FILED 11/7/2018
DOCUMENT NO. 07009-2018
FPSC - COMMISSION CLERK

Docket No. 20180133-EI
Comprehensive Exhibit List for Entry into Hearing Record
October 29, 2018

EXH #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
TAMPA ELECTRIC COMPANY– (DIRECT)					
2	Mark D. Ward	MDW-1	Lithia Solar Project Specifications and Projected Costs; Grange Hall Solar Project Specifications and Projected Costs; Peace Creek Solar Project Specifications and Projected Costs; Bonnie Mine Project Specifications and Projected Costs; Lake Hancock Project Specifications and Projected Costs **Confidential DN. 04479-2018**	1, 2, 3, 4, 5, 7	
3	R. James Rocha	RJR-1[1]	Demand and Energy Forecasts; Fuel Price Forecast; Revenue Requirements for Second SoBRA; Cost-effectiveness Tests for Second SoBRA	1, 2, 5, 7	

[1] Exhibits RJR-1 Revised August 8, 2018

4	William R. Ashburn	WRA-1[2]	Development of Second SoBRA Base Revenue Increase by Rate Class; Base Revenue by Rate Schedule; Rollup Base Revenue by Rate Class; Typical Bills Reflecting Second SoBRA Base Revenue Increase; Determination of Fuel Recovery Factor for Second SoBRA; Redlined Tariffs Reflecting Second SoBRA Base Revenue Increase; Clean Tariffs Reflecting Second SoBRA Base Revenue Increase	1, 6, 7	
STAFF – (DIRECT)					
5	James Rocha 1, 10-17, 23-28 Mark Ward 2-9, 13, 18, 20-22 William Ashburn 19		Staff's First Data Request[3] Nos. 1 – 28 **Supplemental Response to No. 23** **(See additional files contained on Staff Hearing Exhibit CD/USB for 1, 10, 11, 15-17, and 19.)** **Confidential DN. 05029-2018 (No. 26)** *[Bates Nos. 00001-00057]*	1, 2, 3, 4, 5, 6, 7	
6	James Rocha 1, 5-7 Mark Ward 2-4 William R. Ashburn 8-11		Staff's First Data Request "Production of Documents"[4] Nos. 1 – 11 **Confidential DN. 05032-2018 (Nos. 2, 3, 6)** *[Bates Nos. 00058-000176]*	1, 2, 3, 4, 5, 6, 7	

[2] Exhibit WRA-1 1st Revision July 5, 2018. 2nd Revision September 24, 2018.
[3] Document No. 04746-2018, filed on July 18, 2018, in Docket No. 20180133-EI.
[4] Id.

7	James Rocha		Staff's Second Data Request[5] Nos. 27 – 38 **(See additional files contained on Staff Hearing Exhibit CD/USB for 28.)** *[Bates Nos. 00177-00190]*	1, 2, 5, 6, 7	
8	James Rocha		Staff's 1st Interrogatories Nos. 1 – 5 **Confidential DN. 05478-2018 (Nos. 1 and 5)** *[Bates Nos. 00191-00211]*	2	
9	James Rocha		Staff's 1st POD, No. 1 **Confidential DN. 05481-2018 (No. 1)** *[Bates Nos. 00212-00220]*	2	
10	James Rocha 6, 9, 11, 12, 14, 17 Mark Ward 7, 8, 10, 13, 15, 16		Staff's 2nd Interrogatories Nos. 6-17 **Supplemental Response to Nos. 11 & 12** **2nd Supplemental Response to No. 12** **(See additional files contained on Staff Hearing Exhibit CD/USB for 12, 14 and 17.)** **Confidential DN. 06034-2018 (No. 10)** *[Bates Nos. 00221-00248]*	1, 2, 3, 4, 5, 6, 7	

[5] Document No. 04813-2018, filed on July 23, 2018, in Docket No. 20180133-EI.

HEARING EXHIBITS					
Live Exhibit Number	**Witness**	**Party**	**Description**		**Moved In/Due Date of Late Filed**
11		All	Stipulations		

TAMPA ELECTRIC COMPANY
DOCKET NO. 2018_______ -EI
EXHIBIT NO.______(MDW-1)

EXHIBIT

OF

MARK D. WARD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180133-EI EXHIBIT: 2
PARTY: TAMPA ELECTRIC COMPANY–
(DIRECT)
DESCRIPTION: Mark D. Ward MDW-1

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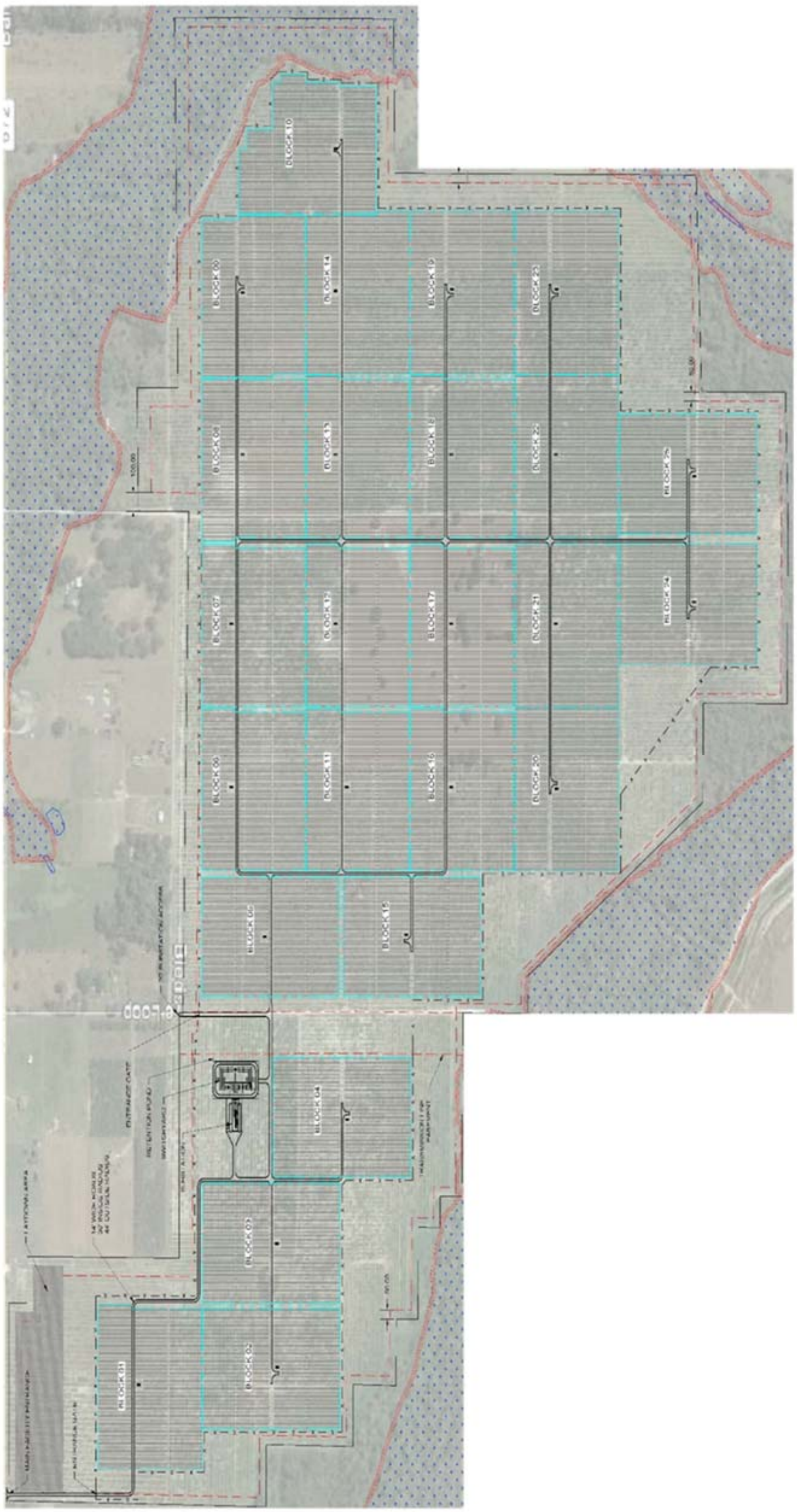
Lithia Solar Project Specifications

Specifications of Proposed Solar PV Generating Facilities

(1)	Plant Name and Unit Number	Lithia Solar
(2)	Net Capability	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	June 2017
	B. Commercial In-Service Date	January 2019
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+580 Acres
(9)	Construction Status	In Progress
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2018)	26.5 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (ANOHR) [1]	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	1,494.17
	Direct Construction Cost ($/kW)	1,460.43
	AFUDC Amount ($/kW) [2]	33.74
	Escalation ($/kW)	N/A
	Fixed O&M ($/kW – yr)	7.34
	Variable O&M ($/MWh)	0.0
	K-Factor [3]	1.12

1 Includes interconnect, AFUDC, land, w/o incentive
2 Based on the current AFUDC rate of 6.46%
3 W/o land

Lithia Solar Project General Arrangement Drawing



Lithia Solar Project Projected Installed Cost by Category

Lithia Solar Estimated Costs ($MM)	
Project Output (MW-ac)	74.5
Major Equipment[1]	[redacted]
Balance of System[2]	[redacted]
Development	2.4
Transmission Interconnect	4.0
Land	13.8
Owners Costs	0.9
Total Installed Cost ($MM)	108.8
AFUDC ($MM)	2.5
Total All-in-Cost ($MM)	111.3
Total ($/kW-ac)	1,494

[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

Grange Hall Solar Project Specifications

Specifications of Proposed Solar PV Generating Facilities

(1)	Plant Name and Unit Number	Grange Hall Solar
(2)	Net Capability	61.1 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	June 2017
	B. Commercial In-Service Date	January 2019
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+447 Acres
(9)	Construction Status	In Progress
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2018)	26.06 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	1,437.52
	Direct Construction Cost ($/kW)	1,420.87
	AFUDC Amount ($/kW) [2]	16.64
	Escalation ($/kW)	N/A
	Fixed O&M ($/kW – yr)	7.34
	Variable O&M ($/MWh)	0.0
	K-Factor [3]	1.12

1 Includes interconnect, AFUDC, land w/o incentive
2 Based on the current AFUDC rate of 6.46%
3 W/o land

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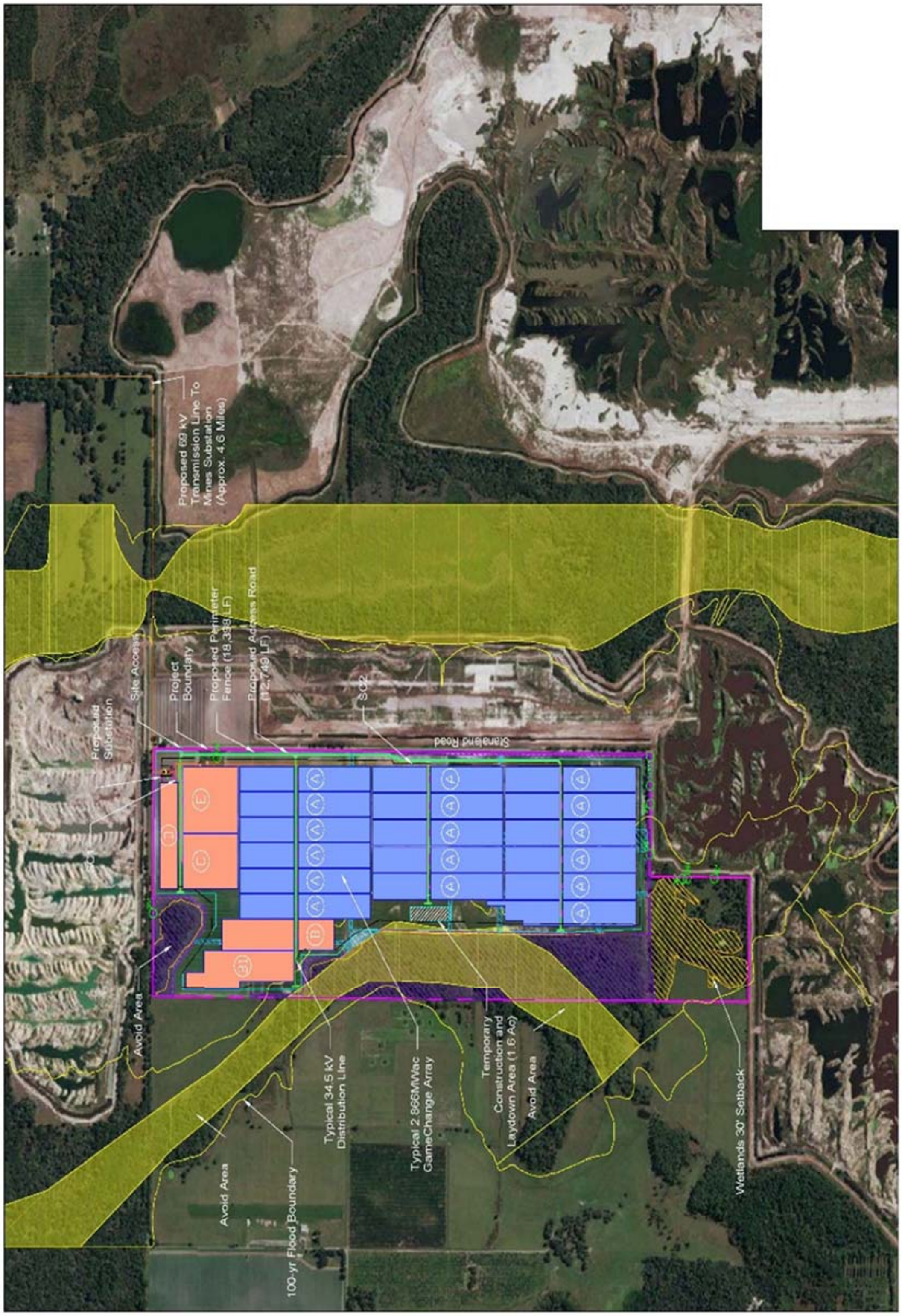
Grange Hall Solar Project General Arrangement Drawing



Grange Hall Solar Project Projected Installed Cost by Category

Estimated Costs ($MM)	
Project Output (MW-ac)	61.1
Major Equipment[1]	[redacted]
Balance of System[2]	[redacted]
Development	1.8
Transmission Interconnect	4.6
Land	8.4
Owners Costs	0.5
Total Installed Cost ($MM)	86.8
AFUDC ($MM)	1.0
Total All-in-Cost ($MM)	87.8
Total ($/kW-ac)	1,437

[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

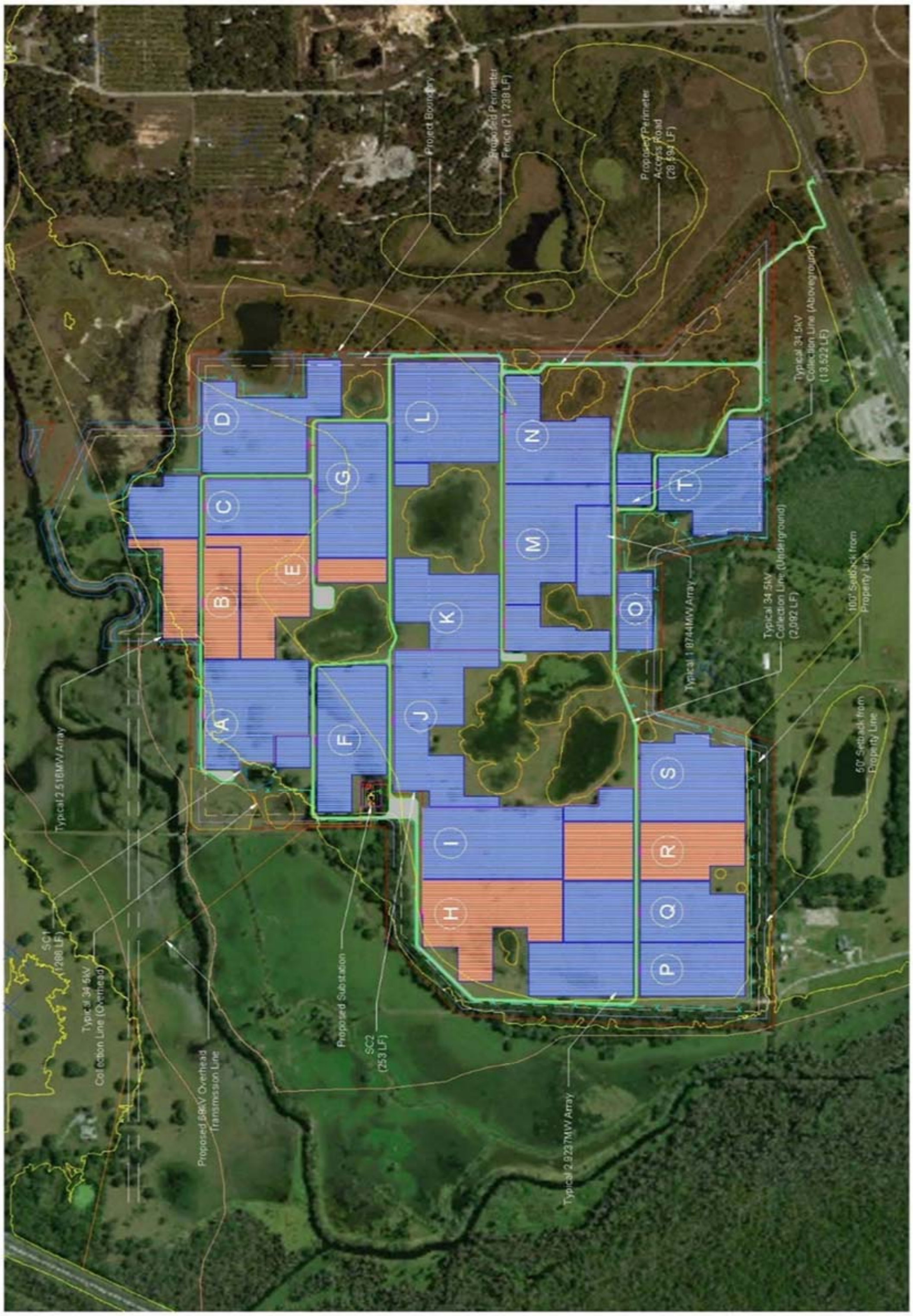
Peace Creek Solar Project Specifications

Specifications of Proposed Solar PV Generating Facilities

(1)	Plant Name and Unit Number	Peace Creek Solar
(2)	Net Capability	55.4 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	September 2017
	B. Commercial In-Service Date	January 2019
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+417 Acres
(9)	Construction Status	In Progress
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2018)	26.27 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (ANOHR) [1]	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	1,491.62
	Direct Construction Cost ($/kW)	1,466.99
	AFUDC Amount ($/kW) [2]	24.62
	Escalation ($/kW)	N/A
	Fixed O&M ($/kW – yr)	7.34
	Variable O&M ($/MWh)	0.0
	K-Factor [3]	1.12

1 Includes interconnect, AFUDC, land, w/o incentive
2 Based on the current AFUDC rate of 6.46%
3 W/o land

Peace Creek Solar Project General Arrangement Drawing



Peace Creek Solar Project Projected Installed Cost by Category

Estimated Costs ($MM)	
Project Output (MW-ac)	55.4
Major Equipment[1]	[redacted]
Balance of System[2]	[redacted]
Development	1.8
Transmission Interconnect	4.7
Land	11.7
Owners Costs	0.4
Total Installed Cost ($MM)	81.3
AFUDC ($MM)	1.4
Total All-in-Cost ($MM)	82.6
Total ($/kW-ac)	1,492

