)	11,028
-8	(86.3)	69.7	-8	(1,926.9)	11,162
-9	(97.1)	69.0	-9	(2,167.7)	11,295
-10	(107.9)	68.3	-10	(2,408.6)	11,429
	Weighting Factor =	3.15%		Weighting Factor =	11.15%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2020 - DECEMBER 2020

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	1,477.8	86.1	+10	7,768.2	6,816
+9	1,330.1	85.9	+9	6,991.4	6,847
+8	1,182.3	85.8	+8	6,214.6	6,879
+7	1,034.5	85.7	+7	5,437.8	6,911
+6	886.7	85.6	+6	4,660.9	6,943
+5	738.9	85.5	+5	3,884.1	6,975
+4	591.1	85.4	+4	3,107.3	7,007
+3	443.4	85.3	+3	2,330.5	7,039
+2	295.6	85.1	+2	1,553.6	7,071
+1	147.8	85.0	+1	776.8	7,102
					7,134
0	0.0	84.9	0	0.0	7,209
					7,284
-1	(82.4)	84.7	-1	(776.8)	7,316
-2	(164.7)	84.5	-2	(1,553.6)	7,348
-3	(247.1)	84.2	-3	(2,330.5)	7,380
-4	(329.5)	84.0	-4	(3,107.3)	7,412
-5	(411.9)	83.8	-5	(3,884.1)	7,444
-6	(494.2)	83.6	-6	(4,660.9)	7,475
-7	(576.6)	83.3	-7	(5,437.8)	7,507
-8	(659.0)	83.1	-8	(6,214.6)	7,539
-9	(741.4)	82.9	-9	(6,991.4)	7,571
-10	(823.7)	82.7	-10	(7,768.2)	7,603
	Weighting Factor =	6.84%		Weighting Factor =	35.96%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2020 - DECEMBER 2020

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	1,216.3	92.4	+10	1,649.5	7,260
+9	1,094.7	92.3	+9	1,484.5	7,265
+8	973.1	92.2	+8	1,319.6	7,269
+7	851.4	92.2	+7	1,154.6	7,273
+6	729.8	92.1	+6	989.7	7,278
+5	608.2	92.0	+5	824.7	7,282
+4	486.5	92.0	+4	659.8	7,286
+3	364.9	91.9	+3	494.8	7,291
+2	243.3	91.8	+2	329.9	7,295
+1	121.6	91.8	+1	164.9	7,300
					7,304
0	0.0	91.7	0	0.0	7,379
					7,454
-1	(47.6)	91.6	-1	(164.9)	7,458
-2	(95.2)	91.4	-2	(329.9)	7,463
-3	(142.8)	91.3	-3	(494.8)	7,467
-4	(190.3)	91.2	-4	(659.8)	7,471
-5	(237.9)	91.0	-5	(824.7)	7,476
-6	(285.5)	90.9	-6	(989.7)	7,480
-7	(333.1)	90.7	-7	(1,154.6)	7,484
-8	(380.7)	90.6	-8	(1,319.6)	7,489
-9	(428.3)	90.5	-9	(1,484.5)	7,493
-10	(475.9)	90.3	-10	(1,649.5)	7,498
	Weighting Factor =	5.63%		Weighting Factor =	7.64%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2020 - DECEMBER 2020

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,811.8	90.1	+10	3,332.3	7,250
+9	1,630.6	90.0	+9	2,999.1	7,267
+8	1,449.4	89.9	+8	2,665.8	7,285
+7	1,268.3	89.8	+7	2,332.6	7,302
+6	1,087.1	89.6	+6	1,999.4	7,319
+5	905.9	89.5	+5	1,666.1	7,337
+4	724.7	89.4	+4	1,332.9	7,354
+3	543.5	89.3	+3	999.7	7,372
+2	362.4	89.1	+2	666.5	7,389
+1	181.2	89.0	+1	333.2	7,407
					7,424
0	0.0	88.9	0	0.0	7,499
					7,574
-1	(62.2)	88.7	-1	(333.2)	7,592
-2	(124.3)	88.4	-2	(666.5)	7,609
-3	(186.5)	88.2	-3	(999.7)	7,627
-4	(248.7)	87.9	-4	(1,332.9)	7,644
-5	(310.9)	87.7	-5	(1,666.1)	7,661
-6	(373.0)	87.4	-6	(1,999.4)	7,679
-7	(435.2)	87.2	-7	(2,332.6)	7,696
-8	(497.4)	86.9	-8	(2,665.8)	7,714
-9	(559.5)	86.7	-9	(2,999.1)	7,731
-10	(621.7)	86.4	-10	(3,332.3)	7,749
	Weighting Factor =	8.39%		Weighting Factor =	15.43%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2020 - DECEMBER 2020

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-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020
1. EAF (%)	70.9	4.9	0.0	42.5	70.9	70.9	70.9	70.9	70.9	70.9	68.5	50.3	55.4
2. POF	0.0	93.1	100.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	29.0	21.8
3. EUOF	29.1	2.0	0.0	17.5	29.1	29.1	29.1	29.1	29.1	29.1	28.2	20.7	22.8
4. EUOR	29.1	29.1	0.0	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	624	41	0	120	177	303	588	624	603	162	199	443	3,884
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	120	655	743	600	567	417	156	120	117	582	522	301	4,900
9. POH	0	648	743	288	0	0	0	0	0	0	24	216	1,919
10. EFOH	148	10	0	86	148	143	148	148	143	148	138	105	1,363
11. EMOH	69	4	0	40	69	67	69	69	67	69	65	49	637
12. OPER BTU (GBTU)	1,128	69	0	225	319	640	1,171	1,273	1,288	329	425	806	7,676
13. NET GEN (MWH)	103,820	6,380	0	20,750	29,350	59,180	108,140	117,580	119,150	30,400	39,290	74,240	708,280
14. ANOHR (Btu/kwh)	10,863	10,879	11,112	10,850	10,861	10,816	10,833	10,826	10,812	10,827	10,813	10,862	10,837
15. NOF (%)	47.3	44.2	0.0	49.8	47.8	56.3	53.0	54.3	56.9	54.1	56.9	47.6	52.3
16. NPC (MW)	352	352	352	347	347	347	347	347	347	347	347	352	349

17. ANOHR EQUATION ANOHR = NOF(-5.260) + 11,112

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2020 - DECEMBER 2020

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020
1. EAF (%)	77.2	59.7	82.5	82.5	82.5	82.5	82.5	82.5	35.8	71.9	82.5	82.5	75.5
2. POF	6.5	27.6	0.0	0.0	0.0	0.0	0.0	0.0	56.7	12.9	0.0	0.0	8.5
3. EUOF	16.4	12.7	17.5	17.5	17.5	17.5	17.5	17.5	7.6	15.2	17.5	17.5	16.0
4. EUOR	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	74	75	128	293	294	367	360	402	148	350	387	179	3,057
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	670	621	615	427	450	353	384	342	572	394	334	565	5,727
9. POH	48	192	0	0	0	0	0	0	408	96	0	0	744
10. EFOH	64	47	69	67	69	67	69	69	29	60	67	69	745
11. EMOH	57	41	61	59	61	59	61	61	26	53	59	61	662
12. OPER BTU (GBTU)	130	133	236	528	533	678	668	742	272	649	706	345	5,629
13. NET GEN (MWH)	12,870	13,120	23,380	52,810	53,240	67,900	67,000	74,360	27,190	65,010	70,640	34,360	561,880
14. ANOHR (Btu/kwh)	10,122	10,117	10,079	10,007	10,002	9,981	9,975	9,981	9,988	9,977	9,994	10,033	10,018
15. NOF (%)	75.6	76.1	79.4	85.8	86.2	88.1	88.6	88.1	87.5	88.4	86.9	83.5	84.8
16. NPC (MW)	230	230	230	210	210	210	210	210	210	210	210	230	217
17. ANOHR EQUATION	ANOHR = NOF(	-11.267	) +		10,974								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2020 - DECEMBER 2020

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-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020
1. EAF (%)	97.1	97.1	68.9	80.9	68.9	97.1	97.1	97.1	68.0	81.5	68.0	97.1	84.9
2. POF	0.0	0.0	29.1	16.7	29.0	0.0	0.0	0.0	30.0	16.1	30.0	0.0	12.6
3. EUOF	2.9	2.9	2.0	2.4	2.0	2.9	2.9	2.9	2.0	2.4	2.0	2.9	2.5
4. EUOR	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	723	680	735	583	725	711	735	735	706	611	700	735	8,379
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	21	16	8	137	19	9	9	9	14	133	21	9	405
9. POH	0	0	216	120	216	0	0	0	216	120	216	0	1,104
10. EFOH	11	10	8	9	8	10	11	11	7	9	7	11	110
11. EMOH	11	10	8	9	8	10	11	11	7	9	7	11	110
12. OPER BTU (GBTU)	4,757	4,469	4,916	3,077	3,964	4,123	4,250	4,246	3,791	3,272	3,678	4,001	48,758
13. NET GEN (MWH)	687,400	644,830	723,940	409,440	541,220	593,630	610,220	608,910	510,640	439,810	488,080	505,080	6,763,200
14. ANOHR (Btu/kwh)	6,921	6,930	6,791	7,515	7,325	6,945	6,965	6,973	7,424	7,439	7,536	7,921	7,209
15. NOF (%)	79.2	79.0	82.1	66.2	70.4	78.7	78.2	78.1	68.2	67.8	65.7	57.3	72.9
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(	-45.556	) +		10,530								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2020 - DECEMBER 2020