[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

Bonnie Mine Solar Project Specifications

Specifications of Proposed Solar PV Generating Facilities

(1)	Plant Name and Unit Number	Bonnie Mine Solar
(2)	Net Capability	37.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	November 2017
	B. Commercial In-Service Date	January 2019
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+352 Acres
(9)	Construction Status	In Progress
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2018)	27.2% (1st Full Yr Operation)
	Average Net Operating Heat Rate (ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	1,464.15
	Direct Construction Cost ($/kW)	1,442.28
	AFUDC Amount ($/kW) [2]	21.87
	Escalation ($/kW)	N/A
	Fixed O&M ($/kW – yr)	7.52
	Variable O&M ($/MWh)	0.0
	K-Factor [3]	1.12

1 Includes interconnect, AFUDC, land w/o incentive
2 Based on the current AFUDC rate of 6.46%
3 W/o land

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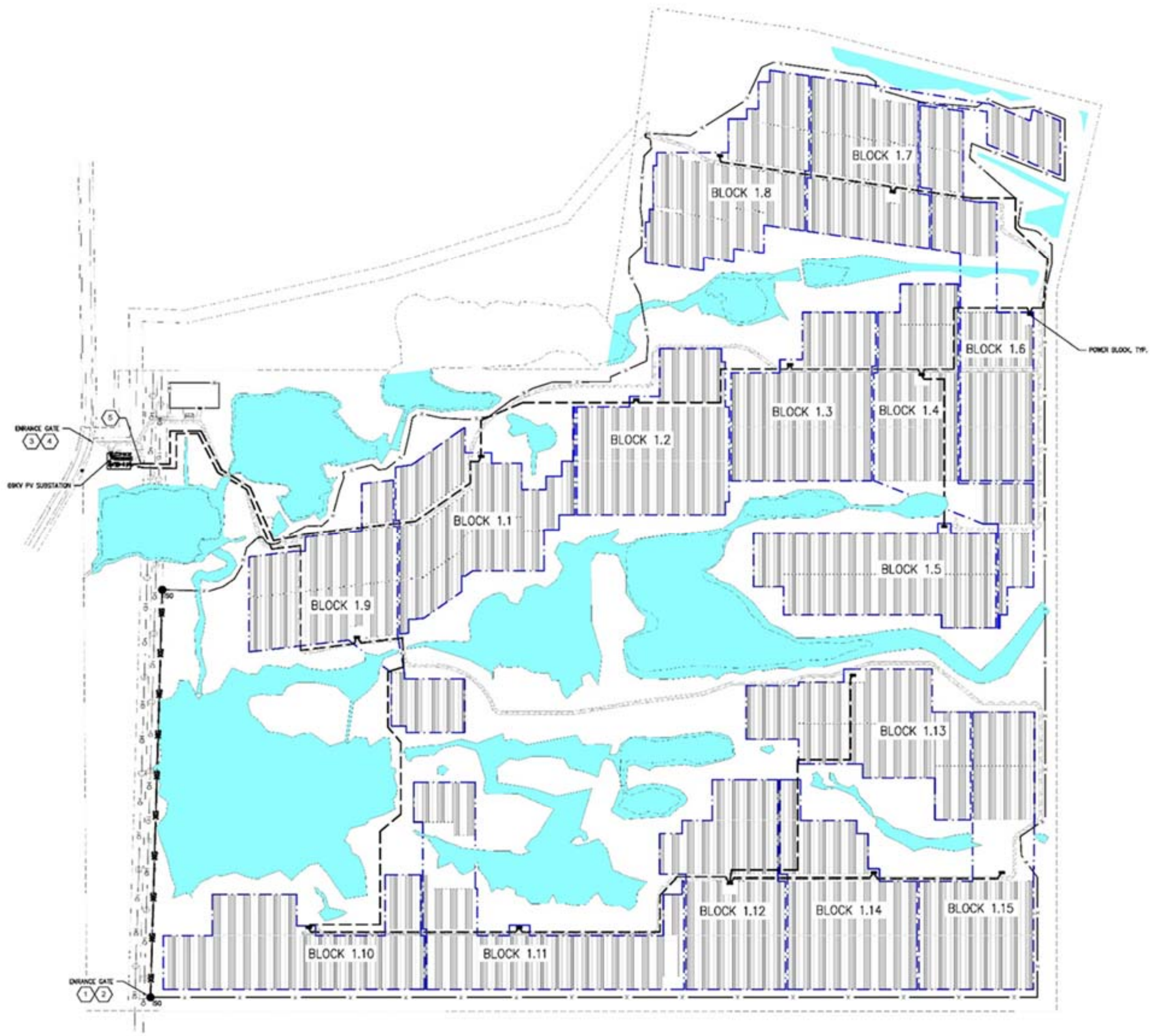
Bonnie Mine Solar Project General Arrangement Drawing



Bonnie Mine Solar Project Projected Installed Cost by Category

Estimated Costs ($MM)	
Project Output (MW-ac)	37.5
Major Equipment[1]	[redacted]
Balance of System[2]	[redacted]
Development	1.4
Transmission Interconnect	0.9
Land	4.3
Owners Costs	0.3
Total Installed Cost ($MM)	54.1
AFUDC ($MM)	0.8
Total All-in-Cost ($MM)	54.9
Total ($/kW-ac)	1,464

[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

Lake Hancock Solar Project Specifications

Specifications of Proposed Solar PV Generating Facilities

(1)	Plant Name and Unit Number	Lake Hancock Solar
(2)	Net Capability	49.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	January 2018
	B. Commercial In-Service Date	January 2019
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+358 Acres
(9)	Construction Status	In Progress
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2018)	26.27% (1st Full Yr Operation)
	Average Net Operating Heat Rate (ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	1,494.23
	Direct Construction Cost ($/kW)	1,494.23
	AFUDC Amount ($/kW) [2]	N/A
	Escalation ($/kW)	N/A
	Fixed O&M ($/kW – yr)	7.70
	Variable O&M ($/MWh)	0.0
	K-Factor [3]	1.12

1 Includes interconnect, AFUDC, land w/o incentive
2 Based on the current AFUDC rate of 6.46%
3 W/o land

Lake Hancock Solar Project General Arrangement Drawing

Lake Hancock Solar Project Projected Installed Cost by Category

Estimated Costs ($MM)	
Project Output (MW-ac)	49.5
Major Equipment[1]	[redacted]
Balance of System[2]	[redacted]
Development	1.6
Transmission Interconnect	4.1
Land	9.1
Owners Costs	0.3
Total Installed Cost ($MM)	74.0
AFUDC ($MM)	-
Total All-in-Cost ($MM)	74.0
Total ($/kW-ac)	1,494

[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

EXHIBIT

OF

R. JAMES ROCHA

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180133-EI EXHIBIT: 3
PARTY: TAMPA ELECTRIC COMPANY–
(DIRECT)
DESCRIPTION: R. James Rocha RJR-1

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Demand & Energy Forecast

	Winter (MW)	Summer (MW)	Energy (GWh)
2018	4,044	4,092	20,588
2019	4,337	4,121	20,445
2020	4,382	4,176	20,602
2021	4,443	4,229	20,830
2022	4,494	4,274	20,989
2023	4,557	4,330	21,246
2024	4,618	4,385	21,504
2025	4,680	4,440	21,775
2026	4,740	4,495	22,041
2027	4,802	4,550	22,323
2028	4,863	4,607	22,622
2029	4,925	4,664	22,924
2030	4,985	4,716	23,193
2031	5,037	4,764	23,449
2032	5,089	4,812	23,706
2033	5,141	4,861	23,965
2034	5,194	4,912	24,231
2035	5,248	4,963	24,506
2036	5,300	5,013	24,787
2037	5,354	5,064	25,076
2038	5,354	5,064	25,076
2039	5,354	5,064	25,076
2040	5,354	5,064	25,076
2041	5,354	5,064	25,076
2042	5,354	5,064	25,076
2043	5,354	5,064	25,076
2044	5,354	5,064	25,076
2045	5,354	5,064	25,076
2046	5,354	5,064	25,076
2047	5,354	5,064	25,076
2048	5,354	5,064	25,076

Fuel Forecast ($/MMBtu)

	Coal	Natural Gas
2018	2.42	3.03
2019	2.43	2.98
2020	2.39	3.05
2021	2.45	3.28
2022	2.48	3.45
2023	2.54	3.52
2024	2.58	3.71
2025	2.70	3.97
2026	2.84	4.26
2027	2.92	4.54
2028	3.01	4.81
2029	3.09	5.07
2030	3.17	5.33
2031	3.27	5.65
2032	3.36	5.94
2033	3.43	6.20
2034	3.49	6.45
2035	3.54	6.68
2036	3.62	7.00
2037	3.69	7.28
2038	3.77	7.64
2039	3.86	8.00
2040	3.93	8.34
2041	3.97	8.59
2042	4.08	8.88
2043	4.19	9.16
2044	4.30	9.47
2045	4.40	9.76
2046	4.52	10.07
2047	4.63	10.39
2048	4.80	10.90

Revenue Requirements for Second SoBRA

260.3 MW of Solar Projects

($000)	2019
Lithia	11,193
Grange Hall	9,114
Peace Creek	8,142
Bonnie Mine	5,809
Lake Hancock	4,781
Capital RR	39,038
Lithia	547
Grange Hall	448
Peace Creek	407
Bonnie Mine	275
Lake Hancock	233
FOM	1,911
Land RR	4,917
TOTAL RR	$45,866

Revenue Requirements for Second SoBRA

With Sharing Mechanism

260.3 MW of Solar Projects
with 75%/25% Incentive

($000)	2019
Lithia	11,205
Grange Hall	9,223
Peace Creek	8,155
Bonnie Mine	5,848
Lake Hancock	4,786
Capital RR	39,218
Lithia	547
Grange Hall	448
Peace Creek	407
Bonnie Mine	275
Lake Hancock	233
FOM	1,911
Land RR	4,917
TOTAL RR	$46,045

COST-EFFECTIVENESS TEST FOR SECOND SoBRA

(Based on the entire 278 MW being constructed)

Delta CPWRR Revenue Requirements - Base Fuel	**Cost/(Savings) (2018 US $ millions)**
Capital RR - Other New Units	($84.1)
Capital RR - Solar New Arrays (w/Interconnect)	$348.9
RR of Land for Solar	$65.7
System VOM	($20.3)
FOM - Other Future Units	$0.0
FOM - Solar Future Arrays	$31.9
System Fuel	($345.7)
System Capacity	($9.1)
Sub Total w/o NOX or CO2 Cost	($12.6)
Plus Emissions Costs	
CO2 - Base	($25.7)
CO2 - High	($92.9)
CO2 - Low	$0.0
NOX - Base	($1.1)
BASE: Total w/ CO2 & NOX Cost	($39.4)
or HIGH: Total w/ CO2 & NOX Cost	($106.5)
or LOW: Total w/ CO2 & NOX Cost	($13.7)

COST-EFFECTIVENESS TEST FOR SECOND SoBRA

(Based on only the 260.3 MW allowed in the Second SoBRA)

	Cost/(Savings) (2018 US $ millions)
Capital RR - Other New Units	($78.8)
Capital RR - Solar New Arrays (w/Interconnect)	$326.7
RR of Land for Solar	$61.2
System VOM	($19.2)
FOM - Other Future Units	$0.0
FOM - Solar Future Arrays	$29.9
System Fuel	($324.9)
System Capacity	($9.1)
Sub Total w/o NOX or CO2 Cost	($14.2)
Plus Emissions Costs	
CO2 - Base	($23.8)
CO2 - High	($86.7)
CO2 - Low	$0.0
NOX - Base	($1.0)
BASE: Total w/ CO2 & NOX Cost	($39.0)
or HIGH: Total w/ CO2 & NOX Cost	($101.9)
or LOW: Total w/ CO2 & NOX Cost	($15.2)

EXHIBIT

OF

WILLIAM R. ASHBURN

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180133-EI EXHIBIT: 4
PARTY: TAMPA ELECTRIC COMPANY–(DIRECT)
DESCRIPTION: William R. Ashburn WRA-1

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Development of

Second SoBRA Base Revenue Increase

by Rate Class

TAMPA ELECTRIC COMPANY
DEVELOPMENT OF SECOND SoBRA BASE REVENUE INCREASE BY RATE CLASS FOR 2019
USING SEPTEMBER 1, 2018 RATES ADJUSTED FOR FIRST SoBRA AND 2018 TAX REFORM
($000)

260 MW Second SoBRA
12CP &1/13 - All Demand

Line		Rate Class	(A) Adjusted Revenue Requirement(1)	(B) Present Base Revenue(2)	(C) Base Revenue Deficiency $ (A) - (B)	(D) Base Revenue Deficiency % (C) / (B)	(E) Proposed Base Rev. Increase $	(F) Proposed Base Rev. Increase % (E) / (B)	(G) 2019 Targeted Base Revenue (B) + (E)
1	I.	Residential (RS,RSVP)	$ 635,982	$ 609,837	$ 26,145	4.29%			
2									
3	II.	General Service							
4		Non-Demand (GS,CS)	66,579	64,307	2,272	3.53%			
5									
6									
7		Sub-Total: I. + II.	$ 702,561	$ 674,144	$ 28,417	4.22%	$ 28,417	4.22%	$ 702,561
8									
9									
10	III.	General Service							
11		Demand (GSD, SBF)	346,172	329,755	16,417	4.98%	$ 16,417	4.98%	346,172
12									
13	IV.	Interruptible Service (IS/SBI)	29,801	28,617	1,184	4.14%	$ 1,184	4.14%	29,801
15									
16									
19	V.	Lighting (LS-1)							
20		A. - Energy	$ 4,388	4,361	27	0.61%	$ 27	0.61%	$ 4,388
21		B. - Facilities	43,545	43,545	-	0.00%	$ -	0.00%	$ 43,545
22									
23									
24		Total	$ 1,126,467	$ 1,080,421	$ 46,045	4.26%	$ 46,045	4.26%	$ 1,126,467
25									
26				$ 46,045					
27									

28 (1) The Adjusted Revenue Requirement column reflects an increase of $46.045 million annual Second SoBRA revenues based on each class' percentage
29 of 12 CP & 1/13th allocator plus an 40% allocation to lighting service of Second SoBRA increase.
30 (2) Present base revenue is calculated using base rates reflect First SoBRA to be in effect first billing cycle of September 2018 and tax reform to be in effect first
31 billing cycle of January 2019, applied to 2019 projected billing determinants.

TAMPA ELECTRIC COMPANY
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REVISED: 07/05/18

2018
12 CP &1/13 Allocation

46045

Lighting allocation spread over other classes

67		0.286%
	60.00%	
40		
	40.00%	
27		

		Lighting Share Reallocation		FINAL RR	Lighting Share Reallocation		FINAL RR
$000	%	$000	%	$000	$000	%	$000
26,122	56.732%	38	56.81%	26,160	23	56.81%	26,145
2,270	4.930%	3	4.94%	2,273	2	4.94%	2,272
	61.662%						
16,403	35.624%	24	35.68%	16,427	14	35.68%	16,417
1,183	2.569%	2	2.57%	1,185	1	2.57%	1,184
67	0.145%						27
46,045	100.0000%	67	100%	46,045	40	100%	46,045

TAMPA ELECTRIC COMPANY
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Base Revenue by Rate Schedule for Second SoBRA

REVISED: 09/24/2018

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

Line No.	Page No.	Rate Schedule
6	2	RS, RSVP-1
7	3	GS, GST
8	4	CS
9	5	GSD, GSDT
10	6	GSD Optional
11	9	SBF, SBFT
12	10	IS, IST
13	14	SBI
14	16	LS-1 (Energy Service)

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule RS, RSVP-1

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1										
2	Basic Service Charge:									
3	Standard	8,124,336	Bills	$ 16.62	135,026,464	8,124,336	Bills	$ 15.12	122,836,987	
4	RSVP-1	54,683	Bills	$ 16.62	908,831	54,683	Bills	$ 15.12	826,787	
5	Total	8,179,019	Bills		135,935,296	8,179,019	Bills		123,663,774	-9.0%
6										
7										
8										
9	Energy Charge:									
10	Standard									
11	First 1,000 kWh	6,383,752	MWH	$ 53.81	343,477,776	6,383,752	MWH	$ 51.41	328,218,056	
12	All additional kWh	2,915,954	MWH	$ 63.81	186,052,445	2,915,954	MWH	$ 61.41	179,082,149	
13	RSVP-1	82,913	MWH	$ 56.95	4,721,481	82,913	MWH	$ 54.55	4,523,286	
14	Total	9,382,619	MWH		534,251,702	9,382,619	MWH		511,823,490	-4.2%
15										
16										
17										
18	Total Base Revenue:				670,186,998				635,487,263	-5.2%
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32										
33										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

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EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule GS, GST

Line No.	Type of Charges	Present Revenue Calculation				Proposed Revenue Calculation				Percent Decrease
		Units		Charge/Unit	$ Revenue	Units		Charge/Unit	$ Revenue	
1										
2	Basic Service Charge:									
3	Standard Metered	766,940	Bills	$ 19.94	15,292,784	766,940	Bills	$ 18.14	13,912,232	
4	Standard Unmetered	1,188	Bills	$ 16.62	19,745	1,188	Bills	$ 15.12	17,962	
5	T-O-D	28,994	Bills	$ 22.16	642,507	28,994	Bills	$ 20.16	584,505	
6	T-O-D (Meter CIAC paid)	24	Bills	$ 19.94	479	24	Bills	$ 18.14	435	
7	Total	797,146	Bills		15,955,514	797,146	Bills		14,515,134	-9.0%
8										
9	Energy Charge:									
10	Standard	910,450	MWH	$ 56.76	51,679,418	910,450	MWH	$ 54.12	49,272,279	
11	Standard Unmetered	1,295	MWH	$ 56.76	73,507	1,295	MWH	$ 54.12	70,084	
12	T-O-D On-Peak	8,582	MWH	$ 144.88	1,243,360	8,582	MWH	$ 149.63	1,284,125	
13	T-O-D Off-Peak	24,929	MWH	$ 15.45	385,153	24,929	MWH	$ 21.08	525,575	
14	Total	945,256	MWH		53,381,439	945,256	MWH		51,152,063	-4.2%
15										
16	Emergency Relay Charge:									
17	Standard	2,041	MWH	$ 1.71	3,498	2,041	MWH	$ 1.64	3,351	
18	T-O-D	-	MWH	$ 1.71	-	-	MWH	$ 1.64	-	
19	Total	2,041	MWH		3,498	2,041	MWH		3,351	-4.2%
20										
21										
22										
23	Total Base Revenue:				69,340,450				65,670,548	-5.3%
24										
25										
26										
27										
28										
29										
30										
31										
32										
33										
34										
35										

Supporting Schedules:

Recap Schedules: E-13a

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SCHEDULE E-13c	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS	Page 4 of 17

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Rate Schedule CS

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1										
2	Basic Service Charge:									
3		36,639	Bills	$ 19.94	730,582	36,639	Bills	$ 18.14	664,629	
4	Total	36,639	Bills		730,582	36,639	Bills		664,629	-9.0%
5										
6	Energy Charge:									
7		10,575	MWH	$ 56.76	600,263	10,575	MWH	$ 54.12	572,304	
8	Total	10,575	MWH		600,263	10,575	MWH		572,304	-4.7%
9										
10										
11										
12	Total Base Revenue:				1,330,845				1,236,933	-7.1%
13										
14										
15										
16										
17										
18										
19										
20										
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32										
33										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Rate Schedule GSD, GSDT