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-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020
1. EAF (%)	98.1	94.7	63.3	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	60.1	91.7
2. POF	0.0	3.4	35.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.7	6.6
3. EUOF	1.9	1.8	1.2	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.1	1.7
4. EUOR	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	730	659	466	706	730	706	730	730	706	730	707	432	8,032
7. RSH	0	0	4	1	0	1	0	0	1	0	1	15	22
8. UH	14	37	273	13	14	13	14	14	13	14	13	297	730
9. POH	0	24	264	0	0	0	0	0	0	0	0	288	576
10. EFOH	4	3	2	4	4	4	4	4	4	4	4	2	42
11. EMOH	10	9	7	10	10	10	10	10	10	10	10	6	111
12. OPER BTU (GBTU)	3,243	2,701	2,033	3,132	3,304	3,299	3,417	3,466	3,318	3,351	3,168	2,045	36,494
13. NET GEN (MWH)	437,950	363,850	274,470	424,760	448,430	448,310	464,330	471,280	450,860	454,950	429,760	276,810	4,945,760
14. ANOHR (Btu/kwh)	7,404	7,422	7,408	7,374	7,369	7,360	7,359	7,355	7,358	7,365	7,371	7,389	7,379
15. NOF (%)	75.7	69.7	74.4	85.8	87.6	90.6	90.7	92.1	91.1	88.9	86.7	80.9	84.2
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(		-2.997	) +	7,631								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2020 - DECEMBER 2020

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-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020
1. EAF (%)	95.1	55.8	95.1	95.1	95.1	95.1	95.1	95.1	95.1	95.1	57.1	95.1	88.9
2. POF	0.0	41.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.9	0.0	6.6
3. EUOF	4.9	2.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	2.9	4.9	4.5
4. EUOR	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	392	130	471	674	707	684	707	707	684	698	366	707	6,927
7. RSH	316	258	236	11	1	1	1	1	1	10	46	1	882
8. UH	36	308	36	35	36	35	36	36	35	36	309	36	975
9. POH	0	288	0	0	0	0	0	0	0	0	288	0	576
10. EFOH	16	9	16	16	16	16	16	16	16	16	9	16	179
11. EMOH	20	11	20	19	20	19	20	20	19	20	12	20	220
12. OPER BTU (GBTU)	1,324	459	1,879	3,217	3,592	3,816	3,980	4,131	3,900	3,708	1,708	3,832	35,640
13. NET GEN (MWH)	172,180	59,800	245,980	428,000	479,980	513,330	535,850	557,770	525,600	497,050	226,890	510,090	4,752,520
14. ANOHR (Btu/kwh)	7,692	7,679	7,639	7,516	7,484	7,433	7,428	7,405	7,420	7,461	7,527	7,512	7,499
15. NOF (%)	42.0	43.9	49.9	68.4	73.1	80.8	81.6	84.9	82.7	76.7	66.7	68.9	70.9
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(-6.669) + 7,972

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GPIF 2020 PROJECTION
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ORIGINAL SHEET NO. 8.401.20E
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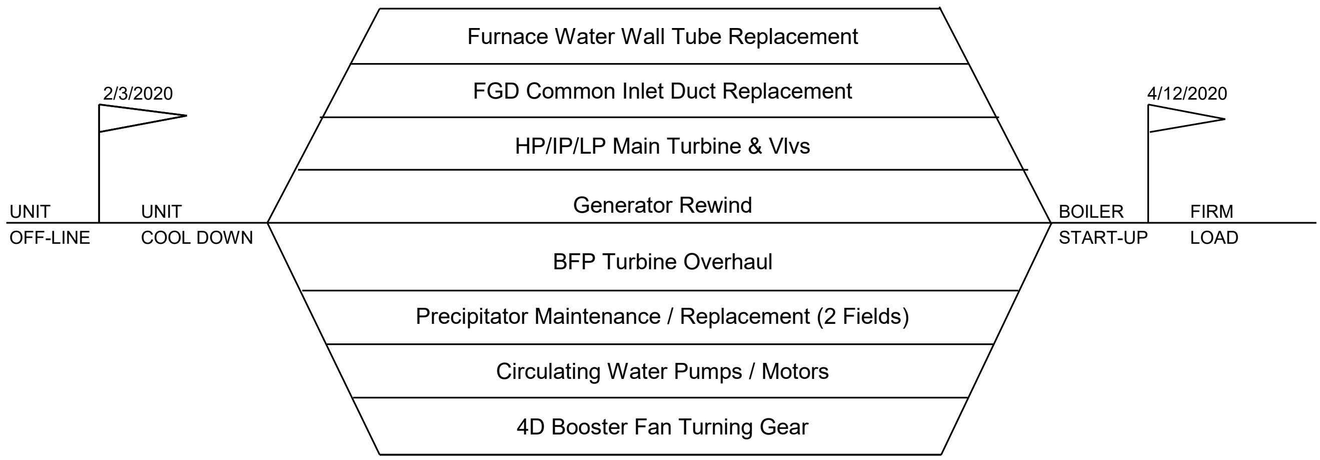
TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2020 - DECEMBER 2020

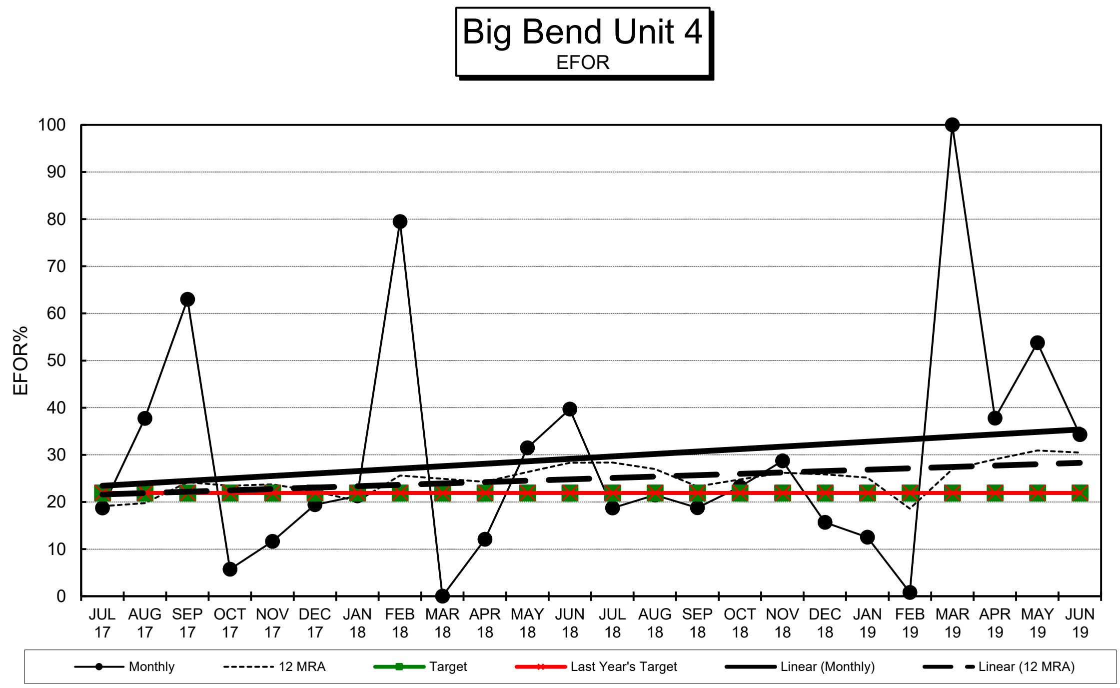
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
+	BIG BEND 4	Feb 03	-	Apr 12	Furnace Water Wall Tube Replacement, FGD Common Inlet Duct Replacement, Precipitator Maintenance, BFP Turbine Overhaul, 4D Booster Fan Turning Gear, Circulating Water Pumps / Motors, HP/IP/LP Main Turbine & Vlvs, Generator Rewind
		Nov 30	-	Dec 09	Fuel System Clean-up Planned Outage
	POLK 1	Jan 30	-	Feb 08	Combined Cycle & Gasifier Planned Outage
		Sep 14	-	Oct 04	Combined Cycle & Gasifier Planned Outage
	POLK 2	Apr 13	-	Apr 17	Combined Cycle Planned Outage
		Oct 23	-	Oct 27	Combined Cycle Planned Outage
	BAYSIDE 1	Feb 29	-	Mar 11	Combined Cycle Planned Outage
		Dec 02	-	Dec 13	Combined Cycle Planned Outage
	BAYSIDE 2	Feb 13	-	Feb 24	Combined Cycle Planned Outage
		Nov 12	-	Nov 23	Combined Cycle Planned Outage