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1	Basic Service Charge:									
2	Standard - Secondary	157,303	Bills	$ 33.24	5,228,752	157,303	Bills	$ 30.24	4,756,728	
3	Standard - Primary	812	Bills	$ 144.03	116,890	812	Bills	$ 131.03	106,338	
4	Standard - Subtransmission	-	Bills	$ 1,096.82	-	0	Bills	$ 997.80	-	
5	T-O-D - Secondary	14,214	Bills	$ 33.24	472,473	14,214	Bills	$ 30.24	429,821	
6	T-O-D - Primary	766	Bills	$ 144.03	110,327	766	Bills	$ 131.03	100,367	
7	T-O-D - Subtransmission	25	Bills	$ 1,096.82	27,421	25	Bills	$ 997.80	24,945	
8	Total	173,120	Bills		5,955,863	173,120			5,418,199	-9.0%
9										
10	Energy Charge:									
11	Standard - Secondary	4,327,159	MWH	$ 17.54	75,898,369	4,327,159	MWH	$ 15.96	69,046,664	
12	Standard - Primary	298,377	MWH	$ 17.54	5,233,533	298,377	MWH	$ 15.96	4,761,077	
13	Standard - Subtransmission	-	MWH	$ 17.54	-	-	MWH	$ 15.96	-	
14	T-O-D On-Peak - Secondary	537,358	MWH	$ 32.11	17,254,565	537,358	MWH	$ 29.21	15,696,914	
15	T-O-D On-Peak - Primary	264,905	MWH	$ 32.11	8,506,100	264,905	MWH	$ 29.21	7,738,214	
16	T-O-D On-Peak - Subtrans.	518	MWH	$ 32.11	16,633	518	MWH	$ 29.21	15,131	
17	T-O-D Off-Peak - Secondary	1,479,672	MWH	$ 11.59	17,149,398	1,479,672	MWH	$ 10.54	15,601,241	
18	T-O-D Off-Peak - Primary	730,501	MWH	$ 11.59	8,466,507	730,501	MWH	$ 10.54	7,702,195	
19	T-O-D Off-Peak - Subtrans.	1,521	MWH	$ 11.59	17,628	1,521	MWH	$ 10.54	16,037	
20	Total	7,640,011	MWH		132,542,733	7,640,011	MWH		120,577,473	-9.0%
21										
22	Demand Charge:									
23	Standard - Secondary	11,357,612	kW	$ 10.70	121,526,448	11,357,612	kW	$ 10.59	120,277,111	
24	Standard - Primary	750,006	kW	$ 10.70	8,025,064	750,006	kW	$ 10.59	7,942,564	
25	Standard - Subtransmission	-	kW	$ 10.70	-	-	kW	$ 10.59	-	
26	T-O-D Billing - Secondary	3,803,267	kW	$ 3.61	13,729,794	3,803,267	kW	$ 3.57	13,577,663	
27	T-O-D Billing - Primary	1,901,141	kW	$ 3.61	6,863,119	1,901,141	kW	$ 3.57	6,787,073	
28	T-O-D Billing - Subtrans.	5,568	kW	$ 3.61	20,100	5,568	kW	$ 3.57	19,878	
29	T-O-D Peak - Secondary	3,672,362	kW (1)	$ 7.09	26,037,047	3,672,362	kW (1)	$ 7.02	25,779,981	
30	T-O-D Peak - Primary	1,824,974	kW (1)	$ 7.09	12,939,066	1,824,974	kW (1)	$ 7.02	12,811,317	
31	T-O-D Peak - Subtrans.	4,905	kW (1)	$ 7.09	34,776	4,905	kW (1)	$ 7.02	34,433	
32	Total	17,817,594	kW		189,175,415	17,817,594	kW		187,230,021	-1.0%
33										
34	(1) Not included in Total.									
35										

Continued on Page 6

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule GSD, GSDT

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1	Continued from Page 8									
2										
3	Delivery Voltage Credit:									
4	Standard Primary	663,959	kW	$ (0.87)	(577,644)	663,959	kW	$ (0.86)	(571,005)	
5	Standard - Subtransmission	-	kW	$ (2.69)	-	-	kW	$ (2.66)	-	
6	T-O-D Primary	1,539,592	kW	$ (0.87)	(1,339,445)	1,539,592	kW	$ (0.86)	(1,324,049)	
7	T-O-D Subtransmission	8,490	kW	$ (2.69)	(22,838)	8,490	kW	$ (2.66)	(22,583)	
8	Total	2,212,041	kW		(1,939,927)	2,212,041	kW		(1,917,637)	-1.1%
9										
10	Emergency Relay Charge:									
11	Standard Secondary	437,907	kW	$ 0.69	302,156	437,907	kW	$ 0.68	297,777	
12	Standard Primary	166,511	kW	$ 0.69	114,893	166,511	kW	$ 0.68	113,227	
13	Standard - Subtransmission	-	kW	$ 0.69	-	-	kW	$ 0.68	-	
14	T-O-D Secondary	749,073	kW	$ 0.69	516,860	749,073	kW	$ 0.68	509,370	
15	T-O-D Primary	771,690	kW	$ 0.69	532,466	771,690	kW	$ 0.68	524,749	
16	T-O-D Subtransmission	-	kW	$ 0.69	-	-	kW	$ 0.68	-	
17	Total	2,125,181	kW		1,466,375	2,125,181	kW		1,445,123	-1.4%
18										
19	Power Factor Charge:									
20	Standard Secondary	12,038	MVARh	$ 2.22	26,724	12,038	MVARh	$ 2.02	24,318	
21	Standard Primary	12,054	MVARh	$ 2.22	26,760	12,054	MVARh	$ 2.02	24,350	
22	Standard - Subtransmission	0	MVARh	$ 2.22	-	0	MVARh	$ 2.02	-	
23	T-O-D Secondary	12,613	MVARh	$ 2.22	28,001	12,613	MVARh	$ 2.02	25,479	
24	T-O-D Primary	10,522	MVARh	$ 2.22	23,359	10,522	MVARh	$ 2.02	21,255	
25	T-O-D Subtransmission	142	MVARh	$ 2.22	315	142	MVARh	$ 2.02	287	
26		47,369	MVARh		105,159	47,369	MVARh		95,690	-9.0%
27										
28										
29										
30										
31										
32										
33										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Rate Schedule GSD, GSDT

Line No.	Type of Charges	Present Revenue Calculation Units	Present Charge/Unit	Present $ Revenue	Proposed Revenue Calculation Units	Proposed Charge/Unit	Proposed $ Revenue	Percent Decrease
1	Continued from Page 9							
2								
3	Power Factor Credit:							
4	Standard Secondary	28844 MVARh	$ (1.11)	(32,017)	28844 MVARh	$ (1.01)	(29,134)	
5	Standard Primary	16646 MVARh	$ (1.11)	(18,477)	16646 MVARh	$ (1.01)	(16,813)	
6	Standard - Subtransmission	0 MVARh	$ (1.11)	-	0 MVARh	$ (1.01)	-	
7	T-O-D Secondary	108106 MVARh	$ (1.11)	(119,998)	108106 MVARh	$ (1.01)	(109,192)	
8	T-O-D Primary	59840 MVARh	$ (1.11)	(66,422)	59840 MVARh	$ (1.01)	(60,441)	
9	T-O-D Subtransmission	0 MVARh	$ (1.11)	-	0 MVARh	$ (1.01)	-	
10		213,436 MVARh		(236,914)	213,436 MVARh		(215,580)	-9.0%
11								
12								
13	Metering Voltage Adjustment:							
14	Standard Primary	12,804,128 $	-1%	(128,041)	12,253,400 $	-1%	(122,534)	
15	Standard - Subtransmission	- $	-2%	-	- $	-2%	-	
16	T-O-D Primary	35,924,748 $	-1%	(359,247)	34,200,314 $	-1%	(342,003)	
17	T-O-D Subtransmission	66,615 $	-2%	(1,332)	63,183 $	-2%	(1,264)	
18	Total	48,795,492 $		(488,621)	46,516,897 $		(465,801)	-4.7%
19								
20								
21								
22								
23	Total Base Revenue:			326,580,082			312,167,488	-4.4%
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Rate Schedule GSD Optional

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1	Basic Service Charge:									
2	Optional - Secondary	19,672	Bills	$ 33.24	653,897	19,672	Bills	$ 30.24	594,867	
3	Optional - Primary	307	Bills	$ 144.03	44,217	307	Bills	$ 131.03	40,226	
4	Optional - Subtransmission	-		$ 1,096.82	-	-		$ 997.80	-	
5	Total	19,979	Bills		698,114	19,979	Bills		635,092	-9.0%
6										
7	Energy Charge:									
8	Optional - Secondary	388,398	MWH	$ 68.12	26,457,672	388,398	MWH	$ 64.94	25,222,566	
9	Optional - Primary	12,811	MWH	$ 68.12	872,685	12,811	MWH	$ 64.94	831,946	
10	Total	401,209	MWH		27,330,357	401,209	MWH		26,054,512	-4.7%
11										
12	Demand Charge:									
13	Optional - Secondary	2,406,400	kW	$ -	-	2,406,400	kW	$ -	-	
14	Optional - Primary	97,955	kW	$ -	-	97,955	kW	$ -	-	
15	Total	2,504,355	kW		-	2,504,355			-	0.0%
16										
17	Delivery Voltage Credit:									
18	Optional - Primary	6,070	MWH	$ (2.30)	(13,961)	6,070	MWH	$ (2.28)	(13,840)	
19	Optional - Subtransmission	-	MWH	$ (7.02)	-	-	MWH	$ (6.95)	-	
20	Total	6,070	MWH		(13,961)	6,070	MWH		(13,840)	-0.9%
21										
22	Emergency Relay									
23	Optional - Secondary	11,959	MWH	$ 1.74	20,809	11,959	MWH	$ 1.72	20,569	
24	Optional - Primary	1,633	MWH	$ 1.74	2,841	1,633	MWH	$ 1.72	2,809	
25	Total	13,592	MWH		23,650	13,592	MWH		23,378	-1.1%
26										
27	Metering Voltage Adjustment:									
28	Optional - Primary	861,566	$	-1%	(8,616)	820,916	$	-1%	(8,209)	
29	Optional - Subtransmission	-	$	-2%	-	-	$	-2%	-	
30	Total	861,566	$		(8,616)	820,916	$		(8,209)	-4.7%
31										
32										
33										
34	Total Base Revenue:				28,029,545				26,690,934	-4.8%
35										

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule SBF, SBFT

Line No.	Type of Charges	Present Revenue Calculation: Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation: Units		Charge/Unit	$ Revenue	Percent Decrease
1										
2	Basic Service Charge:									
3	Standard Secondary	0	Bills	$ 60.93	-	0	Bills	$ 55.43	-	
4	Standard Primary	0	Bills	$ 171.72	-	0	Bills	$ 156.22	-	
5	Standard Subtransmission	0	Bills	$ 1,124.52	-	0	Bills	$ 1,023.00	-	
6	T-O-D Secondary	0	Bills	$ 60.93	-	0	Bills	$ 55.43	-	
7	T-O-D Primary	37	Bills	$ 171.72	6,354	37	Bills	$ 156.22	5,780	
8	T-O-D Subtransmission	50	Bills	$ 1,124.52	56,226	50	Bills	$ 1,023.00	51,150	
9	Total	87	Bills		62,580	87	Bills		56,930	-9.0%
10										
11	Energy Charge - Supplemental:									
12	Standard Secondary	0	MWH	$ 17.54	-	-	MWH	$ 15.96	-	
13	Standard Primary	0	MWH	$ 17.54	-	-	MWH	$ 15.96	-	
14	Standard Subtransmission	0	MWH	$ 17.54	-	-	MWH	$ 15.96	-	
15	T-O-D On-Peak - Secondary	0	MWH	$ 32.11	-	-	MWH	$ 29.21	-	
16	T-O-D On-Peak - Primary	28,197	MWH	$ 32.11	905,406	28,197	MWH	$ 29.21	823,670	
17	T-O-D On-Peak - Subtrans.	-	MWH	$ 32.11	-	-	MWH	$ 29.21	-	
18	T-O-D Off-Peak - Secondary	0	MWH	$ 11.59	-	-	MWH	$ 10.54	-	
19	T-O-D Off-Peak - Primary	84,550	MWH	$ 11.59	979,935	84,550	MWH	$ 10.54	891,471	
20	T-O-D Off-Peak - Subtrans.	-	MWH	$ 11.59	-	-	MWH	$ 10.54	-	
21	Energy Charge - Standby:									
22	T-O-D On-Peak -Secondary	-	MWH	$ 10.12	-	-	MWH	$ 9.21	-	
23	T-O-D On-Peak - Primary	2,133	MWH	$ 10.12	21,586	2,133	MWH	$ 9.21	19,637	
24	T-O-D On-Peak - Subtrans.	2,001	MWH	$ 10.12	20,250	2,001	MWH	$ 9.21	18,422	
25	T-O-D Off-Peak -Secondary	-	MWH	$ 10.12	-	-	MWH	$ 9.21	-	
26	T-O-D Off-Peak - Primary	6,304	MWH	$ 10.12	63,796	6,304	MWH	$ 9.21	58,037	
27	T-O-D Off-Peak - Subtrans.	5,914	MWH	$ 10.12	59,850	5,914	MWH	$ 9.21	54,447	
28	Total	129,099	MWH		2,050,822	129,099	MWH		1,865,685	-9.0%
29										
30										
31										
32										
33										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Rate Schedule SBF, SBFT

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1	Continued from Page 13									
2										
3	Demand Charge - Supplemental:									
4	Standard Secondary	-	kW	$ 10.70	-	-	kW	$ 10.59	-	
5	Standard Primary	-	kW	$ 10.70	-	-	kW	$ 10.59	-	
6	Standard Subtransmission	-	kW	$ 10.70	-	-	kW	$ 10.59	-	
7	T-O-D Billing - Secondary	-	kW	$ 3.61	-	-	kW	$ 3.57	-	
8	T-O-D Billing - Primary	187,866	kW	$ 3.61	678,196	187,866	kW	$ 3.57	670,682	
9	T-O-D billing - Subtransmission	-	kW	$ 3.61	-	-	kW	$ 3.57	-	
10	T-O-D Peak - Secondary	-	kW (1)	$ 7.09	-	-	kW (1)	$ 7.02	-	
11	T-O-D Peak - Primary	181,526	kW (1)	$ 7.09	1,287,019	181,526	kW (1)	$ 7.02	1,274,313	
12	T-O-D Peak - Subtransmission	-	kW (1)	$ 7.09	-	-	kW (1)	$ 7.02	-	
13	Demand Charge - Standby:									
14	T-O-D Facilities Reservation - Sec.	-	kW	$ 2.15	-	-	kW	$ 1.96	-	
15	T-O-D Facilities Reservation - Pri.	111,712	kW	$ 2.15	240,181	111,712	kW	$ 1.96	218,956	
16	T-O-D Facilities Reservation - Sub.	239,672	kW	$ 2.15	515,295	239,672	kW	$ 1.96	469,757	
17	T-O-D Power Supply Res. - Sec.	-	kW (1)	$ 1.71 / kW-mo.	-	-	kW (1)	$ 1.56 kW-mo.	-	
18	T-O-D Power Supply Res. - Pri.	55,882	kW (1)	$ 1.71 / kW-mo.	95,558	55,882	kW (1)	$ 1.56 kW-mo.	87,176	
19	T-O-D Power Supply Res. - Sub.	181,235	kW (1)	$ 1.71 / kW-mo.	309,912	181,235	kW (1)	$ 1.56 kW-mo.	282,727	
20	T-O-D Power Supply Dmd. - Sec.	-	kW (1)	$ 0.68 / kW-day	-	-	kW (1)	$ 0.62 kW-day	-	
21	T-O-D Power Supply Dmd. - Pri.	340,955	kW (1)	$ 0.68 / kW-day	231,849	340,955	kW (1)	$ 0.62 kW-day	211,392	
22	T-O-D Power Supply Dmd. - Sub.	265,610	kW (1)	$ 0.68 / kW-day	180,615	265,610	kW (1)	$ 0.62 kW-day	164,678	
23	Total	539,250	kW		3,538,625	539,250	kW		3,379,680	-4.5%
24										
25										
26	Power Factor Charge Supplemental & Standby:									
27	Standard Secondary	-	MVARh	$ 2.22	-	-	MVARh	$ 2.02	-	
28	Standard Primary	-	MVARh	$ 2.22	-	-	MVARh	$ 2.02	-	
29	Standard Subtransmission	-	MVARh	$ 2.22	-	-	MVARh	$ 2.02	-	
30	T-O-D Secondary	-	MVARh	$ 2.22	-	-	MVARh	$ 2.02	-	
31	T-O-D Primary	5,575	MVARh	$ 2.22	12,377	5,575	MVARh	$ 2.02	11,262	
32	T-O-D Subtransmission	1,114	MVARh	$ 2.22	2,473	1,114	MVARh	$ 2.02	2,250	
33		6,689			14,850	6,689			13,512	-9.0%
34	(1) Not included in Total.									
35										Continued on Page 11

Supporting Schedules: Recap Schedules: E-13a

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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Rate Schedule SBF, SBFT

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1	Continued from Page 14									
2										
3	Power Factor Credit Supplemental & Standby:									
4	Standard Secondary	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.01)	-	
5	Standard Primary	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.01)	-	
6	Standard Subtransmission	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.01)	-	
7	T-O-D Secondary	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.01)	-	
8	T-O-D Primary	6,826	MVARh	$ (1.11)	(7,577)	6,826	MVARh	$ (1.01)	(6,895)	
9	T-O-D Subtransmission	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.01)	-	
14	Total	6,826	MVARh		(7,577)	6,826	MVARh		(6,895)	-9.0%
15										
16	Delivery Voltage Credit - Supplemental.:									
17	Standard Primary	-	kW	$ (0.87)	-	-	kW	$ (0.86)	-	
18	Standard Subtransmission	-	kW	$ (2.69)	-	-	kW	$ (2.66)	-	
19	T-O-D Primary	187,866	kW	$ (0.87)	(163,443)	187,866	kW	$ (0.86)	(161,565)	
20	T-O-D Subtransmission	-	kW	$ (2.69)	-	-	kW	$ (2.66)	-	
21	Delivery Voltage Credit. - Standby.:									
22	T-O-D Primary	111,712	kW	$ (0.69)	(77,081)	111,712	kW	$ (0.63)	(70,140)	
23	T-O-D Subtransmission	239,672	kW	$ (2.16)	(517,692)	239,672	kW	$ (1.97)	(471,073)	
24	Total	539,250	kW		(758,216)	539,250	kW		(702,778)	-7.3%
25										
26	Emergency Relay Charge - Supplemental and Standby.									
27	Standard Secondary	-	kW	$ 0.69	-	-	kW	$ 0.68	-	
28	Standard Primary	-	kW	$ 0.69	-	-	kW	$ 0.68	-	
29	Standard Subtransmission	-	kW	$ 0.69	-	-	kW	$ 0.68	-	
30	T-O-D Secondary	-	kW	$ 0.69	-	-	kW	$ 0.68	-	
31	T-O-D Primary	177,812	kW	$ 0.69	122,690	177,812	kW	$ 0.68	120,912	
32	T-O-D Subtransmission	-	kW	$ 0.69	-	-	kW	$ 0.68	-	
33		177,812			122,690	177,812			120,912	-1.4%
34										
35										
36										
37										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule SBF, SBFT

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1	Continued from Page 15									
2										
3	Metering Voltage Adjustment - Supplemental and Stanby.:									
4	Standard Primary	-	$	-1.0%	-	-	$	-1.0%	-	
5	Standard Subtransmission	-	$	-2.0%	-	-	$	-2.0%	-	
6	T-O-D Primary	4,390,492	$	-1.0%	(43,905)	4,148,909	$	-1.0%	(41,489)	
7	T-O-D Subtransmission	570,703	$	-2.0%	(11,414)	521,208	$	-2.0%	(10,424)	
8	Total	4,961,195	$		(55,319)	4,670,116	$		(51,913)	-6.2%
9										
10										
11										
12	Total Base Revenue:				4,968,455				4,675,133	-5.9%
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32										
33										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Rate Schedule IS, IST