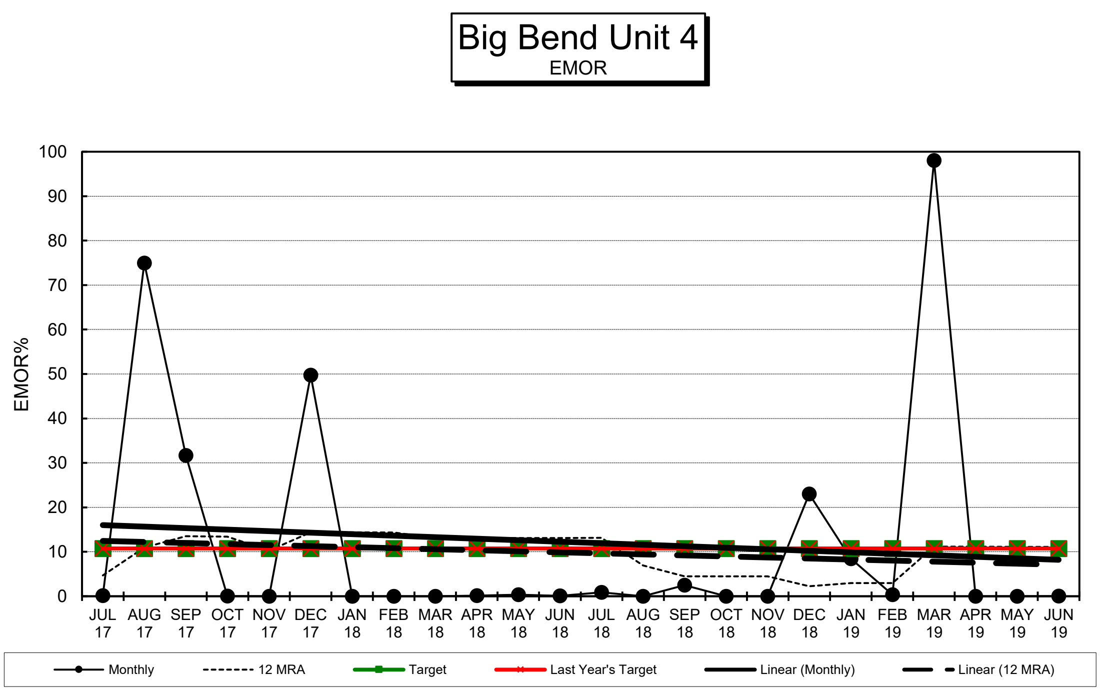
+ These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2020 - DECEMBER 2020



TAMPA ELECTRIC COMPANY
BIG BEND 4
PLANNED OUTAGE 2020
PROJECTED CPM


Big Bend Unit 4
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 4
EMOR
EMOR%
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JAN 19
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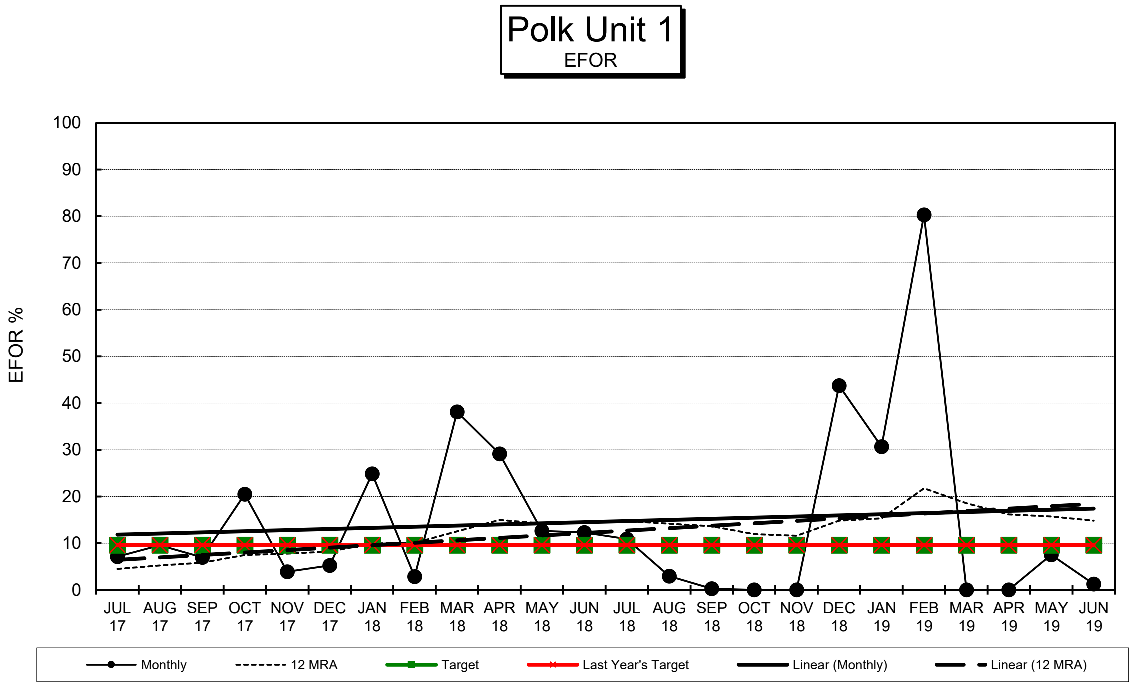
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR
EFOR %
100
90
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70
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JUL 17
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SEP 17
OCT 17
NOV 17
DEC 17
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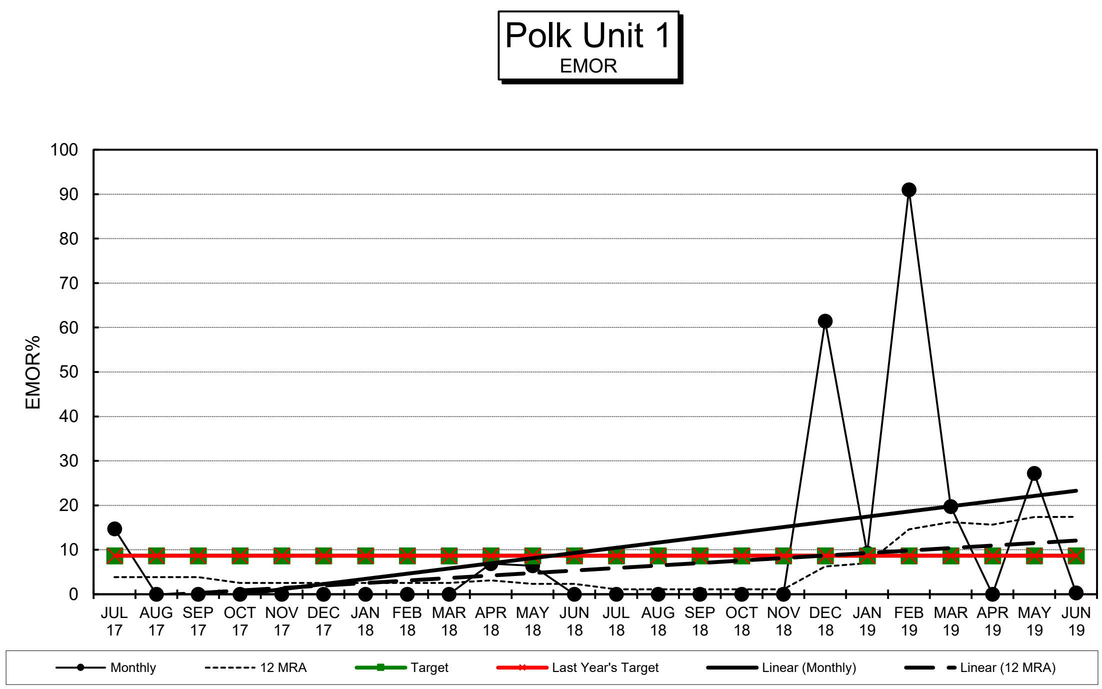
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EMOR
EMOR%
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NOV 17
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DEC 18
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MAR 19
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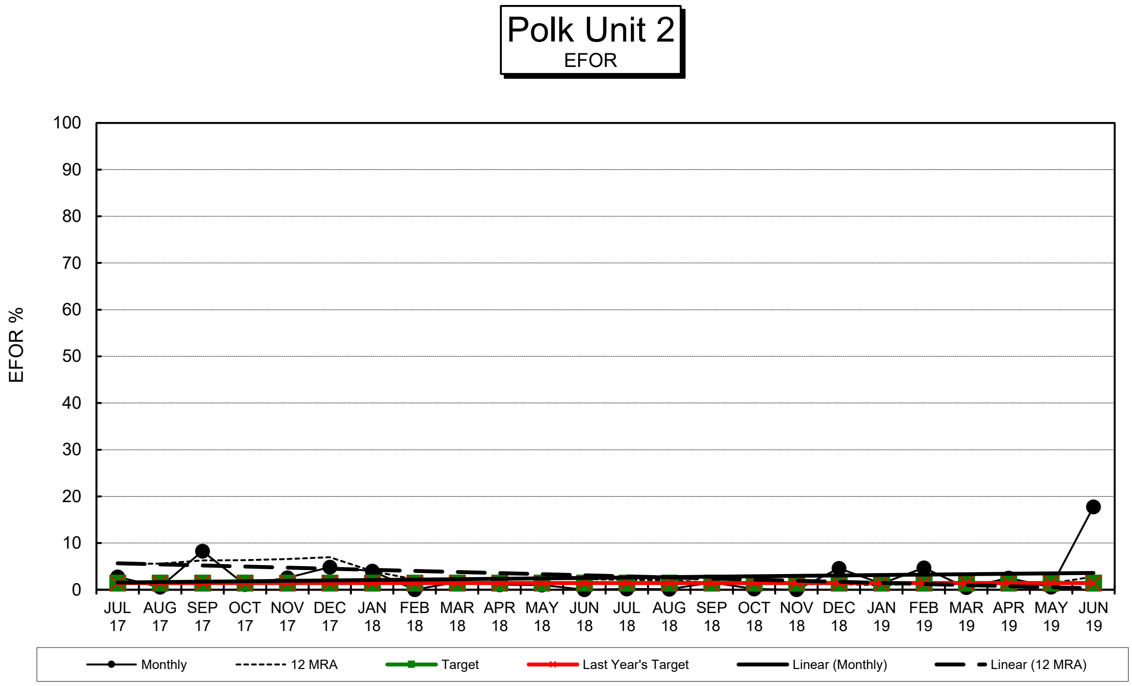
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR %
100
90
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70
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AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
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DEC 18
JAN 19
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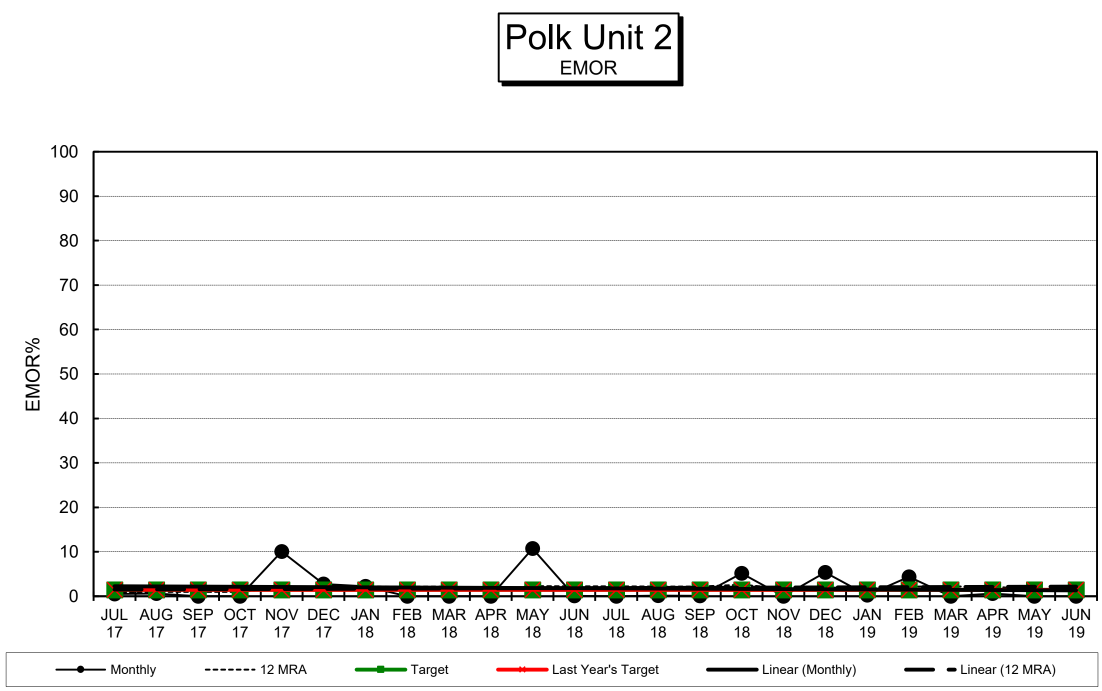
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 2
EMOR
EMOR%
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AUG 17