Line No.	Type of Charges	Present Units		Present Charge/Unit	Present $ Revenue	Proposed Units		Proposed Charge/Unit	Proposed $ Revenue	Percent Increase/Decrease
1										
2	Basic Service Charge:									
3	Standard Pri.	74	Bills	$ 689.11	50,994	74	Bills	$ 626.90	46,391	
4	Standard Subtrans.	-	Bills	$ 2,627.94	-	-	Bills	$ 2,390.70	-	
5	T-O-D Primary	113	Bills	$ 689.11	77,821	113	Bills	$ 626.90	70,796	
6	T-O-D Subtransmission	100	Bills	$ 2,627.94	263,793	100	Bills	$ 2,390.70	239,979	
7	Total	287	Bills		392,608	287	Bills		357,165	-9.0%
8										
9	Energy Charge:									
10	Standard Primary	40,657	MWH	$ 27.74	1,127,825	40,657	MWH	$ 25.24	1,026,011	
11	Standard Subtransmission	-	MWH	$ 27.74	-	-	MWH	$ 25.24	-	
12	T-O-D On-Peak - Pri.	31,603	MWH	$ 27.74	876,667	31,603	MWH	$ 25.24	797,526	
13	T-O-D On-Peak - Subtrans.	83,117	MWH	$ 27.74	2,305,666	83,117	MWH	$ 25.24	2,097,522	
14	T-O-D Off-Peak - Pri.	84,068	MWH	$ 27.74	2,332,046	84,068	MWH	$ 25.24	2,121,521	
15	T-O-D Off-Peak - Subtrans.	262,242	MWH	$ 27.74	7,274,593	262,242	MWH	$ 25.24	6,617,881	
16	Total	501,687	MWH		13,916,797	501,687	MWH		12,660,462	-9.0%
17										
18	Demand Charge:									
19	Standard Primary	100,581	kW	$ 2.19	220,272	100,581	kW	$ 3.11	312,807	
20	Standard Subtrans.	-	kW	$ 2.19	-	-	kW	$ 3.11	-	
21	T-O-D Billing - Primary	224,684	kW	$ 2.19	492,058	224,684	kW	$ 3.11	698,767	
22	T-O-D Billing - Subtrans.	933,861	kW	$ 2.19	2,045,156	933,861	kW	$ 3.11	2,904,308	
23	T-O-D Peak - Primary	-	kW (1)	$ -	-	-	kW (1)	$ -	-	
24	T-O-D Peak - Subtrans.	-	kW (1)	$ -	-	-	kW (1)	$ -	-	
25	Total	1,259,126	kW		2,757,486	1,259,126	kW		3,915,882	42.0%
26										
27	Power Factor Charge:									
28	Standard Primary	6,653	MVARh	$ 2.22	14,770	6,653	MVARh	$ 2.02	13,440	
29	Standard Subtrans.	-	MVARh	$ 2.22	-	-	MVARh	$ 2.02	-	
30	T-O-D Primary	12,242	MVARh	$ 2.22	27,177	12,242	MVARh	$ 2.02	24,730	
31	T-O-D Subtransmission	15,573	MVARh	$ 2.22	34,572	15,573	MVARh	$ 2.02	31,459	
32	Total	34,468	MVARh		76,519	34,468	MVARh		69,628	-9.0%
33										
34	(1) Not included in Total.									
35										

Continued on Page 14

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Rate Schedule IS, IST

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase/Decrease
1	Continued from Page 17											
2												
3	Power Factor Credit:											
4	Standard Primary	3,228	MVARh	$	(1.11)	(3,583)	3,228	MVARh	$	(1.01)	(3,260)	
5	Standard Subtrans.	-	MVARh	$	(1.11)	-	-	MVARh	$	(1.01)	-	
6	T-O-D Primary	3,542	MVARh	$	(1.11)	(3,932)	3,542	MVARh	$	(1.01)	(3,578)	
7	T-O-D Subtransmission	-	MVARh	$	(1.11)	-	-	MVARh	$	(1.01)	-	
8	Total	6,770	MVARh			(7,515)	6,770	MVARh			(6,838)	-9.0%
9												
10	Emergency Relay Service											
11	Standard Primary	-	kW	$	0.86	-	-	kW	$	1.22	-	
12	Standard Subtrans.	-	kW	$	0.86	-	-	kW	$	1.22	-	
13	T-O-D Primary	-	kW	$	0.86	-	-	kW	$	1.22	-	
14	T-O-D Subtransmission	-	kW	$	0.86	-	-	kW	$	1.22	-	
15	Total	-	kW			-	-	kW			-	0.0%
16												
17	Delivery Voltage Credit:											
18	Standard Primary	100,581	kW	$	-	-	100,581	kW	$	-	-	
19	Standard Subtrans.	-	kW	$	(0.60)	-	-	kW	$	(0.85)	-	
20	T-O-D Primary	223,155	kW	$	-	-	223,155	kW	$	-	-	
21	T-O-D Subtransmission	935,390	kW	$	(0.60)	(561,234)	935,390	kW	$	(0.85)	(795,082)	
22	Total	1,259,126	kW			(561,234)	1,259,126	kW			(795,082)	41.7%
23												
24	Metering Voltage Adjustment:											
25	Standard Primary	1,359,284	$		0%	-	1,348,997	$		0%	-	
26	Standard Subtrans.	-	$		-1%	-	-	$		-1%	-	
27	T-O-D Primary	3,724,017	$		0%	-	3,638,967	$		0%	-	
28	T-O-D Subtransmission	11,098,752	$		-1%	(110,988)	10,856,088	$		-1%	(108,561)	
29	Total	16,182,054	$			(110,988)	15,844,053	$			(108,561)	-2.2%
30												
31												
32												
33	Total Base Revenue:					16,463,674					16,092,658	-2.3%
34												
35												

Supporting Schedules:

Recap Schedules: E-13a

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REVISED: 09/24/2018

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Rate Schedule SBI

Line No.	Type of Charges	Present Units		Present Charge/Unit		Present $ Revenue	Proposed Units		Proposed Charge/Unit		Proposed $ Revenue	Percent Decrease
1												
2	Basic Service Charge:											
3	T-O-D Primary	0	Bills	$ 717		-	0	Bills	$ 652.10		-	
4	T-O-D Subtransmission	66	Bills	$ 2,656		175,272	66	Bills	$ 2,415.90		159,450	
5	Total	66	Bills			175,272	66	Bills			159,450	-9.0%
6												
7	Energy Charge - Supplemental:											
8	T-O-D On-Peak - Pri.	-	MWH	$ 27.74		-	-	MWH	$ 25.24		-	
9	T-O-D On-Peak - Subtrans.	12,109	MWH	$ 27.74		335,904	12,109	MWH	$ 25.24		305,580	
10	T-O-D Off-Peak - Pri.	-	MWH	$ 27.74		-	-	MWH	$ 25.24		-	
11	T-O-D Off-Peak - Subtrans.	40,470	MWH	$ 27.74		1,122,638	40,470	MWH	$ 25.24		1,021,292	
12	Energy Charge - Standby:											
13	T-O-D On-Peak - Pri.	-	MWH	$ 11.15		-	-	MWH	$ 10.14		-	
14	T-O-D On-Peak - Subtrans.	62,784	MWH	$ 11.15		700,042	62,784	MWH	$ 10.14		636,846	
15	T-O-D Off-Peak - Pri.	-	MWH	$ 11.15		-	-	MWH	$ 10.14		-	
16	T-O-D Off-Peak - Subtrans.	183,017	MWH	$ 11.15		2,040,640	183,017	MWH	$ 10.14		1,856,421	
17	Total	298,380	MWH			4,199,223	298,380	MWH			3,820,139	-9.0%
18												
19	Demand Charge - Supplemental:											
20	T-O-D Billing - Primary	-	kW	$ 2.19	kW	-	-	kW	$ 3.11	kW	-	
21	T-O-D Billing - Subtrans.	134,292	kW	$ 2.19	kW	294,099	134,292	kW	$ 3.11	kW	417,648	
22	T-O-D Peak - Primary	-	kW (1)	$ -	kW	-	-	kW (1)	$ -	kW	-	
23	T-O-D Peak - Subtrans.	-	kW (1)	$ -	kW	-	-	kW (1)	$ -	kW	-	
24	Demand Charge - Standby:											
25	T-O-D Facilities Reservation - Pri.	-	kW	$ 1.61	kW	-	-	kW	$ 1.46	kW	-	
26	T-O-D Facilities Res. - Subtrans.	2,400,000	kW	$ 1.61	kW	3,864,000	2,400,000	kW	$ 1.46	kW	3,504,000	
27	T-O-D Bulk Trans. Res. - Pri.	-	kW (1)	$ 1.33	kW-mo.	-	-	kW (1)	$ 1.21	kW-mo.	-	
28	T-O-D Bulk Trans. Res. - Subtrans.	280,026	kW (1)	$ 1.33	kW-mo.	372,435	280,026	kW (1)	$ 1.21	kW-mo.	338,831	
29	T-O-D Bulk Trans. Dmd. - Pri.	-	kW (1)	$ 0.53	kW-day	-	-	kW (1)	$ 0.48	kW-day	-	
30	T-O-D Bulk Trans Dmd. - Subtrans.	13,285,009	kW (1)	$ 0.53	kW-day	7,041,055	13,285,009	kW (1)	$ 0.48	kW-day	6,376,804	
31	Total	2,534,292	kW			11,571,589	2,534,292	kW			10,637,284	-8.1%
32												
33												
34	(1) Not included in Total.											
35												

Continued on Page 16

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Rate Schedule SBI

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1	Continued from Page 19									
2										
3	Power Factor Charge Supplemental & Standby:									
4	T-O-D Primary	-	MVARh	$ 2.22	-	-	MVARh	$ 2.02	-	
5	T-O-D Subtransmission	84,156	MVARh	$ 2.22	186,826	84,156	MVARh	$ 2.02	170,003	
6	Total	84,156	MVARh		186,826	84,156	MVARh		170,003	-9.0%
7										
8	Power Factor Credit Supplemental & Standby:									
9	T-O-D Primary	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.01)	-	
10	T-O-D Subtransmission	26,619	MVARh	$ (1.11)	(29,547)	26,619	MVARh	$ (1.01)	(26,886)	
11	Total	26,619	MVARh		(29,547)	26,619	MVARh		(26,886)	-9.0%
12										
13	Emergency Relay Charge - Supp.									
14	T-O-D Primary	-	kW	$ 0.86	-	-	kW	$ 1.22	-	
15	T-O-D Subtransmission	-	kW	$ 0.86	-	-	kW	$ 1.22	-	
16	Total	-	kW		-	-	kW		-	0.0%
17										
18	Delivery Voltage Credit - Supplemental.:									
19	T-O-D Primary	-	kW	$ -	-	-	kW	$ -	-	
20	T-O-D Subtransmission	134,292	kW	$ (0.60)	(80,575)	134,292	kW	$ (0.85)	(114,148)	
21	Delivery Voltage Credit. - Standby.:									
22	T-O-D Primary	-	kW	$ -	-	-	kW	$ -	-	
23	T-O-D Subtransmission	2,400,000	kW	$ (0.37)	(888,000)	2,400,000	kW	$ (0.34)	(808,036)	
24	Total	2,534,292	kW		(968,575)	2,534,292	kW		(922,184)	-4.8%
25										
26	Metering Voltage Adjustment - Supplemental and Stanby.:									
27	T-O-D Primary	-	$	0.0%	-	-	$	0.0%	-	
28	T-O-D Subtransmission	14,959,515	$	-1.0%	(149,595)	13,678,355	$	-1.0%	(136,784)	
29	Total	14,959,515	$		(149,595)	13,678,355	$		(136,784)	-8.6%
30										
31										
32										
33	Total Base Revenue:				14,985,193				13,701,021	-8.6%
34										
35										

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule LS-1 (Energy Service)

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Decrease
1												
2	Basic Service Charge:	2,937	Bills	$	11.62	34,128	2,937	Bills	$	10.57	31,047	-9.0%
3												
4	Energy Charge	173,595	MWH	$	27.41	4,758,239	173,595	MWH	$	25.09	4,355,499	-8.5%
5												
6												
7	Total Base Revenue:					4,792,367					4,386,546	-8.5%
8												
9												
10												
11												
12												
13												
14												
15												
16												
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33												
34												
35												

Supporting Schedules: E-13d

Recap Schedules: E-13a

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Rollup Base Revenue by Rate Class for Second SoBRA

REVISED – 09/24/2018

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: Compare jurisdictional revenue excluding service charges by rate schedule under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, the revenue and billing determinant information shall be shown separately for the transfer group and not be included under either the new or old classification.

Type of data shown:
XX Projected Year Ended 12/31/2019

($000)

12CP & 1/13 - all demand

Line No.	Rate	(1) Base Revenue at Present Rates	(2) Base Revenue Under Proposed Rates	Decrease (3) Dollars (2) - (1)	Decrease (4) Percent (3) / (1)
1	RS, RSVP-1	670,187	635,487	(34,700)	-5.2%
2	GS, GST	69,340	65,671	(3,670)	-5.3%
3	CS	1,331	1,237	(94)	-7.1%
4	GSD, GSDT	326,580	312,167	(14,413)	-4.4%
5	GSD Optional	28,030	26,691	(1,339)	-4.8%
6	SBF, SBFT	4,968	4,675	(293)	-5.9%
7	IS, IST	16,464	16,093	(371)	-2.3%
8	SBI	14,985	13,701	(1,284)	-8.6%
9	LS-1 (Energy Service)	4,792	4,387	(406)	-8.5%
10	LS-1 (Facilities)	43,545	43,545	-	0.0%
11					
12					
13	TOTAL	$ 1,180,223	$ 1,123,654	$ (56,569)	-4.8%
14					
15					
16					
17					
18					
19					
20					
21					
22	Summary by Rate Class				
23	RS	670,187	635,487	(34,700)	-5.2%
24					
25	GS	70,671	66,907	(3,764)	-5.3%
26					
27	GSD	359,578	343,534	(16,045)	-4.5%
28					
29	IS	31,449	29,794	(1,655)	-5.3%
30					
31	Lighting	48,337	47,932	(406)	-0.8%
32					
33	TOTAL	1,180,223	1,123,654	(56,569)	-4.8%
34					
35					
36					

Supporting Schedules: E-13c, E-13d Recap Schedules:

TAMPA ELECTRIC COMPANY
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Typical Bills Reflecting

Second SoBRA Base Revenue Increase

REVISED – 09/24/2018

FLORIDA PUBLIC SERVICE COMMISSION EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

RS - RESIDENTIAL SERVICE

	RATE SCHEDULE RS		BILL UNDER PRESENT RATES							BILL UNDER PROPOSED RATES							DECREASE		COSTS IN CENTS/KWH	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
Line No.	TYPICAL KW	KWH	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	DOLLARS (16)-(9)	PERCENT (17)/(9)	PRESENT (9)/(2)*100	PROPOSED (16)/(2)*100
1	0	-	$ 15.12	$ -	$ -	$ -	$ -	$ 0.39	$ 15.51	$ 15.12	$ -	$ -	$ -	$ -	$ 0.39	$ 15.51	$ -	0.0%	-	-
2																				
3	0	100	$ 20.01	$ 2.82	$ 0.25	$ 0.07	$ 0.34	$ 0.60	$ 24.09	$ 20.26	$ 2.41	$ 0.32	$ 0.10	$ 0.22	$ 0.60	$ 23.91	$ (0.18)	-0.7%	24.09	23.91
4																				
5	0	250	$ 27.36	$ 7.05	$ 0.62	$ 0.17	$ 0.86	$ 0.92	$ 36.96	$ 27.97	$ 6.01	$ 0.80	$ 0.26	$ 0.56	$ 0.91	$ 36.51	$ (0.45)	-1.2%	14.79	14.61
6																				
7	0	500	$ 39.59	$ 14.09	$ 1.23	$ 0.33	$ 1.72	$ 1.46	$ 58.42	$ 40.83	$ 12.03	$ 1.61	$ 0.52	$ 1.11	$ 1.44	$ 57.52	$ (0.90)	-1.5%	11.68	11.50
8																				
9	0	750	$ 51.83	$ 21.14	$ 1.85	$ 0.50	$ 2.57	$ 2.00	$ 79.87	$ 53.68	$ 18.04	$ 2.41	$ 0.77	$ 1.67	$ 1.96	$ 78.53	$ (1.35)	-1.7%	10.65	10.47
10																				
11	0	1,000	$ 64.07	$ 28.18	$ 2.46	$ 0.66	$ 3.43	$ 2.53	$ 101.33	$ 66.53	$ 24.05	$ 3.21	$ 1.03	$ 2.22	$ 2.49	$ 99.53	$ (1.80)	-1.8%	10.13	9.95
12																				
13	0	1,250	$ 78.58	$ 37.73	$ 3.08	$ 0.83	$ 4.29	$ 3.19	$ 127.68	$ 81.89	$ 32.56	$ 4.01	$ 1.29	$ 2.78	$ 3.14	$ 125.67	$ (2.02)	-1.6%	10.21	10.05
14																				
15	0	1,500	$ 93.09	$ 47.27	$ 3.69	$ 0.99	$ 5.15	$ 3.85	$ 154.04	$ 97.24	$ 41.08	$ 4.82	$ 1.55	$ 3.33	$ 3.80	$ 151.80	$ (2.23)	-1.5%	10.27	10.12
16																				
17	0	2,000	$ 122.11	$ 66.36	$ 4.92	$ 1.32	$ 6.86	$ 5.17	$ 206.74	$ 127.95	$ 58.10	$ 6.42	$ 2.06	$ 4.44	$ 5.10	$ 204.07	$ (2.67)	-1.3%	10.34	10.20
18																				
19	0	3,000	$ 180.16	$ 104.54	$ 7.38	$ 1.98	$ 10.29	$ 7.80	$ 312.15	$ 189.36	$ 92.15	$ 9.63	$ 3.09	$ 6.66	$ 7.72	$ 308.61	$ (3.54)	-1.1%	10.41	10.29
20																				
21	0	5,000	$ 296.25	$ 180.90	$ 12.30	$ 3.30	$ 17.15	$ 13.07	$ 522.97	$ 312.19	$ 160.25	$ 16.05	$ 5.15	$ 11.10	$ 12.94	$ 517.68	$ (5.29)	-1.0%	10.46	10.35
22																				
23																				

Line		PRESENT	PROPOSED
24		PRESENT	PROPOSED
25	CUSTOMER CHARGE	15.12 $/Bill	15.12 $/Bill
26	DEMAND CHARGE	- $/KW	- $/KW
27	ENERGY CHARGE		
28	0 - 1,000 KWH	4.895 ¢/kWH	5.141 ¢/kWH
29	Over 1,000 KWH	5.805 ¢/kWH	6.141 ¢/kWH
30	FUEL CHARGE		
31	0 - 1,000 KWH	2.818 ¢/kWH	2.405 ¢/kWH
32	Over 1,000 KWH	3.818 ¢/kWH	3.405 ¢/kWH
33	CONSERVATION CHARGE	0.246 ¢/kWH	0.321 ¢/kWH
34	CAPACITY CHARGE	0.066 ¢/kWH	0.103 ¢/kWH
35	ENVIRONMENTAL CHARGE	0.343 ¢/kWH	0.222 ¢/kWH
36			
37	NOTES:		
38	A. Present rates include 2018 clauses, proposed rates include projected 2019 clause rates that would go into effect January 2019.		
39			

Supporting Schedules: E-13c, E-14 Supplement Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