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NOV 17
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NOV 18
DEC 18
JAN 19
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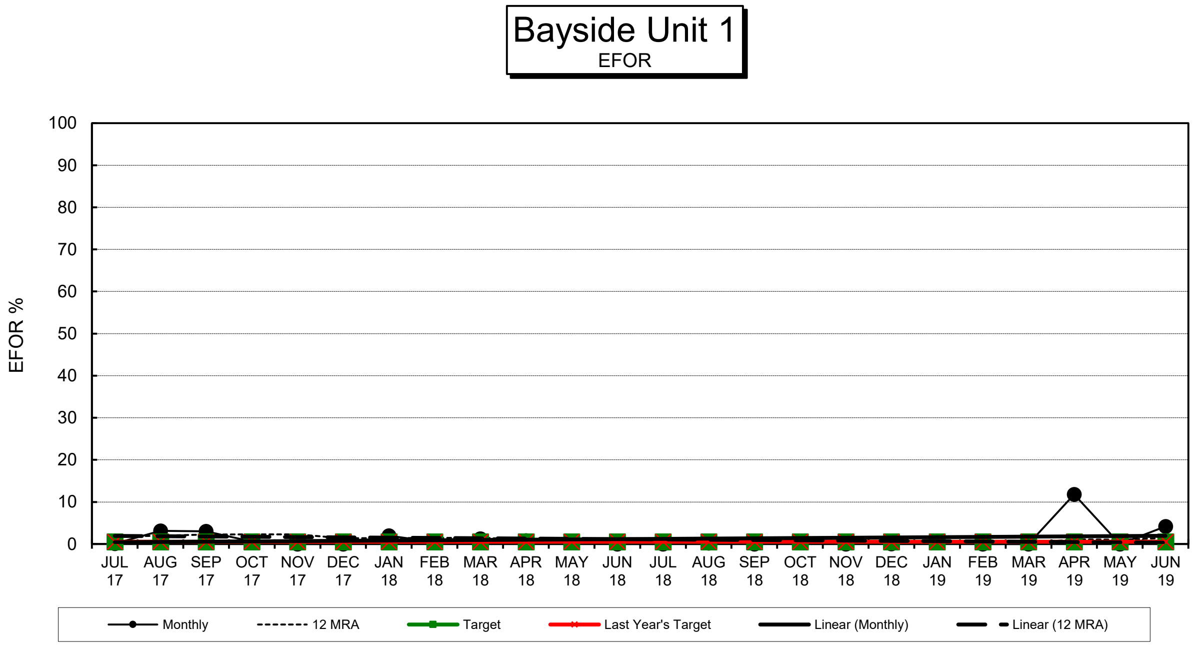
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EFOR
EFOR %
100
90
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70
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AUG 17
SEP 17
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NOV 17
DEC 17
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OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
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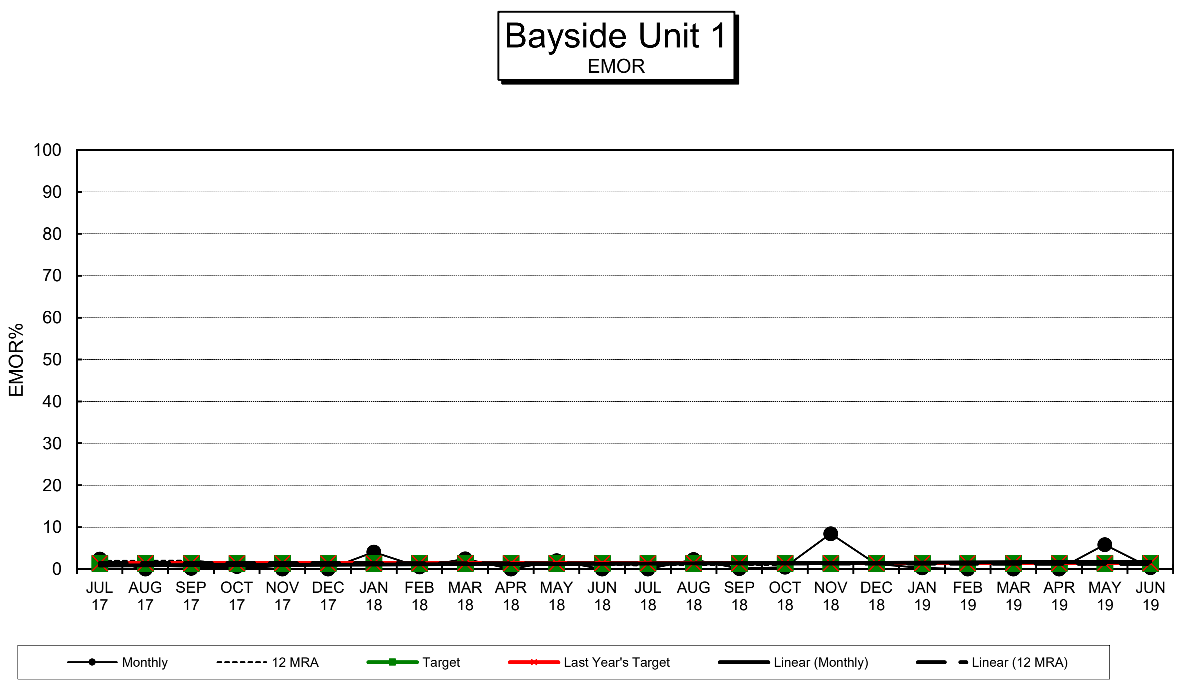
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EMOR
EMOR%
100
90
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DEC 18
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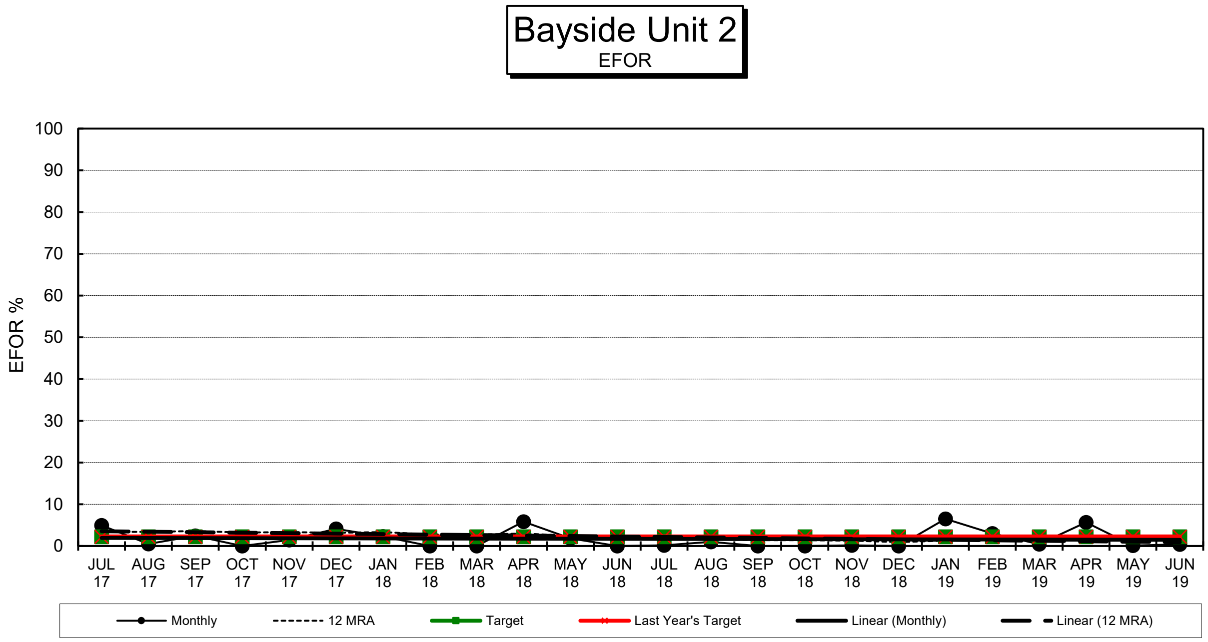
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EFOR
EFOR %
100
90
80
70
60
50
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10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
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DEC 18
JAN 19
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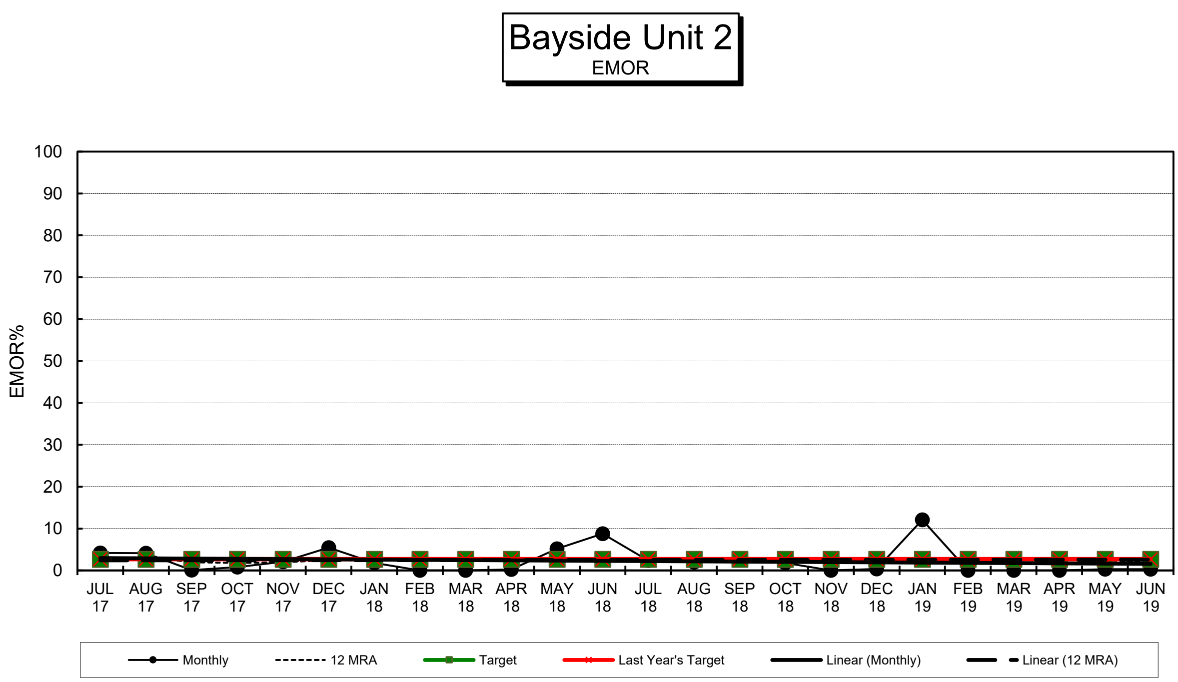
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EMOR
EMOR%
100
90
80
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JUL 17
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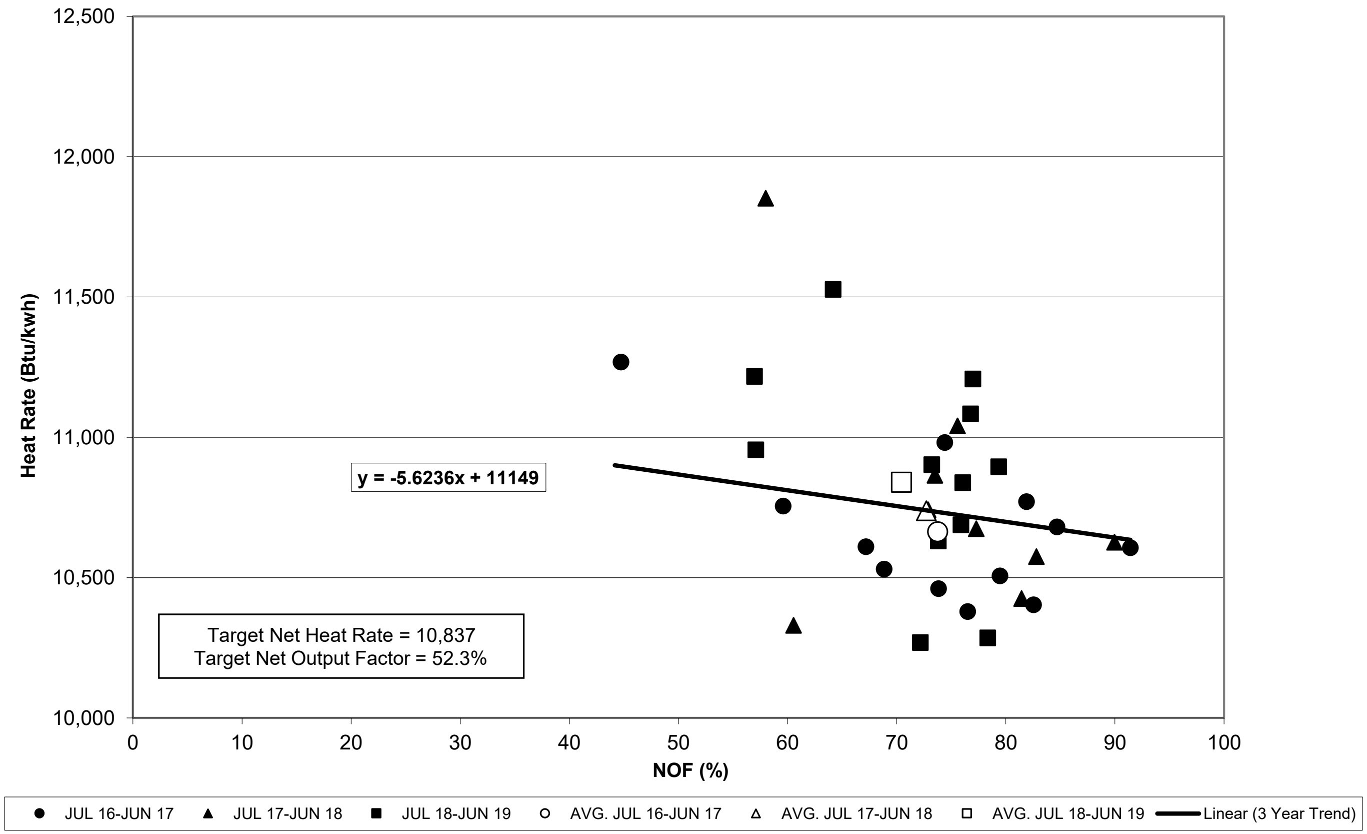
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

43

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



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GPIF 2020 PROJECTION
EXHIBIT NO. JC-1, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.20E
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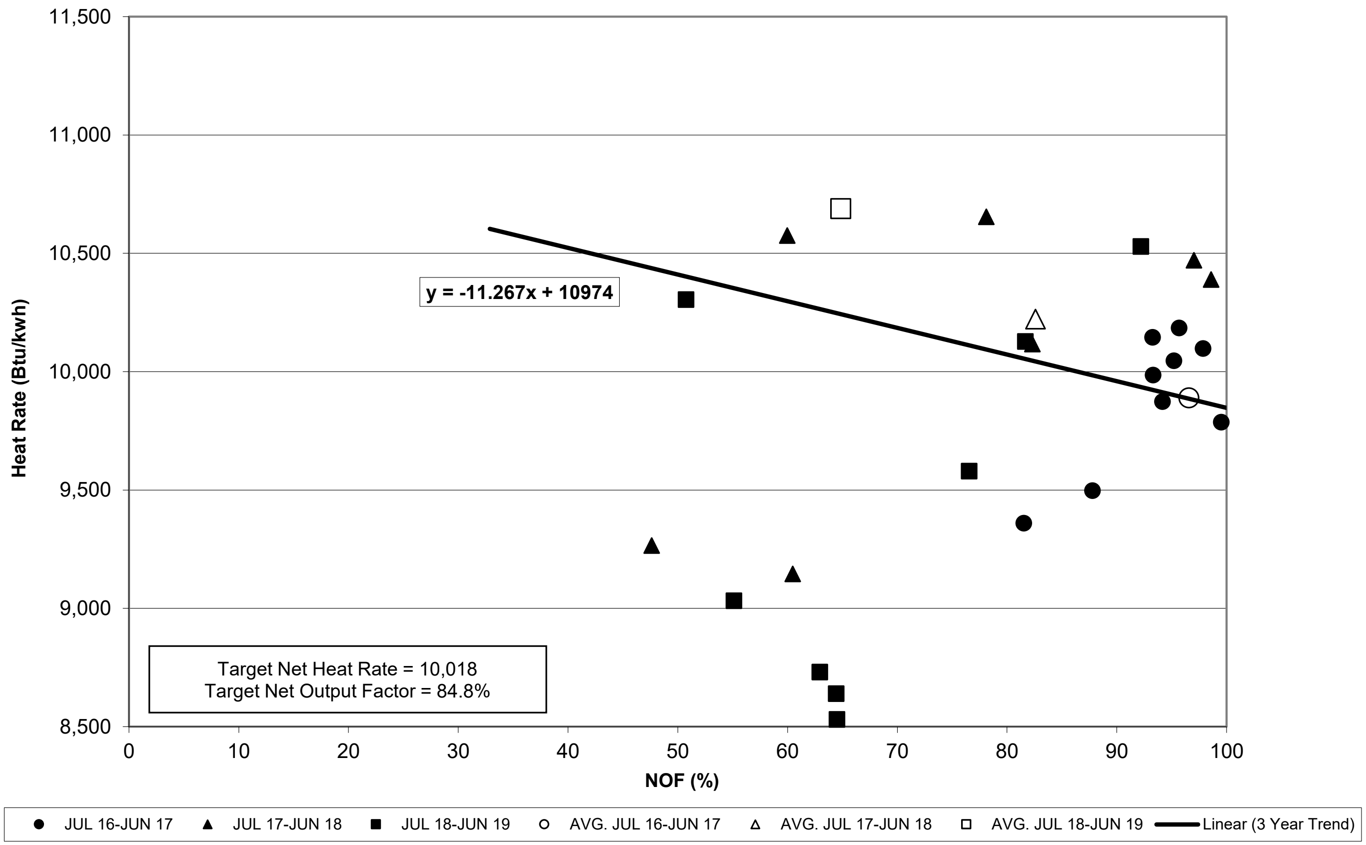
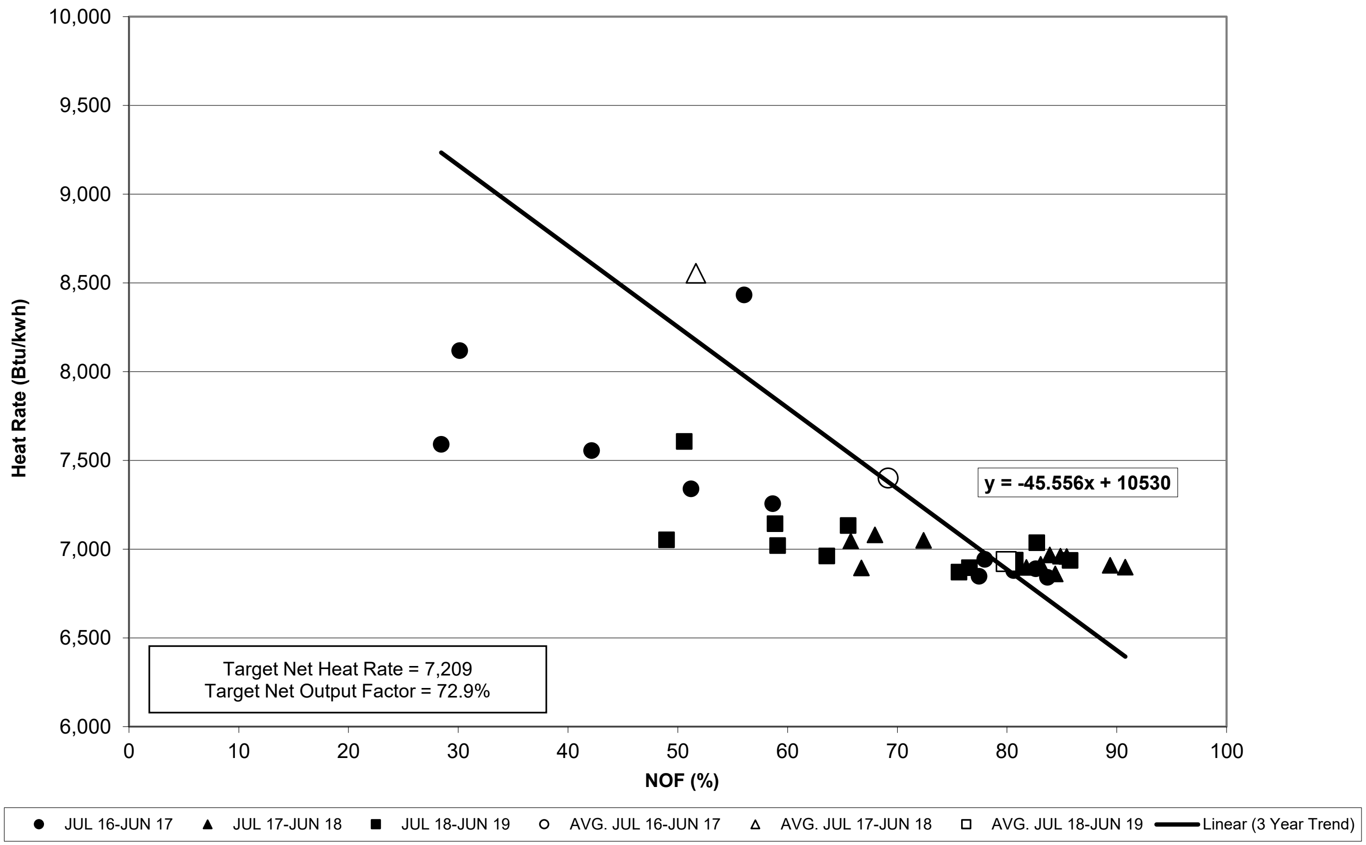
Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1