GS - GENERAL SERVICE NON-DEMAND

	RATE SCHEDULE GS		BILL UNDER PRESENT RATES							BILL UNDER PROPOSED RATES							DECREASE		COSTS IN CENTS/KWH	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
Line No.	TYPICAL KW	KWH	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	DOLLARS (16)-(9)	PERCENT (17)/(9)	PRESENT (9)/(2)*100	PROPOSED (16)/(2)*100
1	0	-	$ 18.14	$ -	$ -	$ -	$ -	$ 0.47	$ 18.61	$ 18.14	$ -	$ -	$ -	$ -	$ 0.47	$ 18.61	$ -	0.0%	-	-
2																				
3	0	100	$ 23.30	$ 3.13	$ 0.23	$ 0.06	$ 0.34	$ 0.69	$ 27.76	$ 23.55	$ 2.72	$ 0.29	$ 0.09	$ 0.22	$ 0.69	$ 27.56	$ (0.21)	-0.7%	27.76	27.56
4																				
5	0	250	$ 31.05	$ 7.83	$ 0.58	$ 0.15	$ 0.86	$ 1.04	$ 41.50	$ 31.67	$ 6.80	$ 0.73	$ 0.22	$ 0.55	$ 1.02	$ 40.99	$ (0.52)	-1.2%	16.60	16.40
6																				
7	0	500	$ 43.96	$ 15.66	$ 1.16	$ 0.30	$ 1.72	$ 1.61	$ 64.40	$ 45.20	$ 13.60	$ 1.46	$ 0.43	$ 1.11	$ 1.58	$ 63.37	$ (1.03)	-1.6%	12.88	12.67
8																				
9	0	750	$ 56.87	$ 23.49	$ 1.74	$ 0.45	$ 2.57	$ 2.18	$ 87.30	$ 58.73	$ 20.39	$ 2.19	$ 0.65	$ 1.66	$ 2.14	$ 85.76	$ (1.55)	-1.8%	11.64	11.43
10																				
11	0	1,000	$ 69.78	$ 31.32	$ 2.32	$ 0.60	$ 3.43	$ 2.76	$ 110.20	$ 72.26	$ 27.19	$ 2.92	$ 0.86	$ 2.21	$ 2.70	$ 108.14	$ (2.06)	-1.9%	11.02	10.81
12																				
13	0	1,250	$ 82.69	$ 39.15	$ 2.90	$ 0.75	$ 4.29	$ 3.33	$ 133.10	$ 85.79	$ 33.99	$ 3.65	$ 1.08	$ 2.76	$ 3.26	$ 130.53	$ (2.58)	-1.9%	10.65	10.44
14																				
15	0	1,500	$ 95.60	$ 46.98	$ 3.48	$ 0.90	$ 5.15	$ 3.90	$ 156.00	$ 99.32	$ 40.79	$ 4.38	$ 1.29	$ 3.32	$ 3.82	$ 152.91	$ (3.09)	-2.0%	10.40	10.19
16																				
17	0	2,000	$ 121.42	$ 62.64	$ 4.64	$ 1.20	$ 6.86	$ 5.05	$ 201.80	$ 126.38	$ 54.38	$ 5.84	$ 1.72	$ 4.42	$ 4.94	$ 197.68	$ (4.12)	-2.0%	10.09	9.88
18																				
19	0	3,000	$ 173.05	$ 93.96	$ 6.96	$ 1.80	$ 10.29	$ 7.33	$ 293.40	$ 180.50	$ 81.57	$ 8.76	$ 2.58	$ 6.63	$ 7.18	$ 287.22	$ (6.18)	-2.1%	9.78	9.57
20																				
21	0	5,000	$ 276.33	$ 156.60	$ 11.60	$ 3.00	$ 17.15	$ 11.91	$ 476.60	$ 288.73	$ 135.95	$ 14.60	$ 4.30	$ 11.05	$ 11.66	$ 466.29	$ (10.31)	-2.2%	9.53	9.33
22																				
23	0	8,500	$ 457.07	$ 266.22	$ 19.72	$ 5.10	$ 29.16	$ 19.93	$ 797.19	$ 478.15	$ 231.12	$ 24.82	$ 7.31	$ 18.79	$ 19.49	$ 779.67	$ (17.52)	-2.2%	9.38	9.17

Line		PRESENT	PROPOSED
26		PRESENT	PROPOSED
27	CUSTOMER CHARGE	18.14 $/Bill	18.14 $/Bill
28	ENERGY CHARGE	5.164 ¢/kWH	5.412 ¢/kWH
29	FUEL CHARGE	3.132 ¢/kWH	2.719 ¢/kWH
30	CONSERVATION CHARGE	0.232 ¢/kWH	0.292 ¢/kWH
31	CAPACITY CHARGE	0.060 ¢/kWH	0.086 ¢/kWH
32	ENVIRONMENTAL CHARGE	0.343 ¢/kWH	0.221 ¢/kWH

36 NOTES:

37 A. Present rates include 2018 clauses, proposed rates include projected 2019 clause rates that would go into effect January 2019.

Supporting Schedules: E-13c, E-14 Supplement Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

GSD - GENERAL SERVICE DEMAND

RATE SCHEDULE GSD		BILL UNDER PRESENT RATES							BILL UNDER PROPOSED RATES							DECREASE		COSTS IN CENTS/KWH	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
TYPICAL KW	KWH	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	DOLLARS (16)-(9)	PERCENT (17)/(9)	PRESENT (9)/(2)*100	PROPOSED (16)/(2)*100
75	10,950	$ 708.82	$ 342.95	$ 22.01	$ 5.15	$ 37.45	$ 28.62	$ 1,145.00	$ 741.33	$ 297.73	$ 29.78	$ 8.21	$ 24.09	$ 28.23	$ 1,129.38	$ (15.62)	-1.4%	10.46	10.31
75	19,163	$ 1,066.06	$ 600.17	$ 65.25	$ 15.00	$ 65.54	$ 46.46	$ 1,858.48	$ 1,130.26	$ 521.03	$ 87.75	$ 24.00	$ 42.16	$ 46.29	$ 1,851.48	$ (7.00)	-0.4%	9.70	9.66
75	32,850	$ 1,284.47	$ 1,028.86	$ 65.25	$ 15.00	$ 112.35	$ 64.25	$ 2,570.18	$ 1,348.66	$ 893.19	$ 87.75	$ 24.00	$ 72.27	$ 62.20	$ 2,488.08	$ (82.10)	-3.2%	7.82	7.57
75	49,275	$ 1,504.96	$ 1,536.27	$ 65.25	$ 15.00	$ 168.52	$ 84.36	$ 3,374.36	$ 1,568.73	$ 1,334.49	$ 87.75	$ 24.00	$ 108.41	$ 80.09	$ 3,203.46	$ (170.90)	-5.1%	6.85	6.50
500	73,000	$ 4,554.08	$ 2,286.36	$ 146.73	$ 34.31	$ 249.66	$ 186.44	$ 7,457.58	$ 4,770.86	$ 1,984.87	$ 198.56	$ 54.75	$ 160.60	$ 183.84	$ 7,353.48	$ (104.11)	-1.4%	10.22	10.07
500	127,750	$ 6,935.72	$ 4,001.13	$ 435.00	$ 100.00	$ 436.91	$ 305.35	$ 12,214.11	$ 7,363.69	$ 3,473.52	$ 585.00	$ 160.00	$ 281.05	$ 304.19	$ 12,167.45	$ (46.66)	-0.4%	9.56	9.52
500	219,000	$ 8,391.76	$ 6,859.08	$ 435.00	$ 100.00	$ 748.98	$ 423.97	$ 16,958.79	$ 8,819.73	$ 5,954.61	$ 585.00	$ 160.00	$ 481.80	$ 410.29	$ 16,411.43	$ (547.36)	-3.2%	7.74	7.49
500	328,500	$ 9,861.70	$ 10,241.81	$ 435.00	$ 100.00	$ 1,123.47	$ 558.00	$ 22,319.98	$ 10,286.82	$ 8,896.60	$ 585.00	$ 160.00	$ 722.70	$ 529.52	$ 21,180.64	$ (1,139.34)	-5.1%	6.79	6.45
2000	292,000	$ 18,125.62	$ 9,145.44	$ 586.92	$ 137.24	$ 998.64	$ 743.43	$ 29,737.29	$ 18,992.72	$ 7,939.48	$ 794.24	$ 219.00	$ 642.40	$ 733.02	$ 29,320.86	$ (416.43)	-1.4%	10.18	10.04
2000	511,000	$ 27,652.17	$ 16,004.52	$ 1,740.00	$ 400.00	$ 1,747.62	$ 1,219.08	$ 48,763.40	$ 29,364.05	$ 13,894.09	$ 2,340.00	$ 640.00	$ 1,124.20	$ 1,214.42	$ 48,576.76	$ (186.64)	-0.4%	9.54	9.51
2000	876,000	$ 33,476.33	$ 27,436.32	$ 1,740.00	$ 400.00	$ 2,995.92	$ 1,693.55	$ 67,742.12	$ 35,188.20	$ 23,818.44	$ 2,340.00	$ 640.00	$ 1,927.20	$ 1,638.81	$ 65,552.66	$ (2,189.46)	-3.2%	7.73	7.48
2000	1,314,000	$ 39,356.10	$ 40,967.24	$ 1,740.00	$ 400.00	$ 4,493.88	$ 2,229.67	$ 89,186.88	$ 41,056.58	$ 35,586.41	$ 2,340.00	$ 640.00	$ 2,890.80	$ 2,115.74	$ 84,629.52	$ (4,557.37)	-5.1%	6.79	6.44

	PRESENT						PROPOSED					
	GSD	GSDT		GSD OPT.			GSD	GSDT		GSD OPT.	
CUSTOMER CHARGE	30.24	30.24	$/Bill	30.24	$/Bill		30.24	30.24		30.24	$/Bill
DEMAND CHARGE	9.73	-	$/KW	-	$/KW		10.59	-	$/KW	-	$/KW
BILLING	-	3.28	$/KW	-	$/KW		-	3.57	$/KW	-	$/KW
PEAK	-	6.45	$/KW	-	$/KW		-	7.02	$/KW	-	$/KW
ENERGY CHARGE	1.596	-	¢/KWH	6.197	¢/KWH		1.596	-	¢/KWH	6.494	¢/KWH
ON-PEAK	-	2.921	¢/KWH	-	¢/KWH		-	2.921	¢/KWH	-	¢/KWH
OFF-PEAK	-	1.054	¢/KWH	-	¢/KWH		-	1.054	¢/KWH	-	¢/KWH
FUEL CHARGE	3.132	-	¢/KWH	3.132	¢/KWH		2.719	-	¢/KWH	2.719	¢/KWH
ON-PEAK		3.330	¢/KWH	-	¢/KWH			2.874	¢/KWH	-	¢/KWH
OFF-PEAK		3.047	¢/KWH	-	¢/KWH			2.653	¢/KWH	-	¢/KWH
CONSERVATION CHARGE	0.87	0.87	$/KW	0.201	¢/KWH		1.17	1.17	$/KW	0.272	¢/KWH
CAPACITY CHARGE	0.20	0.20	$/KW	0.047	¢/KWH		0.32	0.32	$/KW	0.075	¢/KWH
ENVIRONMENTAL CHARGE	0.342	0.342	¢/KWH	0.342	¢/KWH		0.220	0.220	¢/KWH	0.220	¢/KWH

Notes:
A. The kWh for each kW group is based on 20, 35, 60, and 90% load factors (LF).
B. Charges at 20% LF are based on the GSD Option rate; 35% and 60% LF charges are based on the standard rate; and 90% LF charges are based on the TOD rate.
C. All calculations assume meter and service at secondary voltage.
D. TOD energy charges assume 25/75 on/off-peak % for 90% LF. Peak demand to billing demand ratios are assumed to be 99% at 90% LF.
E. Present rates include 2018 clauses, proposed rates include projected 2019 clause rates that would go into effect January 2019.

Supporting Schedules: E-13c, E-14 Supplement

Recap Schedules:

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
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PAGE 3 OF 4
FILED: 06/29/2018
REVISED: 09/24/2018

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY

IS - INTERRUPTIBLE SERVICE

	RATE SCHEDULE IS-1		BILL UNDER PRESENT RATES								BILL UNDER PROPOSED RATES								INCREASE/DECREASE		COSTS IN CENTS/KWH	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
Line No.	TYPICAL KW	KWH	BASE RATE	CCV CREDIT	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	BASE RATE	CCV CREDIT	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	DOLLARS (16)-(9)	PERCENT (17)/(9)	PRESENT (9)/(2)*100	FINAL (16)/(2)*100
1	500	127,750	$ 4,847	$ (1,772.75)	$ 3,961.53	$ 335.00	$ 70.00	$ 425.79	$ 202	$ 8,068	$ 5,406	$ (1,772.75)	$ 3,439.03	$ 465.00	$ 120.00	$ 273.39	$ 203.34	$ 8,133.78	$ 66	0.8%	6.32	6.37
2	500	219,000	$ 7,150	$ (3,039.00)	$ 6,791.19	$ 335.00	$ 70.00	$ 729.93	$ 309	$ 12,345	$ 7,709	$ (3,039.00)	$ 5,895.48	$ 465.00	$ 120.00	$ 468.66	$ 297.91	$ 11,916.59	$ (429)	-3.5%	5.64	5.44
3	500	328,500	$ 9,913	$ (4,558.50)	$ 10,140.80	$ 335.00	$ 70.00	$ 1,093.91	$ 436	$ 17,430	$ 10,472	$ (4,558.50)	$ 8,806.26	$ 465.00	$ 120.00	$ 702.99	$ 410.45	$ 16,418.06	$ (1,012)	-5.8%	5.31	5.00
4																						
5	1,000	255,500	$ 9,067	$ (3,545.50)	$ 7,923.06	$ 670.00	$ 140.00	$ 851.58	$ 387	$ 15,493	$ 10,185	$ (3,545.50)	$ 6,878.06	$ 930.00	$ 240.00	$ 546.77	$ 390.61	$ 15,624.59	$ 131	0.8%	6.06	6.12
6	1,000	438,000	$ 13,672	$ (6,078.00)	$ 13,582.38	$ 670.00	$ 140.00	$ 1,459.85	$ 601	$ 24,048	$ 14,790	$ (6,078.00)	$ 11,790.96	$ 930.00	$ 240.00	$ 937.32	$ 579.75	$ 23,190.21	$ (858)	-3.6%	5.49	5.29
7	1,000	657,000	$ 19,199	$ (9,117.00)	$ 20,281.59	$ 670.00	$ 140.00	$ 2,187.81	$ 855	$ 34,217	$ 20,317	$ (9,117.00)	$ 17,612.53	$ 930.00	$ 240.00	$ 1,405.98	$ 804.83	$ 32,193.14	$ (2,024)	-5.9%	5.21	4.90
8																						
9	5,000	1,277,500	$ 42,827	$ (17,727.50)	$ 39,615.28	$ 3,350.00	$ 700.00	$ 4,257.91	$ 1,872	$ 74,895	$ 48,416	$ (17,727.50)	$ 34,390.30	$ 4,650.00	$ 1,200.00	$ 2,733.85	$ 1,888.77	$ 75,551.03	$ 656	0.9%	5.86	5.91
10	5,000	2,190,000	$ 65,855	$ (30,390.00)	$ 67,911.90	$ 3,350.00	$ 700.00	$ 7,299.27	$ 2,942	$ 117,668	$ 71,443	$ (30,390.00)	$ 58,954.80	$ 4,650.00	$ 1,200.00	$ 4,686.60	$ 2,834.48	$ 113,379.13	$ (4,288)	-3.6%	5.37	5.18
11	5,000	3,285,000	$ 93,488	$ (45,585.00)	$ 101,407.95	$ 3,350.00	$ 700.00	$ 10,939.05	$ 4,213	$ 168,513	$ 99,076	$ (45,585.00)	$ 88,062.64	$ 4,650.00	$ 1,200.00	$ 7,029.90	$ 3,959.84	$ 158,393.81	$ (10,119)	-6.0%	5.13	4.82
12																						

Line No.		PRESENT IS	PRESENT IST		PROPOSED IS	PROPOSED IST	
13		PRESENT			PROPOSED		
14		IS	IST		IS	IST	
15	CUSTOMER CHARGE	626.90	626.90	$/Bill	626.90	626.90	$/Bill
16	DEMAND CHARGE	1.99	1.99	$/KW	3.11	3.11	$/KW
17	PEAK DEMAND CHARGE	-	-	$/KW	-	-	$/KW
	ENERGY CHARGE	2.524	-	¢/kWH	2.524	-	¢/kWH
18	ON-PEAK ENERGY CHARGE	-	2.524	¢/kWH	-	2.524	¢/kWH
19	OFF-PEAK ENERGY CHARGE	-	2.524	¢/kWH	-	2.524	¢/kWH
20	DELIVERY VOLTAGE CREDIT	-	-	$/KW	-	-	$/KW
21	FUEL CHARGE	3.101	-	¢/kWH	2.692	-	¢/kWH
22	ON-PEAK	-	3.297	¢/kWH	-	2.845	¢/kWH
23	OFF-PEAK	-	3.017	¢/kWH	-	2.626	¢/kWH
24	CONSERVATION CHARGE	0.67	0.67	$/KW	0.93	0.93	$/KW
25	CAPACITY CHARGE	0.14	0.14	$/KW	0.24	0.24	$/KW
26	ENVIRONMENTAL CHARGE	0.333	0.333	¢/kWH	0.214	0.214	¢/kWH
27							
28	GSLM-2 CONTRACT CREDIT VALUE	(10.13)	(10.13)	$/kW	(10.13)	(10.13)	$/kW
29							

30 Notes:
31 A. The kWh for each kW group is based on 35, 60, and 90% load factors (LF).
32 B. Charges at 35% and 60% LF are based on standard rates and charges at 90% LF are based on TOD rates. Peak demand to billing demand ratios are assumed to be 99% at 90% LF.
33 C. Calculations assume meter and service at primary voltage and a power factor of 85%.
34 D. TOD energy charges assume 25/75 on/off-peak % for 90% LF.
35 E. CCV credits in columns 5 and 12 are load-factor adjusted and reflect service at primary voltage.
36 F. The present GSLM-2 Contract Credit Value represents the 2018 factor. The proposed GSLM-2 Contract Credit Value for 2019 is the same.
37 G. Present rates include 2018 clauses, proposed rates include projected 2019 clause rates that would go into effect January 2019.
38
39

Supporting Schedules: E-13c, E-14 Supplement

Recap Schedules:

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
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FILED: 06/29/2018
REVISED: 09/24/2018

Determination of Fuel Recovery Factor

for Second SoBRA

TAMPA ELECTRIC COMPANY
DETERMINATION OF FUEL RECOVERY FACTOR FOR SECOND SoBRA
ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019
FUEL SAVINGS - $17.2 M ANNUALLY

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	30.13	$24.05
OFF PEAK	69.87	$22.01
	100.00	1.0927

			TOTAL		ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)		$627,802,929	3.2197		
2	MWH Sales (Jurisd)		19,544,119			
2a	Effective MWH Sales (Jurisd)		19,512,919			
3	Cost Per KWH Sold	(line 1 / line 2)	3.2122			
4	Jurisdictional Loss Factor		1.00000			
5	Jurisdictional Fuel Factor		na			
6	True-Up		($17,081,137)	-0.0876		
6a	First SoBRA Fuel Savings (8 of 12 months)		($6,600,000)			
6b	Second SoBRA Fuel Savings		($17,200,000)			
7	TOTAL	(line 1 x line 4)+line 6	$586,921,792			
8	Revenue Tax Factor		1.00072			
9	Recovery Factor	(line 7 x line 8) / line 2a	3.0100			
10	GPIF Factor		0.0002	0.0002		
11	Recovery Factor Including GPIF	(line 9 + line 10)	3.0102	3.1323	3.1999	2.9285
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.010		3.200	2.929

	Jurisdictional Sales (MWH)	
Metering Voltage:	Meter	Secondary
Distribution Secondary	17,160,490	17,160,490
Distribution Primary	1,647,281	1,630,808
Transmission	736,348	721,621
Total	19,544,119	19,512,919

Rate Schedules		2018 Approved Rates with First & Second SoBRA Fuel Savings *			2018 Approved Rates including First SoBRA incremental $6.6 M Fuel Savings**			Rate Impact of Second SoBRA Fuel Savings ***		
		Standard	On-Peak	Off-Peak	Standard	On-Peak	Off-Peak	Standard	On-Peak	Off-Peak
RSVP, GS, GST, CS, GSD (Opt), GSD, GSDT, SBF, SBFT	Distribution Secondary	3.010	3.200	2.929	3.098	3.294	3.014	-0.088	-0.094	-0.085
GSD (Opt), GSD, GSDT, SBF, SBFT, IS, IST, SBI	Distribution Primary	2.980	3.168	2.900	3.067	3.261	2.984	-0.087	-0.093	-0.084
GSD (Opt), GSD, GSDT, SBF, SBFT, IS, IST, SBI	Transmission	2.950	3.136	2.870	3.036	3.228	2.954	-0.086	-0.092	-0.084
	RS 1st Tier	2.696			2.784			-0.088		
	RS 2nd Tier	3.696			3.784			-0.088		
	Lighting	2.975			3.095			-0.120		

* Calculated above. Includes First SoBRA annual fuel savings of $9.9 ($3.3 in 2018 approved rates and $6.6 incremental amount) and $17.2 Second SoBRA annual fuel savings.
** Current approved rates per tariff schedules less First SoBRA fuel savings.
*** Current approved rates and total annual First and Second SoBRA fuel savings of $27.1 M, less 2018 rates including First SoBRA annual fuel savings of $9.9 M.