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



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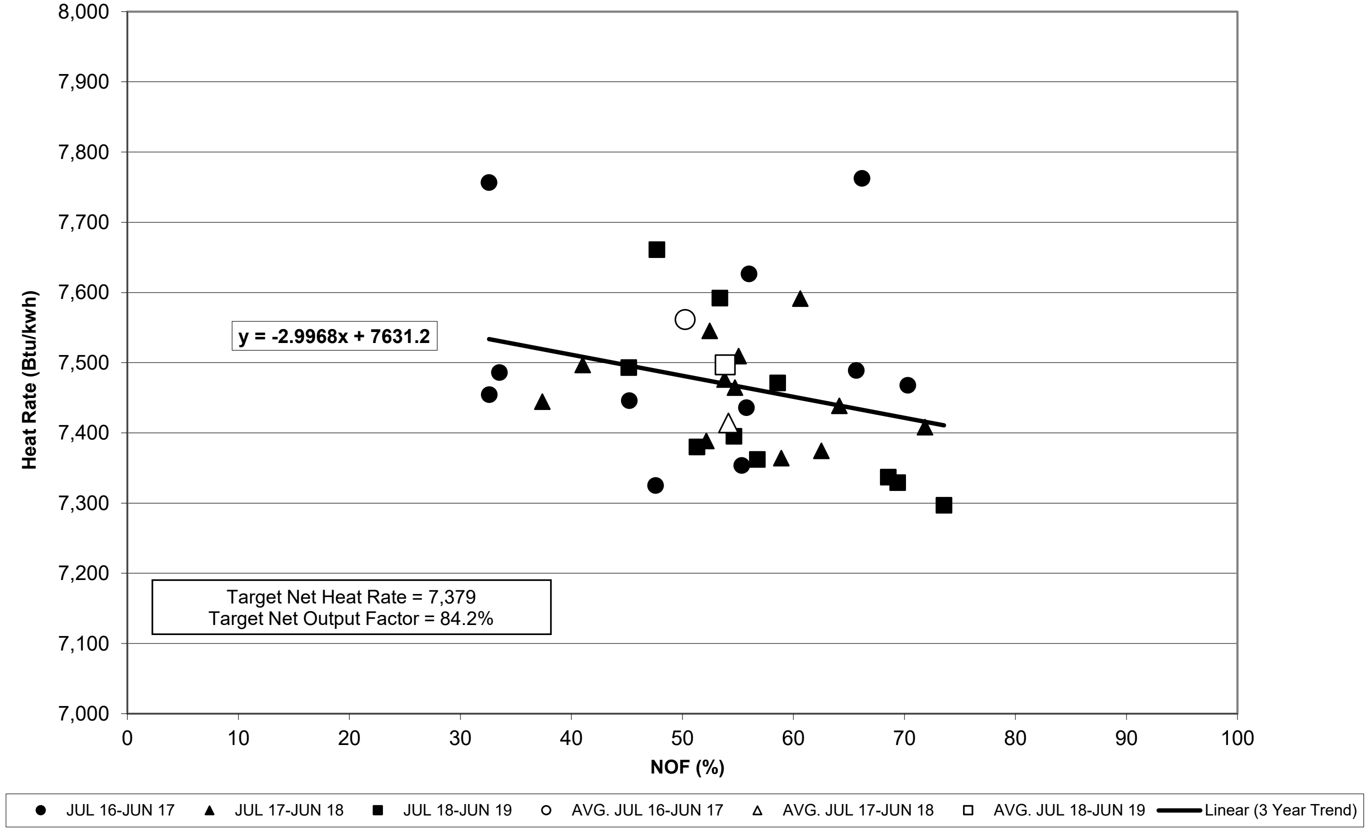
Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1



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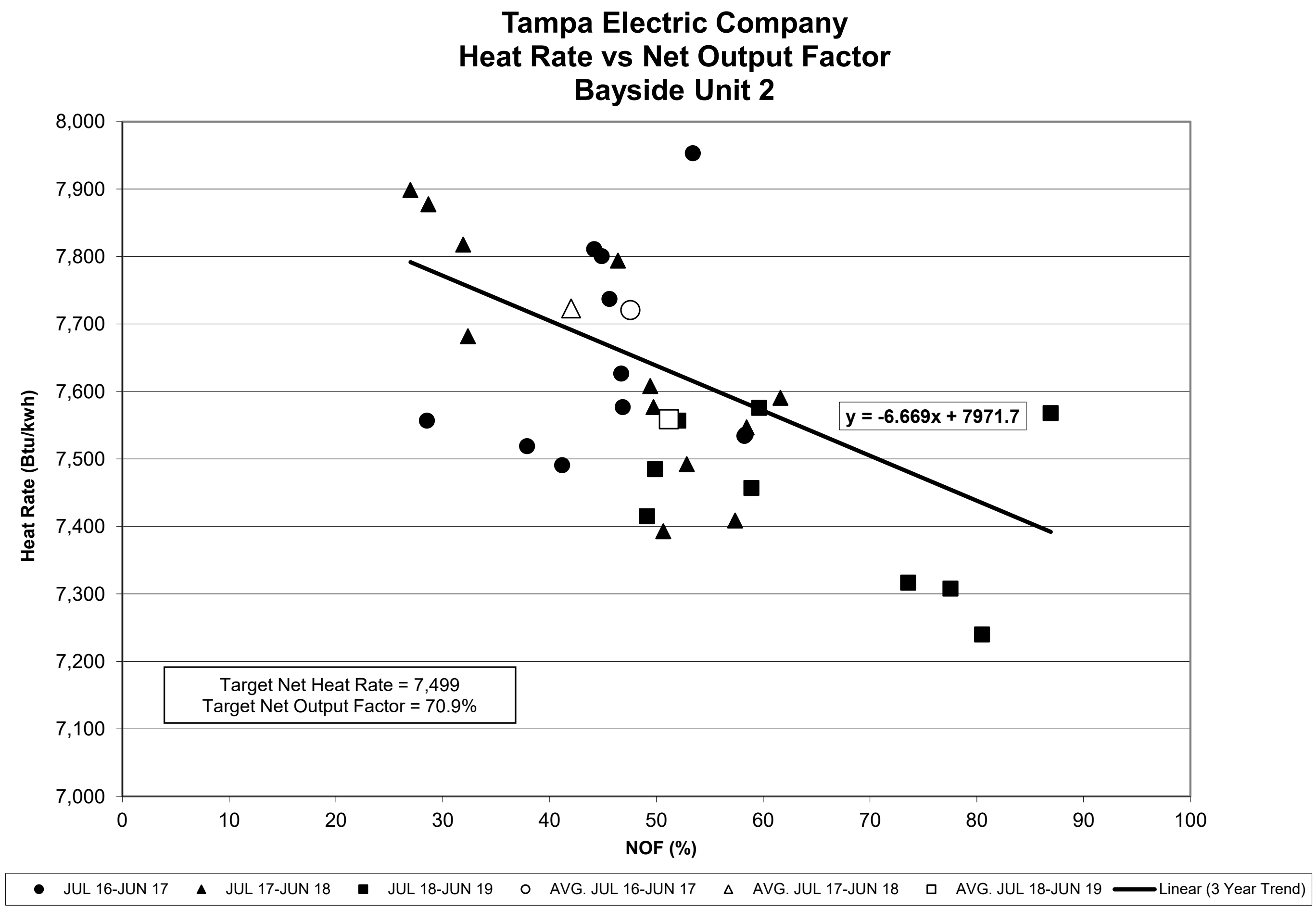

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PAGE 28 OF 31

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2020 - DECEMBER 2020

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 4		382	349
POLK 1		225	217
POLK 2		1,130	1,107
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,456	3,372
	SYSTEM TOTAL	**5,249**	**5,105**
	% OF SYSTEM TOTAL	**65.8%**	**66.1%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2020 - DECEMBER 2020

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		323	308
BIG BEND 2		363	343
BIG BEND 3		368	348
BIG BEND 4		382	349
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,495	1,406
POLK 1		225	217
POLK 2		1,130	1,107
	POLK TOTAL	1,355	1,324
SOLAR		445	445
	SOLAR TOTAL	445	445
	SYSTEM TOTAL	**5,249**	**5,105**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2020 - DECEMBER 2020

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
POLK	2	6,763,200	33.31%	33.31%
BAYSIDE	1	4,945,760	24.36%	57.66%
BAYSIDE	2	4,752,520	23.40%	81.07%
SOLAR		1,413,420	6.96%	88.03%
BIG BEND	4	708,280	3.49%	91.51%
POLK	1	561,880	2.77%	94.28%
BIG BEND	3	531,060	2.62%	96.90%
BIG BEND	2	310,710	1.53%	98.43%
BIG BEND	1	183,340	0.90%	99.33%
BAYSIDE	5	40,470	0.20%	99.53%
BAYSIDE	6	34,740	0.17%	99.70%
BAYSIDE	3	28,310	0.14%	99.84%
BAYSIDE	4	19,010	0.09%	99.93%
BIG BEND CT	4	13,510	0.07%	100.00%
TOTAL GENERATION		20,306,210	100.00%	

GENERATION BY COAL UNITS: 708,280 MWH

% GENERATION BY COAL UNITS 3.49%

GENERATION BY SOLAR UNITS: 1,413,420 MWH

% GENERATION BY SOLAR UNIT 6.96%

GENERATION BY NATURAL GAS UNITS: 18,184,510 MWH

% GENERATION BY NATURAL GAS UNITS: 89.55%

GENERATION BY GPIF UNITS: 17,731,640 MWH

% GENERATION BY GPIF UNITS: 87.32%

EXHIBIT TO THE TESTIMONY

OF

JEREMY B. CAIN

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2020 - DECEMBER 2020

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2020 - DECEMBER 2020

	Availability			Net
Unit	**EAF**	**POF**	**EUOF**	**Heat Rate**
Big Bend 4[1]	55.4	21.8	22.8	10,837
Polk 1[2]	75.5	8.5	16.0	10,018
Polk 2[3]	84.9	12.6	2.5	7,209
Bayside 1[4]	91.7	6.6	1.7	7,379
Bayside 2[5]	88.9	6.6	4.5	7,499

1 Original Sheet 8.401.20E, Page 12

2 Original Sheet 8.401.20E, Page 13

3 Original Sheet 8.401.20E, Page 14

4 Original Sheet 8.401.20E, Page 15

5 Original Sheet 8.401.20E, Page 16

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20190001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2020 THROUGH DECEMBER 2020

TESTIMONY

OF

JOHN C. HEISEY

FILED: SEPTEMBER 3, 2019

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 Manager, Gas and Power Trading.