TAMPA ELECTRIC COMPANY
DOCKET NO. 2018____-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
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Redlined Tariffs

Reflecting Second SoBRA Base Revenue Increase

SUBSTITUTED - 09/24/2018

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTY-~~THIRD~~ FOURTH REVISED SHEET NO. 6.030
CANCELS TWENTY-~~SECOND~~ THIRD REVISED SHEET NO. 6.030

RESIDENTIAL SERVICE

SCHEDULE: RS

AVAILABLE: Entire service area.

APPLICABLE: To residential consumers in individually metered private residences, apartment units, and duplex units. All energy must be for domestic purposes and should not be shared with or sold to others. In addition, energy used in commonly-owned facilities in condominium and cooperative apartment buildings will qualify for this rate schedule, subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owners' benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery will be separately metered and billed.
4. A responsible legal entity is established as the customer to whom the Company can render its bills for said service.

Resale not permitted.

Billing charges shall be prorated for billing periods that are less than 25 days or greater than 35 days. If the billing period exceeds 35 days and the billing extension causes energy consumption, based on average daily usage, to exceed 1,000 kWh, the excess consumption will be charged at the lower monthly Energy and Demand Charge.

LIMITATION OF SERVICE: This schedule includes service to single phase motors rated up to 7.5 HP. Three phase service may be provided where available for motors rated 7.5 HP and over.

MONTHLY RATE:

Basic Service Charge:
$~~16.62~~15.12

Energy and Demand Charge:

First 1,000 kWh	5.~~381~~141¢ per kWh
All additional kWh	6.~~381~~141¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.031

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-~~FOURTH~~ FIFTH REVISED SHEET NO. 6.050
CANCELS TWENTY-~~THIRD~~ FOURTH REVISED SHEET NO. 6.050

GENERAL SERVICE - NON DEMAND

SCHEDULE: GS

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted on Schedule GST only.

MONTHLY RATE:

Basic Service Charge:
Metered accounts $~~19.94~~18.14
Un-metered accounts $~~16.62~~15.12

Energy and Demand Charge:
5.~~676~~412¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.~~171~~164¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.051

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-~~THIRD~~ FOURTH REVISED SHEET NO. 6.080
CANCELS TWENTY-~~SECOND~~ THIRD REVISED SHEET NO. 6.080

GENERAL SERVICE - DEMAND

SCHEDULE: GSD

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

STANDARD		OPTIONAL	
Basic Service Charge:		Basic Service Charge:	
Secondary Metering Voltage	$ ~~33.24~~30.24	Secondary Metering Voltage	$ ~~33.24~~30.24
Primary Metering Voltage	$ ~~144.03~~131.03	Primary Metering Voltage	$ ~~144.03~~131.03
Subtrans. Metering Voltage	$~~1,096.82~~997.80	Subtrans. Metering Voltage	$~~1,096.82~~997.80

Demand Charge:
$10.~~70~~ 59 per kW of billing demand

Energy Charge:
1.~~754~~596¢ per kWh

Demand Charge (Optional):
$0.00 per kW of billing demand

Energy Charge (Optional):
6.~~812~~494¢ per kWh

The customer may select either standard or optional. Once an option is selected, the customer must remain on that option for twelve (12) consecutive months.

Continued to Sheet No. 6.081

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-~~FIRST~~ SECOND REVISED SHEET NO. 6.081
CANCELS ~~TWENTIETH~~ TWENTY-FIRST REVISED SHEET NO. 6.081

Continued from Sheet No. 6.080

BILLING DEMAND: The highest measured 30-minute interval kW demand during the billing period.

MINIMUM CHARGE: The Basic Service Charge and any Minimum Charge associated with optional riders.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW or more in any one billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When a customer under the standard rate takes service at primary voltage, a discount of ~~87~~86¢ per kW of billing demand will apply. A discount of $2.~~69~~66 per kW of billing demand will apply when a customer under the standard rate takes service at subtransmission or higher voltage.

Continued to Sheet No. 6.082

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~EIGHTH~~ NINTH REVISED SHEET NO. 6.082
CANCELS ~~SEVENTH~~ EIGHTH REVISED SHEET NO. 6.082

Continued from Sheet No. 6.081

When a customer under the optional rate takes service at primary voltage, a discount of 0.~~230~~228¢ per kWh will apply. A discount of 0.~~702~~695¢ per kWh will apply when a customer under the optional rate takes service at subtransmission or higher voltage.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~69~~68¢ per kW of billing demand for customers taking service under the standard rate and 0.~~174~~172¢/kWh for customer taking service under the optional rate. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTY-~~FIRST~~ SECOND REVISED SHEET NO. 6.085
CANCELS ~~TWENTIETH~~ TWENTY-FIRST REVISED SHEET NO. 6.085

INTERRUPTIBLE SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: IS

AVAILABLE: Entire Service Area.

APPLICABLE: To be eligible for service under Rate Schedule IS, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Agreement for the Purchase of Industrial Load Management Service under Rate Schedule GSLM-2. When electric service is desired at more than one location, each such location or point of delivery shall be considered as a separate customer. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$ ~~689.11~~626.90
Subtransmission Metering Voltage	$~~2,627.94~~2,390.70

Demand Charge:
$~~2.19~~3.11 per KW of billing demand

Energy Charge:
2.~~774~~524¢ per KWH

Continued to Sheet No. 6.086

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~TWENTIETH~~ TWENTY-FIRST REVISED SHEET NO. 6.086
CANCELS ~~NINETEENTH~~ TWENTIETH REVISED SHEET NO. 6.086

Continued from Sheet No. 6.085

BILLING DEMAND: The highest measured 30-minute interval KW demand during the month.

MINIMUM CHARGE: The Basic Service Charge and any Minimum Charge associated with optional riders.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% of the energy and demand charge will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of ~~60~~85¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~86¢~~$1.22 per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.087

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~TWENTY-NINTH~~THIRTIETH REVISED SHEET NO. 6.290
CANCELS TWENTY-~~EIGHTH~~ NINTH REVISED SHEET NO. 6.290

CONSTRUCTION SERVICE

SCHEDULE: CS

AVAILABLE: Entire service area.

APPLICABLE: Single phase temporary service used primarily for construction purposes.

LIMITATION OF SERVICE: Service is limited to construction poles and services installed under the TUG program. Construction poles are limited to a maximum of 70 amperes at 240 volts for construction poles. Larger (non-TUG) services and three phase service entrances must be served under the appropriate rate schedule, plus the cost of installing and removing the temporary facilities is required.

MONTHLY RATE:
Basic Service Charge: $~~19.94~~18.14

Energy and Demand Charge: 5.~~676~~412¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

MISCELLANEOUS: A Temporary Service Charge of $260.00 shall be paid upon application for the recovery of costs associated with providing, installing, and removing the company's temporary service facilities for construction poles. Where the Company is required to provide additional facilities other than a service drop or connection point to the Company's existing distribution system, the customer shall also pay, in advance, for the estimated cost of providing, installing and removing such additional facilities, excluding the cost of any portion of these facilities which will remain as a part of the permanent service.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-~~THIRD~~ FOURTH REVISED SHEET NO. 6.320
CANCELS TWENTY-~~SECOND~~ THIRD REVISED SHEET NO. 6.320

TIME-OF-DAY
GENERAL SERVICE - NON DEMAND
(OPTIONAL)

SCHEDULE: GST

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. All of the electric load requirements on the customer's premises must be metered at one (1) point of delivery. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted.

MONTHLY RATE:

Basic Service Charge:
$~~22.16~~20.16

Energy and Demand Charge:
14.~~488~~963¢ per kWh during peak hours
~~1.545~~2.108¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~NINETEENTH~~ TWENTIETH REVISED SHEET NO. 6.321
CANCELS ~~EIGHTEENTH~~ NINETEENTH REVISED SHEET NO. 6.321

Continued from Sheet No. 6.320

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

MINIMUM CHARGE: The Basic Service Charge.

BASIC SERVICE CHARGE CREDIT: Any customer who makes a one time contribution in aid of construction of $94.00 (lump-sum meter payment), shall receive a credit of $2.~~22~~ 02 per month. This contribution in aid of construction will be subject to a partial refund if the customer terminates service on this optional time-of-day rate.

TERMS OF SERVICE: A customer electing this optional rate shall have the right to transfer to the standard applicable rate at any time without additional charge for such transaction, except that any customer who requests this optional rate for the second time on the same premises will be required to sign a contract to remain on this rate for at least one (1) year.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.~~171~~164¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.322

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-~~FOURTH~~ FIFTH REVISED SHEET NO. 6.330
CANCELS TWENTY-~~THIRD~~ FOURTH REVISED SHEET NO. 6.330

TIME-OF-DAY
GENERAL SERVICE - DEMAND
(OPTIONAL)

SCHEDULE: GSDT

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ ~~33.24~~30.24
Primary Metering Voltage	$ ~~144.03~~131.03
Subtransmission Metering Voltage	$~~1,096.82~~ 997.80

Demand Charge:

$3.~~61~~ 57 per kW of billing demand, plus
$7.~~09per~~ 02 per kW of peak billing demand

Energy Charge:

~~3.211~~2.921¢ per kWh during peak hours
1.~~159~~054¢ per kWh during off-peak hours

Continued to Sheet No. 6.331

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~TWENTIETH~~ TWENTY-FIRST REVISED SHEET NO. 6.332
CANCELS ~~NINETEENTH~~ TWENTIETH REVISED SHEET NO. 6.332

Continued from Sheet No. 6.331

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage a discount of ~~87~~86¢ per kW of billing demand will apply. When the customer takes service at subtransmission or higher voltage, a discount of $2.~~69~~ 66 per kW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~69~~68¢ per kW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-~~FIRST~~ SECOND REVISED SHEET NO. 6.340
CANCELS ~~TWENTIETH~~ TWENTY-FIRST REVISED SHEET NO. 6.340

TIME OF DAY
INTERRUPTIBLE SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: IST

AVAILABLE: Entire Service Area.

APPLICABLE: To be eligible for service under Rate Schedule IST, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Agreement for the Purchase of Industrial Load Management Service under Rate Schedule GSLM-2. When electric service is desired at more than one location, each such location or point of delivery shall be considered as a separate customer. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

Basic Service Charge:

Primary Metering Voltage	$ ~~689.11~~626.90
Subtransmission Metering Voltage	$~~2,627.94~~2,390.70

Demand Charge:
$~~2.19~~3.11 per KW of billing demand

Energy Charge:
2.~~774~~524¢ per KWH

Continued to Sheet No. 6.345

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTY-~~SIXTH~~ SEVENTH REVISED SHEET NO. 6.350
CANCELS TWENTY-~~FIFTH~~ SIXTH REVISED SHEET NO. 6.350

Continued from Sheet No. 6.345

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% of the energy and demand charge will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of ~~60~~85¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~86¢~~$1.22 per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.025.

~~NINTH~~ TENTH REVISED SHEET NO. 6.565
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 6.565

Continued from Sheet No. 6.560

MONTHLY RATES:
Basic Service Charge: $~~16.62~~15.12

Energy and Demand Charges: 5.~~695~~455¢ per kWh (for all pricing periods)

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

DETERMINATION OF PRICING PERIODS: Pricing periods are established by season for weekdays and weekends. The pricing periods for price levels P_1 (Low Cost Hours), P_2 (Moderate Cost Hours) and P_3 (High Cost Hours) are as follows:

May through October	P_1	P_2	P_3
Weekdays	11 P.M. to 6 A.M.	6 A.M. to 1 P.M. 6 P.M. to 11 P.M.	1 P.M. to 6 P.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

November through April	P_1	P_2	P_3
Weekdays	11 P.M. to 5 A.M.	5 A.M. to 6 A.M. 10 A.M. to 11 P.M.	6 A.M. to 10 A.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

The pricing periods for price level P_4 (Critical Cost Hours) shall be determined at the sole discretion of the Company. Level P_4 hours shall not exceed 134 hours per year.

Continued to Sheet No. 6.570

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~FOURTEENTH~~ FIFTEENTH REVISED SHEET NO. 6.601
CANCELS ~~THIRTEENTH~~ FOURTEENTH REVISED SHEET NO. 6.601

Continued from Sheet No. 6.600

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$10.~~70~~59 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.~~754~~596¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.602

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~SIXTEENTH~~ SEVENTIETH REVISED SHEET NO. 6.603
CANCELS ~~FIFTEENTH~~ SIXTEENTH REVISED SHEET NO. 6.603

Continued from Sheet No. 6.602

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of ~~87~~86¢ per kW of Supplemental Demand and ~~69~~63¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.~~69~~ 66 per kW of Supplemental Demand and $~~2.16~~1.97 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~69~~68¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021. Note: Standby fuel charges shall be based on the time of use (i.e., peak and off-peak) fuel rates for Rate Schedule SBF. Supplemental fuel charges shall be based on the standard fuel rate for Rate Schedule SBF.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~ELEVENTH~~ TWELFTH REVISED SHEET NO. 6.606
CANCELS ~~TENTH~~ ELEVENTH REVISED SHEET NO. 6.606

Continued from Sheet No. 6.605

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$3.~~61~~57	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$7.~~09~~02	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

~~3.211~~2.921¢	per Supplemental kWh during peak hours
1.~~159~~054¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest measured 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Continued to Sheet No. 6.607

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Continued from Sheet No. 6.607

TERM OF SERVICE: Any customer receiving service under this schedule will be required to give the Company written notice at least 60 months prior to transferring to a firm non-standby schedule. Such notice shall be irrevocable unless the Company and the customer should mutually agree to void the notice.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charges, Energy Charges, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charges, Energy Charges, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of ~~87~~86¢ per kW of Supplemental Demand and ~~69~~63¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.~~69~~ 66 per kW of Supplemental Demand and $~~2.15~~1.97 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~69~~68¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.609

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~NINTH~~ TENTH REVISED SHEET NO. 6.700
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 6.700

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: SBI

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating customers eligible for service under rate schedules IS or IST whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to self-generating customers eligible for service under rate schedules IS or IST whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. To be eligible for service under this rate schedule, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Supplemental Tariff Agreement for the Purchase of Industrial Standby and Supplemental Load Management Rider Service. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher

LIMITATION OF SERVICE: A customer taking service under this tariff must sign the Tariff Agreement for the Purchase of Standby and Supplemental Service

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$~~716.81~~652.10
Subtransmission Metering Voltage	$~~2,655.64~~2,415.90

Demand Charge:

$~~2.19~~3.11 per KW-Month of Supplemental Demand (Supplemental Demand Charge)
$1.~~61~~ 46 per KW-Month of Standby Demand (Local Facilities Reservation Charge)

plus the greater of:
$1.~~33~~ 21 per KW-Month of Standby Demand (Power Supply Reservation Charge); or
$0.~~53~~ 48 per KW-Day of Actual Standby Billing Demand (Power Supply Demand Charge)

Continued to Sheet No. 6.705

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~SEVENTH~~ EIGHTH REVISED SHEET NO. 6.715
CANCELS ~~SIXTH~~ SEVENTH REVISED SHEET NO. 6.715

Continued from Sheet No. 6.710

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% will apply to the standby and supplemental demand charges, energy charges, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charges.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of ~~60~~85¢ per KW of Supplemental Demand and ~~37~~34¢ per KW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~86¢~~$1.22 per KW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: Supplemental energy may be billed at either standard or time-of-day fuel rates at the option of the customer. See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~SEVENTH~~ EIGHTH REVISED SHEET NO. 6.805
CANCELS ~~SIXTH~~ SEVENTH REVISED SHEET NO. 6.805

Continued from Sheet No. 6.800

MONTHLY RATE:

High Pressure Sodium Fixture, Maintenance, and Base Energy Charges:

Rate Code		Description	Lamp Size				Charges per Unit ($)			
					kWh				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
800	860	Cobra[1]	4,000	50	20	10	3.16	2.48	0.55	0.27
802	862	Cobra/Nema[1]	6,300	70	29	14	3.20	2.11	0.79	0.38
803	863	Cobra/Nema[1]	9,500	100	44	22	3.63	2.33	1.20	0.60
804	864	Cobra[1]	16,000	150	66	33	4.18	2.02	1.80	0.90
805	865	Cobra[1]	28,500	250	105	52	4.87	2.60	2.86	1.42
806	866	Cobra[1]	50,000	400	163	81	5.09	2.99	4.45	2.21
468	454	Flood[1]	28,500	250	105	52	5.37	2.60	2.86	1.42
478	484	Flood[1]	50,000	400	163	81	5.71	3.00	4.45	2.21
809	869	Mongoose[1]	50,000	400	163	81	6.50	3.02	4.45	2.21
509	508	Post Top (PT)[1]	4,000	50	20	10	3.98	2.48	0.55	0.27
570	530	Classic PT[1]	9,500	100	44	22	11.85	1.89	1.20	0.60
810	870	Coach PT[1]	6,300	70	29	14	4.71	2.11	0.79	0.38
572	532	Colonial PT[1]	9,500	100	44	22	11.75	1.89	1.20	0.60
573	533	Salem PT[1]	9,500	100	44	22	9.03	1.89	1.20	0.60
550	534	Shoebox[1]	9,500	100	44	22	8.01	1.89	1.20	0.60
566	536	Shoebox[1]	28,500	250	105	52	8.69	3.18	2.86	1.42
552	538	Shoebox[1]	50,000	400	163	81	9.52	2.44	4.45	2.21

(1) Closed to new business
(2) Lumen output may vary by lamp configuration and age.
(3) Wattage ratings do not include ballast losses.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.~~741~~509¢ per kWh for each fixture.