Q. Have you previously filed testimony in Docket No. 20190001-EI?

A. Yes, I submitted direct testimony on March 1, 2019.

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

A. No, it has not.

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 fuel mix includes natural gas, coal, solar, and, as a backup fuel, oil. Big Bend Units 1 and 2 can operate on natural gas, and Big Bend Units 3 and 4 can operate on coal or natural gas. Polk Unit 1 can operate on a blend of petroleum coke and coal or on natural gas. Currently, the company is operating Big Bend Units 1 through 3 and 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. During 2019, continued low natural gas prices equate to lower fuel prices for customers. Based upon the 2019 actual-estimate projections, the company expects 2019 total system generation, excluding purchased power, to be 90 percent natural gas, 6 percent coal, and 4 percent solar.

Likewise, in 2020, natural gas-fired and coal-fired generation are expected to be 89 percent and 4 percent of total generation, respectively, with solar facilities making up 7 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 credit worthy 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.

Coal Supply Strategy

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

A. The steam turbine units at Big Bend Station are designed to burn high-sulfur Illinois Basin coal and are fully scrubbed for sulfur dioxide and nitrogen oxides, and the units have 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 Tampa Electric select its fuel based on multiple parameters. Those parameters include unique coal characteristics, price, availability, deliverability, and credit worthiness 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 2020.

A. Since the company is projected to use less coal and more natural gas in 2020 compared to previous years, Tampa Electric will supply the Big Bend and Polk Stations with solid fuel through a combination of existing inventory, short-term contracts and spot purchases. The 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.

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.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2019 and 2020?

A. Yes. Tampa Electric expects to receive coal for use at

Big Bend Station through the Big Bend rail facility during 2019 and is evaluating how much coal to receive by rail in 2020.

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

A. Tampa Electric expects to receive solid fuel supply from waterborne deliveries to its unloading facilities at Big Bend Station. These deliveries come via the Mississippi River System through United Bulk Terminal 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. The continued trend of an abundant volume of natural gas available at historically low prices results in Tampa Electric's continued use of natural gas in the dual-fueled Big Bend and Polk units. In addition, the company's strategy of utilizing short-term and spot solid fuel purchases allows Tampa Electric to reduce its solid fuel deliveries going forward, which aligns well with the economical use of natural gas. As a result, Tampa Electric will contract for fewer tons of solid fuel supply and transportation in the remainder of 2019 and 2020 than in previous years.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2020 solid fuel supply portfolio.

A. Tampa Electric continues to place emphasis on flexibility in its solid fuel supply portfolio. The company recognizes that several factors may impact the annual consumption of solid fuel. These factors include the relative price of delivered solid fuel compared to the delivered natural gas and wholesale power markets. Thus, the actual quantity of solid fuel burned may vary significantly each year. In developing its solid fuel portfolio, Tampa Electric strives to balance the need to have reliable solid fuel commodity supplies and transportation while mitigating the potential for significant shortfall penalties if the commodity or transportation is not needed.

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. Like its coal strategy, 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 and maintain the ability to take advantage of favorable natural gas price movements. Tampa Electric purchases its physical natural gas supply from creditworthy counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. 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 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 in order to mitigate costs to its customers.

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

A. Tampa Electric currently receives natural gas via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. Tampa Electric has added the ability to receive a portion of its gas via the recently constructed Sabal Trail Transmission ("Sabal Trail") gas pipeline. The ability to deliver natural gas directly 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 (via Gulfstream backhaul) to support the station's steam generating units and aero-derivative combustion turbine. Polk Station receives natural gas from FGT to support Polk Unit 2 and, as an alternate fuel, Polk Unit 1. The addition of Sabal Trail to the company's delivery options enhances reliability, supply, price, and location diversity.

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

A. Tampa Electric's natural gas usage is expected to remain stable in 2020. The strategy of burning economical natural gas in dual-fueled units continues to provide lower overall costs to customers.

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 to provide operational flexibility and reliability of natural gas supply. The company reserves 2,000,000 MMBtu of long-term storage capacity in two locations.

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") and Transco's Mobile Bay Lateral ("Transco"). SESH 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 and Transco capacity give Tampa Electric access to secure, competitively priced onshore gas supply for a portion of its portfolio.

Q. Has Tampa Electric acquired additional natural gas transportation for 2019 and 2020 due to greater use of natural gas?

A. Yes, with the continued low price of natural gas and the company's growing demand for natural gas for electric generation purposes, the company acquires daily, seasonal and longer-term pipeline capacity to support the company's portfolio of gas-fired generation assets. In particular, in 2019, Tampa Electric acquired 20,000 MMBtu per day of additional seasonal pipeline capacity, on Sabal Trail. This capacity provides additional diversification of pipelines and gas supply receipt points.

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. Have there been other changes in the management of Tampa Electric's 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, 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 2020 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"), PIRA Energy, 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 in May 2019, 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 prices and coal transportation prices are projected using contracted pricing and information from industry recognized consultants and published indices, such as Doyle Trading Consultants and *Coal Daily*. Also, the price projections are specific to the particular quality and mined location of coal utilized by Tampa Electric's Big

Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2020 projected fuel prices compare to the fuel prices projected for 2019 in the company’s mid-course correction filing?

A. Large quantities of domestic shale-related production are keeping natural gas prices low. The commodity price for natural gas during 2020 is projected to be lower ($2.77 per MMBtu) than the 2019 price ($3.29 per MMBtu) projected in the company’s mid-course correction fuel filing. Coal prices, however, are trending higher. The 2020 coal commodity price projection is slightly higher ($39.52 per ton) than the price projected for 2019 ($37.81 per ton) during preparation of the 2019 mid-course correction fuel clause factors. International demand for coal is elevating coal prices despite minimal domestic demand.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20190001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2020 THROUGH DECEMBER 2020

TESTIMONY

OF

BENJAMIN F. SMITH II

FILED: SEPTEMBER 3, 2019

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") in the Wholesale Marketing Group within the Wholesale Marketing & Fuels 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 in the Wholesale Marketing, Planning and Fuels 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 by-product contract administration and market opportunities. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, and other wholesale developers and independent power producers.

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 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 the company has entered into 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, 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 March 11, 1997 Order, No. PSC-1997-0262-FOF-EI, 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 2019 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 six percent of the company's expected needs for 2019 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) and the Florida Municipal Power Agency (FMPA).

Tampa Electric contracted to purchase non-firm energy from DEF for the period February 2019 through February 2020. Tampa Electric must take the energy during the months of June through October and has the option to take energy during the other months. The contract also provides flexibility to Tampa Electric to increase its purchase volume at times, which benefits customers as an economic option at times of high demand or during unit outages. The DEF purchase agreement provides savings to customers that flow through the company's optimization mechanism, which are described in the annual actual fuel docket reporting and accompanying testimony of Tampa Electric witness John C. Heisey.

Tampa Electric entered a purchase agreement for non-firm energy with FMPA for the period May 2019 through October 2019. The FMPA purchase also provides savings to customers through the company's optimization mechanism.

Tampa Electric has not secured other forward purchases for 2019 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 2020 and beyond?

A. Similar to 2019, the company anticipates entering into new short-term power purchases for 2020. Furthermore, Tampa Electric will continue to evaluate its options beyond 2020 as well. The company's evaluation includes the review of new short- and long-term capacity and energy purchases and considers existing and anticipated system and market conditions. The goal of the evaluation is to identify and, if possible, secure, economic purchases that bring value to customers for the year 2020 and beyond. Currently, Tampa Electric expects purchased power to meet approximately one percent of its 2020 energy needs.

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 applicable, 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 2019 and 2020.

A. Tampa Electric entered into various non-separated wholesale sales in 2019, and the company anticipates making additional non-separated sales during the balance of 2019 and 2020. The gains from these sales are distributed to Tampa Electric and its customers in accordance with 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 into wholesale sales that benefit customers when market conditions allow.

Q. Does this conclude your direct testimony?

A. Yes, it does.