Continued to Sheet No. 6.806

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~FIFTH~~ SIXTH REVISED SHEET NO. 6.806
CANCELS ~~FOURTH~~ FIFTH REVISED SHEET NO. 6.806

Continued from Sheet No. 6.805

MONTHLY RATE:

Metal Halide Fixture, Maintenance, and Base Energy Charges:

Rate Code		Description	Lamp Size				Charges per Unit ($)			
					kWh				Base Energy[4]	
Dusk to Dawn	Timed Svc.		Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
704	724	Cobra[1]	29,700	350	138	69	7.53	4.99	3.76	1.88
520	522	Cobra[1]	32,000	400	159	79	6.03	4.01	4.34	2.15
705	725	Flood[1]	29,700	350	138	69	8.55	5.04	3.76	1.88
556	541	Flood[1]	32,000	400	159	79	8.36	4.02	4.34	2.15
558	578	Flood[1]	107,800	1,000	383	191	10.50	8.17	10.44	5.21
701	721	General PT[1]	12,000	150	67	34	10.60	3.92	1.83	0.93
574	548	General PT[1]	14,400	175	74	37	10.89	3.73	2.02	1.01
700	720	Salem PT[1]	12,000	150	67	34	9.33	3.92	1.83	0.93
575	568	Salem PT[1]	14,400	175	74	37	9.38	3.74	2.02	1.01
702	722	Shoebox[1]	12,000	150	67	34	7.22	3.92	1.83	0.93
564	549	Shoebox[1]	12,800	175	74	37	7.95	3.70	2.02	1.01
703	723	Shoebox[1]	29,700	350	138	69	9.55	4.93	3.76	1.88
554	540	Shoebox[1]	32,000	400	159	79	10.02	3.97	4.34	2.15
576	577	Shoebox[1]	107,800	1,000	383	191	16.50	8.17	10.44	5.21

(1) Closed to new business
(2) Lumen output may vary by lamp configuration and age.
(3) Wattage ratings do not include ballast losses.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.~~741~~509¢ per kWh for each fixture.

Continued to Sheet No. 6.808

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~SIXTH~~ SEVENTH REVISED SHEET NO. 6.808
CANCELS ~~FIFTH~~ SIXTH REVISED SHEET NO. 6.808

Continued from Sheet No. 6.806

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

Rate Code			Size				Charges per Unit ($)			
					kWh(1)				Base Energy(4)	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens(2)	Lamp Wattage(3)	Dusk to Dawn	Timed Svc.	Fixture	Maintenance	Dusk to Dawn	Timed Svc.
828	848	Roadway(1)	5,155	56	20	10	7.27	1.74	0.55	0.27
820	840	Roadway (1)	7,577	103	36	18	11.15	1.19	0.98	0.49
821	841	Roadway(1)	8,300	106	37	19	11.15	1.20	1.01	0.52
829	849	Roadway(1)	15,285	157	55	27	11.10	2.26	1.50	0.74
822	842	Roadway(1)	15,300	196	69	34	14.58	1.26	1.88	0.93
823	843	Roadway(1)	14,831	206	72	36	16.80	1.38	1.96	0.98
835	855	Post Top(1)	5,176	60	21	11	16.53	2.28	0.57	0.30
824	844	Post Top(1)	3,974	67	24	12	19.67	1.54	0.65	0.33
825	845	Post Top(1)	6,030	99	35	17	20.51	1.56	0.95	0.46
836	856	Post Top(1)	7,360	100	35	18	16.70	2.28	0.95	0.49
830	850	Area-Lighter(1)	14,100	152	53	27	14.85	2.51	1.45	0.74
826	846	Area-Lighter(1)	13,620	202	71	35	19.10	1.41	1.94	0.95
827	847	Area-Lighter(1)	21,197	309	108	54	20.60	1.55	2.95	1.47
831	851	Flood(1)	22,122	238	83	42	15.90	3.45	2.26	1.15
832	852	Flood(1)	32,087	359	126	63	19.16	4.10	3.44	1.72
833	853	Mongoose(1)	24,140	245	86	43	14.71	3.04	2.35	1.17
834	854	Mongoose(1)	32,093	328	115	57	16.31	3.60	3.14	1.55

(1) Closed to new business
(2) Average
(3) Average wattage. Actual wattage may vary by up to +/- 5 watts.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.~~741~~509¢ per kWh for each fixture.

Continued to Sheet No. 6.810

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FIRST~~ SECOND REVISED SHEET NO. 6.809
CANCELS ~~ORIGINAL~~ FIRST REVISED SHEET NO. 6.809

Continued from Sheet No. 6.808

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

Rate Code			Size				Charges per Unit ($)			
					kWh(1)				Base Energy(3)	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens(1)	Lamp Wattage(2)	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
912	981	Roadway	2,600	27	9	5	4.83	1.74	0.25	0.14
914		Roadway	5,392	47	16		5.97	1.74	0.44	
921		Roadway/Area	8,500	88	31		8.97	1.74	0.85	
926	982	Roadway	12,414	105	37	18	6.83	1.19	1.01	0.49
932		Roadway/Area	15,742	133	47		14.15	1.38	1.28	
935		Area-Lighter	16,113	143	50		11.74	1.41	1.36	
937		Roadway	16,251	145	51		8.61	2.26	1.39	
941	983	Roadway	22,233	182	64	32	11.81	2.51	1.75	0.87
945		Area-Lighter	29,533	247	86		16.07	2.51	2.35	
947	984	Area-Lighter	33,600	330	116	58	20.13	1.55	3.16	1.58
951	985	Flood	23,067	199	70	35	11.12	3.45	1.91	0.95
953	986	Flood	33,113	255	89	45	21.48	4.10	2.43	1.23
956	987	Mongoose	23,563	225	79	39	11.78	3.04	2.15	1.06
958		Mongoose	34,937	333	117		17.84	3.60	3.19	
965		Granville Post Top (PT)	3,024	26	9		5.80	2.28	0.25	
967	988	Granville PT	4,990	39	14	7	13.35	2.28	0.38	0.19
968	989	Granville PT Enh(4)	4,476	39	14	7	15.35	2.28	0.38	0.19
971		Salem PT	5,240	55	19		10.95	1.54	0.52	
972		Granville PT	7,076	60	21		14.62	2.28	0.57	
973		Granville PT Enh(4)	6,347	60	21		16.62	2.28	0.57	
975	990	Salem PT	7,188	76	27	13	13.17	1.54	0.74	.35

(1) Average
(2) Average wattage. Actual wattage may vary by up to +/- 10 %.
(3) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.~~741~~509¢ per kWh for each fixture.
(4) Enhanced Post Top. Customizable decorative options

Continued to Sheet No. 6.810

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

Continued from Sheet No. 6.810

Miscellaneous Facilities Charges:

Rate Code	Description	Monthly Facility Charge	Monthly Maintenance Charge
563	Timer	$7.54	$1.43
569	PT Bracket (accommodates two post top fixtures)	$4.27	$0.06

NON-STANDARD FACILITIES AND SERVICES:

The customer shall pay all costs associated with additional company facilities and services that are not considered standard for providing lighting service, including but not limited to, the following:

1. relays;
2. distribution transformers installed solely for lighting service;
3. protective shields;
4. bird deterrent devices;
5. light trespass shields;
6. light rotations;
7. light pole relocations;
8. devices required by local regulations to control the levels or duration of illumination including associated planning and engineering costs;
9. removal and replacement of pavement required to install underground lighting cable; and
10. directional boring.

MINIMUM CHARGE: The monthly charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021

FRANCHISE FEE: See Sheet No. 6.021

PAYMENT OF BILLS: See Sheet No. 6.022

SPECIAL CONDITIONS:
On customer-owned public street and highway lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 2.~~741~~509¢ per kWh of metered usage, plus a Basic Service Charge of $~~11.62~~10.57 per month and the applicable additional charges as specified on Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.820

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 6.1

Additional Proposed Redlined Tariff Sheets

Reflecting the Tampa Electric Tax Reform Docket

Continued from Sheet No. 6.340

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

Peak Hours:	April 1 - October 31	November 1 - March 31
(Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING DEMAND: The highest measured 30-minute interval KW demand during the billing period.

MINIMUM CHARGE: The Basic Service Charge and any Minimum Charge associated with optional riders.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

Continued to Sheet No. 6.350

~~THIRTEENTH~~ FOURTEENTH
REVISED SHEET NO. 6.600
CANCELS ~~TWELFTH~~
THIRTEENTH REVISED SHEET
NO. 6.600

FIRM STANDBY AND SUPPLEMENTAL SERVICE

SCHEDULE: SBF

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ ~~60.93~~55.43
Primary Metering Voltage	$ ~~171.72~~156.22
Subtransmission Metering Voltage	$~~1,124.52~~1,023.00

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ ~~2.15~~1.96 per kW-Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ 1.~~71~~56 per kW-Month of Standby Demand
(Power Supply Reservation Charge) or

$ 0.~~68~~62 per kW-Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

~~1.012~~0.921¢ per Standby kWh

Continued to Sheet No. 6.601

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President **DATE EFFECTIVE:** ~~January 16, 2017~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FIFTH~~ SIXTH REVISED SHEET NO. 6.602
CANCELS ~~FOURTH~~ FIFTH REVISED SHEET NO. 6.602

Continued from Sheet No. 6.601

Contract Standby Demand - As established pursuant to the Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. Anytime a customer registers a Standby Demand that is higher than the existing Contract Standby Demand, that Standby Demand will become the new Contract Standby Demand, beginning with the following period.

Standby Demand - The greater of Contract Standby Demand or the amount by which Metered Demand exceeds Supplemental Billing Demand, but no greater than Normal Generation.

Actual Standby Billing Demand - The summation of the daily amounts by which the highest on-peak measured 30-minute interval kW demands served by the Company exceed the monthly Supplemental Billing Demand.

Energy Units: Energy provided by the Company during each 30-minute period up to the Supplemental Demand level shall be billed as Supplemental kWh. The remaining energy shall be billed as Standby kWh.

MINIMUM CHARGE: The Basic Service Charge, Local Facilities Reservation Charge, Power Supply Reservation Charge, and any Minimum Charge associated with optional riders.

TERM OF SERVICE: Any customer receiving service under this schedule will be required to give the Company written notice at least 60 months prior to transferring to a firm non-standby schedule. Such notice shall be irrevocable unless the Company and the customer should mutually agree to void the notice.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

Continued to Sheet No. 6.603

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~TENTH~~ ELEVENTH REVISED SHEET NO. 6.605
CANCELS ~~NINTH~~ TENTH REVISED SHEET NO. 6.605

TIME-OF-DAY
FIRM STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

SCHEDULE: SBFT

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ ~~60.93~~55.43
Primary Metering Voltage	$ ~~171.72~~156.22
Subtransmission Metering Voltage	$~~1,124.52~~1,023.00

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ ~~2.15~~1.96	per kW-Month of Standby Demand (Local Facilities Reservation Charge)
plus the greater of:	
$ 1.~~71~~56	per kW-Month of Standby Demand (Power Supply Reservation Charge) or
$ 0.~~68~~62	per kW-Day of Actual Standby Billing Demand (Power Supply Demand Charge)

Energy Charge:

~~1.012~~0.921¢ per Standby kWh

Continued to Sheet No. 6.606

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President **DATE EFFECTIVE:** ~~January 16, 2017~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FOURTH~~ FIFTH REVISED SHEET NO. 6.705
CANCELS ~~THIRD~~ FOURTH REVISED SHEET NO. 6.705

Continued from Sheet No. 6.700

Energy Charge:
2.~~774~~524¢ per Supplemental KWH
1.~~115~~014¢ per Standby KWH

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval KW demand served by the company during the month.

Site Load - The highest KW total of Customer generation plus deliveries by the Company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.710

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

~~NINTH~~ TENTH REVISED SHEET NO. 8.070
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 8.070

Continued from Sheet No. 8.061

CHARGES/CREDITS TO QUALIFYING FACILITY

A. Basic Service Charges

A monthly Basic Service Charge will be rendered for maintaining an account for a Qualifying Facility engaged in either an As-Available Energy or Firm Capacity and Energy transaction and for other applicable administrative costs. Actual charges will depend on how the QF is interconnected to the Company.

QFs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

Monthly Basic Service charges, applicable to QFs directly interconnected to the Company, by Rate Schedule are:

Rate Schedule	Basic Service Charge ($)	Rate Schedule	Basic Service Charge ($)
RS	15.~~00~~12	GST	20.~~00~~16
GS	18.~~00~~14	GSDT (secondary)	30.~~00~~24
GSD (secondary)	30.~~00~~24	GSDT (primary)	~~130.00~~131.03
GSD (primary)	~~130.00~~131.03	GSDT (subtrans.)	~~990.00~~997.80
GSD (subtrans.)	~~990.00~~997.80	SBFT (secondary)	55.~~00~~43
SBF (secondary)	55.~~00~~43	SBFT (primary)	~~155.00~~156.22
SBF (primary)	~~155.00~~156.22	SBFT (subtrans.)	~~1,015.00~~1,023.00
SBF (subtrans.)	~~1,015.00~~ 1,023.00	IST (primary)	~~622.00~~626.90
IS (primary)	~~622.00~~ 626.90	IST (subtrans.)	~~2,372.00~~2,390.70
IS (subtrans.)	~~2,372.00~~2,390.70		
SBI (primary)	~~647.00~~652.10		
SBI (subtrans.)	~~2,397.00~~2415.90		

When appropriate, the Basic Service Charge will be deducted from the Qualifying Facility's monthly payment. A statement of the charges or payments due the Qualifying Facility will be rendered monthly. Payment normally will be made by the twentieth business day following the end of the billing period.

Continued to Sheet No. 8.071

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~June 20, 2014~~

~~SECOND~~ THIRD REVISED SHEET NO. 8.312
CANCELS ~~FIRST~~ SECOND REVISED SHEET NO. 8.312

Continued from Sheet No. 8.308

Should the CEP elect a Net Billing Arrangement, the hourly net capacity and energy sales delivered to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C. Purchases from the interconnecting utility shall be billed at the retail rate schedule, under which the CEP load would receive service as a customer of the utility.

Although a billing option may be changed in accordance with FPSC Rule 25-17.082, F.A.C., the Contracted Capacity may only change through mutual negotiations satisfactory to the CEP and the Company.

Basic Service charges that are directly attributable to the purchase of firm capacity and energy from the CEP are deducted from the CEP's total monthly payment. A statement covering the charges and payments due the CEP is rendered monthly and payment normally is made by the 20th business day following the end of the Monthly Period.

CHARGES/CREDITS TO THE CEP:

1. **Basic Service Charges:** A monthly Basic Service Charge will be rendered for maintaining an account for the CEP engaged in either an As-Available Energy or firm capacity and energy transaction and for other applicable administrative costs. Actual charges will depend on how the CEP is interconnected to the Company.

   CEPs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

   Monthly Basic Service charges, applicable to CEPs directly interconnected to the Company, by Rate Schedule are:

RATE SCHEDULE	BASIC SERVICE CHARGE ($)	RATE SCHEDULE	BASIC SERVICE CHARGE ($)
RS	15.~~00~~12		
GS	18.~~00~~14	GST	20.~~00~~16
GSD (secondary)	30.~~00~~ 24	GSDT (secondary)	30.~~00~~24
GSD (primary)	~~130.00~~131.03	GSDT (primary)	~~130.00~~ 131.03
GSD (subtrans.)	~~990.00~~997.80	GSDT (subtrans.)	~~990.00~~997.80
SBF (secondary)	55.~~00~~43	SBFT (secondary)	55.~~00~~43
SBF (primary)	~~155.00~~156.22	SBFT (primary)	~~155.00~~156.22
SBF (subtrans.)	~~1,015.00~~1,023.00	SBFT (subtrans.)	~~1,015.00~~1,023.00
IS (primary)	~~622.00~~626.90	IST (primary)	~~622.00~~626.90
IS (subtrans.)	~~2,372.00~~2,390.70	IST (subtrans.)	~~2,372.00~~2,390.70
SBI (primary)	~~647.00~~652.10		
SBI (subtrans.)	~~2,397.00~~2,415.90		

Continued to Sheet No. 8.314

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 7 - SUBSTITUTED

Clean Tariffs

Reflecting Second SoBRA Base Revenue Increase

SUBSTITUTED - 09/24/2018

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

RESIDENTIAL SERVICE

SCHEDULE: RS

AVAILABLE: Entire service area.

APPLICABLE: To residential consumers in individually metered private residences, apartment units, and duplex units. All energy must be for domestic purposes and should not be shared with or sold to others. In addition, energy used in commonly-owned facilities in condominium and cooperative apartment buildings will qualify for this rate schedule, subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owners' benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery will be separately metered and billed.
4. A responsible legal entity is established as the customer to whom the Company can render its bills for said service.

Resale not permitted.

Billing charges shall be prorated for billing periods that are less than 25 days or greater than 35 days. If the billing period exceeds 35 days and the billing extension causes energy consumption, based on average daily usage, to exceed 1,000 kWh, the excess consumption will be charged at the lower monthly Energy and Demand Charge.

LIMITATION OF SERVICE: This schedule includes service to single phase motors rated up to 7.5 HP. Three phase service may be provided where available for motors rated 7.5 HP and over.

MONTHLY RATE:

Basic Service Charge:
$15.12

Energy and Demand Charge:

First 1,000 kWh	5.141¢ per kWh
All additional kWh	6.141¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.031

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTY-FIFTH REVISED SHEET NO. 6.050
CANCELS TWENTY-FOURTH REVISED SHEET NO. 6.050

GENERAL SERVICE - NON DEMAND

SCHEDULE: GS

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted on Schedule GST only.

MONTHLY RATE:

Basic Service Charge:

Metered accounts	$18.14
Un-metered accounts	$15.12

Energy and Demand Charge:
5.412¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.164¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.051

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

GENERAL SERVICE - DEMAND

SCHEDULE: GSD

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

STANDARD		OPTIONAL	
Basic Service Charge:		Basic Service Charge:	
Secondary Metering Voltage	$ 30.24	Secondary Metering Voltage	$ 30.24
Primary Metering Voltage	$ 131.03	Primary Metering Voltage	$ 131.03
Subtrans. Metering Voltage	$ 997.80	Subtrans. Metering Voltage	$ 997.80
Demand Charge:		Demand Charge:	
$10.59 per kW of billing demand		$0.00 per kW of billing demand	
Energy Charge:		Energy Charge:	
1.596¢ per kWh		6.494¢ per kWh	

The customer may select either standard or optional. Once an option is selected, the customer must remain on that option for twelve (12) consecutive months.

Continued to Sheet No. 6.081

Continued from Sheet No. 6.080

BILLING DEMAND: The highest measured 30-minute interval kW demand during the billing period.

MINIMUM CHARGE: The Basic Service Charge and any Minimum Charge associated with optional riders.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW or more in any one billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When a customer under the standard rate takes service at primary voltage, a discount of 86¢ per kW of billing demand will apply. A discount of $2.66 per kW of billing demand will apply when a customer under the standard rate takes service at subtransmission or higher voltage.

Continued to Sheet No. 6.082

TECO TAMPA ELECTRIC AN EMERA COMPANY

NINTH REVISED SHEET NO. 6.082
CANCELS EIGHTH REVISED SHEET NO. 6.082

Continued from Sheet No. 6.081

When a customer under the optional rate takes service at primary voltage, a discount of 0.228¢ per kWh will apply. A discount of 0.695¢ per kWh will apply when a customer under the optional rate takes service at subtransmission or higher voltage.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 68¢ per kW of billing demand for customers taking service under the standard rate and 0.172¢/kWh for customer taking service under the optional rate. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-SECOND REVISED SHEET NO. 6.085
CANCELS TWENTY-FIRST REVISED SHEET NO. 6.085

INTERRUPTIBLE SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: IS

AVAILABLE: Entire Service Area.

APPLICABLE: To be eligible for service under Rate Schedule IS, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Agreement for the Purchase of Industrial Load Management Service under Rate Schedule GSLM-2. When electric service is desired at more than one location, each such location or point of delivery shall be considered as a separate customer. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$ 626.90
Subtransmission Metering Voltage	$2,390.70

Demand Charge:
$3.11 per KW of billing demand

Energy Charge:
2.524¢ per KWH

Continued to Sheet No. 6.086

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTY-FIRST REVISED SHEET NO. 6.086
CANCELS TWENTIETH REVISED SHEET NO. 6.086

Continued from Sheet No. 6.085

BILLING DEMAND: The highest measured 30-minute interval KW demand during the month.

MINIMUM CHARGE: The Basic Service Charge and any Minimum Charge associated with optional riders.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% of the energy and demand charge will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 85¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be $1.22 per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.087

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

CONSTRUCTION SERVICE

SCHEDULE: CS

AVAILABLE: Entire service area.

APPLICABLE: Single phase temporary service used primarily for construction purposes.

LIMITATION OF SERVICE: Service is limited to construction poles and services installed under the TUG program. Construction poles are limited to a maximum of 70 amperes at 240 volts for construction poles. Larger (non-TUG) services and three phase service entrances must be served under the appropriate rate schedule, plus the cost of installing and removing the temporary facilities is required.

MONTHLY RATE:
Basic Service Charge: $18.14

Energy and Demand Charge: 5.412¢ per kWh
.
MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

MISCELLANEOUS: A Temporary Service Charge of $260.00 shall be paid upon application for the recovery of costs associated with providing, installing, and removing the company's temporary service facilities for construction poles. Where the Company is required to provide additional facilities other than a service drop or connection point to the Company's existing distribution system, the customer shall also pay, in advance, for the estimated cost of providing, installing and removing such additional facilities, excluding the cost of any portion of these facilities which will remain as a part of the permanent service.

PAYMENT OF BILLS: See Sheet No. 6.022.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TIME-OF-DAY
GENERAL SERVICE - NON DEMAND
(OPTIONAL)

SCHEDULE: GST

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. All of the electric load requirements on the customer's premises must be metered at one (1) point of delivery. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted.

MONTHLY RATE:

Basic Service Charge:
$20.16

Energy and Demand Charge:
14.963¢ per kWh during peak hours
2.108¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

ISSUED BY: N. G. Tower, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Continued from Sheet No. 6.320

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

MINIMUM CHARGE: The Basic Service Charge.

BASIC SERVICE CHARGE CREDIT: Any customer who makes a one time contribution in aid of construction of $94.00 (lump-sum meter payment), shall receive a credit of $2.02 per month. This contribution in aid of construction will be subject to a partial refund if the customer terminates service on this optional time-of-day rate.

TERMS OF SERVICE: A customer electing this optional rate shall have the right to transfer to the standard applicable rate at any time without additional charge for such transaction, except that any customer who requests this optional rate for the second time on the same premises will be required to sign a contract to remain on this rate for at least one (1) year.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.164¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.322

TWENTY-FIFTH REVISED SHEET NO. 6.330
CANCELS TWENTY-FOURTH REVISED SHEET NO. 6.330

TIME-OF-DAY
GENERAL SERVICE - DEMAND
(OPTIONAL)

SCHEDULE: GSDT

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ 30.24
Primary Metering Voltage	$ 131.03
Subtransmission Metering Voltage	$ 997.80

Demand Charge:
$3.57 per kW of billing demand, plus
$7.02 per kW of peak billing demand

Energy Charge:
2.921¢ per kWh during peak hours
1.054¢ per kWh during off-peak hours

Continued to Sheet No. 6.331

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTY-FIRST REVISED SHEET NO. 6.332
CANCELS TWENTIETH REVISED SHEET NO. 6.332

Continued from Sheet No. 6.331

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage a discount of 86¢ per kW of billing demand will apply. When the customer takes service at subtransmission or higher voltage, a discount of $2.66 per kW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 68¢ per kW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TIME OF DAY
INTERRUPTIBLE SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: IST

AVAILABLE: Entire Service Area.

APPLICABLE: To be eligible for service under Rate Schedule IST, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Agreement for the Purchase of Industrial Load Management Service under Rate Schedule GSLM-2. When electric service is desired at more than one location, each such location or point of delivery shall be considered as a separate customer. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

Basic Service Charge:

Primary Metering Voltage	$ 626.90
Subtransmission Metering Voltage	$2,390.70

Demand Charge:
$3.11 per KW of billing demand

Energy Charge:
2.524¢ per KWH

Continued to Sheet No. 6.345

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTY-SEVENTH REVISED SHEET NO. 6.350
CANCELS TWENTY-SIXTH REVISED SHEET NO. 6.350

Continued from Sheet No. 6.345

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% of the energy and demand charge will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 85¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be $1.22 per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.025.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

TENTH REVISED SHEET NO. 6.565
CANCELS NINTH REVISED SHEET NO. 6.565

Continued from Sheet No. 6.560

MONTHLY RATES:
Basic Service Charge: $15.12

Energy and Demand Charges: 5.455¢ per kWh (for all pricing periods)

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

DETERMINATION OF PRICING PERIODS: Pricing periods are established by season for weekdays and weekends. The pricing periods for price levels P_1 (Low Cost Hours), P_2 (Moderate Cost Hours) and P_3 (High Cost Hours) are as follows:

May through October	P_1	P_2	P_3
Weekdays	11 P.M. to 6 A.M.	6 A.M. to 1 P.M. 6 P.M. to 11 P.M.	1 P.M. to 6 P.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

November through April	P_1	P_2	P_3
Weekdays	11 P.M. to 5 A.M.	5 A.M. to 6 A.M. 10 A.M. to 11 P.M.	6 A.M. to 10 A.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

The pricing periods for price level P_4 (Critical Cost Hours) shall be determined at the sole discretion of the Company. Level P_4 hours shall not exceed 134 hours per year.

Continued to Sheet No. 6.570

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FIFTEENTH REVISED SHEET NO. 6.601
CANCELS FOURTEENTH REVISED SHEET NO. 6.601

Continued from Sheet No. 6.600

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$10.59 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.596¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.602

Continued from Sheet No. 6.602

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of 86¢ per kW of Supplemental Demand and 63¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.66 per kW of Supplemental Demand and $1.97 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 68¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021. Note: Standby fuel charges shall be based on the time of use (i.e., peak and off-peak) fuel rates for Rate Schedule SBF. Supplemental fuel charges shall be based on the standard fuel rate for Rate Schedule SBF.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWELFTH REVISED SHEET NO. 6.606
CANCELS ELEVENTH REVISED SHEET NO. 6.606

Continued from Sheet No. 6.605

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$3.57	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$7.02	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

2.921¢	per Supplemental kWh during peak hours
1.054¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest measured 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Continued to Sheet No. 6.607

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

FOURTEENTH REVISED SHEET NO. 6.608
CANCELS THIRTEENTH REVISED SHEET NO. 6.608

Continued from Sheet No. 6.607

TERM OF SERVICE: Any customer receiving service under this schedule will be required to give the Company written notice at least 60 months prior to transferring to a firm non-standby schedule. Such notice shall be irrevocable unless the Company and the customer should mutually agree to void the notice.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charges, Energy Charges, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charges, Energy Charges, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of 86¢ per kW of Supplemental Demand and 63¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.66 per kW of Supplemental Demand and $1.97 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 68¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.609

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TENTH REVISED SHEET NO. 6.700
CANCELS NINTH REVISED SHEET NO. 6.700

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: SBI

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating customers eligible for service under rate schedules IS or IST whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to self-generating customers eligible for service under rate schedules IS or IST whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. To be eligible for service under this rate schedule, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Supplemental Tariff Agreement for the Purchase of Industrial Standby and Supplemental Load Management Rider Service. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher

LIMITATION OF SERVICE: A customer taking service under this tariff must sign the Tariff Agreement for the Purchase of Standby and Supplemental Service

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$652.10
Subtransmission Metering Voltage	$2,415.90

Demand Charge:

$3.11 per KW-Month of Supplemental Demand (Supplemental Demand Charge)
$1.46 per KW-Month of Standby Demand (Local Facilities Reservation Charge)

plus the greater of:
$1.21 per KW-Month of Standby Demand (Power Supply Reservation Charge); or
$0.48 per KW-Day of Actual Standby Billing Demand (Power Supply Demand Charge)

Continued to Sheet No. 6.705

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

EIGHTH REVISED SHEET NO. 6.715
CANCELS SEVENTH REVISED SHEET NO. 6.715

Continued from Sheet No. 6.710

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% will apply to the standby and supplemental demand charges, energy charges, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charges.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 85¢ per KW of Supplemental Demand and 34¢ per KW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be $1.22 per KW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: Supplemental energy may be billed at either standard or time-of-day fuel rates at the option of the customer. See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

EIGHTH REVISED SHEET NO. 6.805
CANCELS SEVENTH REVISED SHEET NO. 6.805

Continued from Sheet No. 6.800

MONTHLY RATE:

High Pressure Sodium Fixture, Maintenance, and Base Energy Charges:

Rate Code			Lamp Size				Charges per Unit ($)			
					kWh				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
800	860	Cobra[1]	4,000	50	20	10	3.16	2.48	0.55	0.27
802	862	Cobra/Nema[1]	6,300	70	29	14	3.20	2.11	0.79	0.38
803	863	Cobra/Nema[1]	9,500	100	44	22	3.63	2.33	1.20	0.60
804	864	Cobra[1]	16,000	150	66	33	4.18	2.02	1.80	0.90
805	865	Cobra[1]	28,500	250	105	52	4.87	2.60	2.86	1.42
806	866	Cobra[1]	50,000	400	163	81	5.09	2.99	4.45	2.21
468	454	Flood[1]	28,500	250	105	52	5.37	2.60	2.86	1.42
478	484	Flood[1]	50,000	400	163	81	5.71	3.00	4.45	2.21
809	869	Mongoose[1]	50,000	400	163	81	6.50	3.02	4.45	2.21
509	508	Post Top (PT)[1]	4,000	50	20	10	3.98	2.48	0.55	0.27
570	530	Classic PT[1]	9,500	100	44	22	11.85	1.89	1.20	0.60
810	870	Coach PT[1]	6,300	70	29	14	4.71	2.11	0.79	0.38
572	532	Colonial PT[1]	9,500	100	44	22	11.75	1.89	1.20	0.60
573	533	Salem PT[1]	9,500	100	44	22	9.03	1.89	1.20	0.60
550	534	Shoebox[1]	9,500	100	44	22	8.01	1.89	1.20	0.60
566	536	Shoebox[1]	28,500	250	105	52	8.69	3.18	2.86	1.42
552	538	Shoebox[1]	50,000	400	163	81	9.52	2.44	4.45	2.21

(1) Closed to new business
(2) Lumen output may vary by lamp configuration and age.
(3) Wattage ratings do not include ballast losses.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.509¢ per kWh for each fixture.

Continued to Sheet No. 6.806

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

SIXTH REVISED SHEET NO. 6.806
CANCELS FIFTH REVISED SHEET NO. 6.806

Continued from Sheet No. 6.805

MONTHLY RATE:

Metal Halide Fixture, Maintenance, and Base Energy Charges:

Rate Code			Lamp Size				Charges per Unit ($)			
					kWh				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
704	724	Cobra[1]	29,700	350	138	69	7.53	4.99	3.76	1.88
520	522	Cobra[1]	32,000	400	159	79	6.03	4.01	4.34	2.15
705	725	Flood[1]	29,700	350	138	69	8.55	5.04	3.76	1.88
556	541	Flood[1]	32,000	400	159	79	8.36	4.02	4.34	2.15
558	578	Flood[1]	107,800	1,000	383	191	10.50	8.17	10.44	5.21
701	721	General PT[1]	12,000	150	67	34	10.60	3.92	1.83	0.93
574	548	General PT[1]	14,400	175	74	37	10.89	3.73	2.02	1.01
700	720	Salem PT[1]	12,000	150	67	34	9.33	3.92	1.83	0.93
575	568	Salem PT[1]	14,400	175	74	37	9.38	3.74	2.02	1.01
702	722	Shoebox[1]	12,000	150	67	34	7.22	3.92	1.83	0.93
564	549	Shoebox[1]	12,800	175	74	37	7.95	3.70	2.02	1.01
703	723	Shoebox[1]	29,700	350	138	69	9.55	4.93	3.76	1.88
554	540	Shoebox[1]	32,000	400	159	79	10.02	3.97	4.34	2.15
576	577	Shoebox[1]	107,800	1,000	383	191	16.50	8.17	10.44	5.21

(1) Closed to new business
(2) Lumen output may vary by lamp configuration and age.
(3) Wattage ratings do not include ballast losses.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.509¢ per kWh for each fixture.

Continued to Sheet No. 6.808

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SEVENTH REVISED SHEET NO. 6.808
CANCELS SIXTH REVISED SHEET NO. 6.808

Continued from Sheet No. 6.806

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

Rate Code			Size				Charges per Unit ($)			
					kWh(1)				Base Energy(4)	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens(2)	Lamp Wattage(3)	Dusk to Dawn	Timed Svc.	Fixture	Maintenance	Dusk to Dawn	Timed Svc.
828	848	Roadway(1)	5,155	56	20	10	7.27	1.74	0.55	0.27
820	840	Roadway (1)	7,577	103	36	18	11.15	1.19	0.98	0.49
821	841	Roadway(1)	8,300	106	37	19	11.15	1.20	1.01	0.52
829	849	Roadway(1)	15,285	157	55	27	11.10	2.26	1.50	0.74
822	842	Roadway(1)	15,300	196	69	34	14.58	1.26	1.88	0.93
823	843	Roadway(1)	14,831	206	72	36	16.80	1.38	1.96	0.98
835	855	Post Top(1)	5,176	60	21	11	16.53	2.28	0.57	0.30
824	844	Post Top(1)	3,974	67	24	12	19.67	1.54	0.65	0.33
825	845	Post Top(1)	6,030	99	35	17	20.51	1.56	0.95	0.46
836	856	Post Top(1)	7,360	100	35	18	16.70	2.28	0.95	0.49
830	850	Area-Lighter(1)	14,100	152	53	27	14.85	2.51	1.45	0.74
826	846	Area-Lighter(1)	13,620	202	71	35	19.10	1.41	1.94	0.95
827	847	Area-Lighter(1)	21,197	309	108	54	20.60	1.55	2.95	1.47
831	851	Flood(1)	22,122	238	83	42	15.90	3.45	2.26	1.15
832	852	Flood(1)	32,087	359	126	63	19.16	4.10	3.44	1.72
833	853	Mongoose(1)	24,140	245	86	43	14.71	3.04	2.35	1.17
834	854	Mongoose(1)	32,093	328	115	57	16.31	3.60	3.14	1.55

(1) Closed to new business
(2) Average
(3) Average wattage. Actual wattage may vary by up to +/- 5 watts.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.509¢ per kWh for each fixture.

Continued to Sheet No. 6.810

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SECOND REVISED SHEET NO. 6.809
CANCELS FIRST REVISED SHEET NO. 6.809

Continued from Sheet No. 6.808

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

Rate Code			Size				Charges per Unit ($)			
					kWh(1)				Base Energy(3)	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens(1)	Lamp Wattage(2)	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
912	981	Roadway	2,600	27	9	5	4.83	1.74	0.25	0.14
914		Roadway	5,392	47	16		5.97	1.74	0.44	
921		Roadway/Area	8,500	88	31		8.97	1.74	0.85	
926	982	Roadway	12,414	105	37	18	6.83	1.19	1.01	0.49
932		Roadway/Area	15,742	133	47		14.15	1.38	1.28	
935		Area-Lighter	16,113	143	50		11.74	1.41	1.36	
937		Roadway	16,251	145	51		8.61	2.26	1.39	
941	983	Roadway	22,233	182	64	32	11.81	2.51	1.75	0.87
945		Area-Lighter	29,533	247	86		16.07	2.51	2.35	
947	984	Area-Lighter	33,600	330	116	58	20.13	1.55	3.16	1.58
951	985	Flood	23,067	199	70	35	11.12	3.45	1.91	0.95
953	986	Flood	33,113	255	89	45	21.48	4.10	2.43	1.23
956	987	Mongoose	23,563	225	79	39	11.78	3.04	2.15	1.06
958		Mongoose	34,937	333	117		17.84	3.60	3.19	
965		Granville Post Top (PT)	3,024	26	9		5.80	2.28	0.25	
967	988	Granville PT	4,990	39	14	7	13.35	2.28	0.38	0.19
968	989	Granville PT Enh(4)	4,476	39	14	7	15.35	2.28	0.38	0.19
971		Salem PT	5,240	55	19		10.95	1.54	0.52	
972		Granville PT	7,076	60	21		14.62	2.28	0.57	
973		Granville PT Enh(4)	6,347	60	21		16.62	2.28	0.57	
975	990	Salem PT	7,188	76	27	13	13.17	1.54	0.74	.35

(1) Average
(2) Average wattage. Actual wattage may vary by up to +/- 10 %.
(3) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.509¢ per kWh for each fixture.
(4) Enhanced Post Top. Customizable decorative options

Continued to Sheet No. 6.810

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Continued from Sheet No. 6.810

Miscellaneous Facilities Charges:

Rate Code	Description	Monthly Facility Charge	Monthly Maintenance Charge
563	Timer	$7.54	$1.43
569	PT Bracket (accommodates two post top fixtures)	$4.27	$0.06

NON-STANDARD FACILITIES AND SERVICES:

The customer shall pay all costs associated with additional company facilities and services that are not considered standard for providing lighting service, including but not limited to, the following:

1. relays;
2. distribution transformers installed solely for lighting service;
3. protective shields;
4. bird deterrent devices;
5. light trespass shields;
6. light rotations;
7. light pole relocations;
8. devices required by local regulations to control the levels or duration of illumination including associated planning and engineering costs;
9. removal and replacement of pavement required to install underground lighting cable; and
10. directional boring.

MINIMUM CHARGE: The monthly charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021

FRANCHISE FEE: See Sheet No. 6.021

PAYMENT OF BILLS: See Sheet No. 6.022

SPECIAL CONDITIONS:
On customer-owned public street and highway lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 2.509¢ per kWh of metered usage, plus a Basic Service Charge of $10.57 per month and the applicable additional charges as specified on Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.820

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 7.1

Additional Proposed Clean Tariff Sheets

Reflecting the Tampa Electric Tax Reform Docket

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRD REVISED SHEET NO. 6.345
CANCELS SECOND REVISED SHEET NO. 6.345

Continued from Sheet No. 6.340

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

Peak Hours:	April 1 - October 31	November 1 - March 31
(Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING DEMAND: The highest measured 30-minute interval KW demand during the billing period.

MINIMUM CHARGE: The Basic Service Charge and any Minimum Charge associated with optional riders.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

Continued to Sheet No. 6.350

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTEENTH REVISED SHEET NO. 6.600
CANCELS THIRTEENTH REVISED SHEET NO. 6.600

FIRM STANDBY AND SUPPLEMENTAL SERVICE

SCHEDULE: SBF

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ 55.43
Primary Metering Voltage	$ 156.22
Subtransmission Metering Voltage	$1,023.00

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ 1.96 per kW-Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ 1.56 per kW-Month of Standby Demand
(Power Supply Reservation Charge) or

$ 0.62 per kW-Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.921¢ per Standby kWh

Continued to Sheet No. 6.601

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

Continued from Sheet No. 6.601

Contract Standby Demand - As established pursuant to the Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. Anytime a customer registers a Standby Demand that is higher than the existing Contract Standby Demand, that Standby Demand will become the new Contract Standby Demand, beginning with the following period.

Standby Demand - The greater of Contract Standby Demand or the amount by which Metered Demand exceeds Supplemental Billing Demand, but no greater than Normal Generation.

Actual Standby Billing Demand - The summation of the daily amounts by which the highest on-peak measured 30-minute interval kW demands served by the Company exceed the monthly Supplemental Billing Demand.

Energy Units: Energy provided by the Company during each 30-minute period up to the Supplemental Demand level shall be billed as Supplemental kWh. The remaining energy shall be billed as Standby kWh.

MINIMUM CHARGE: The Basic Service Charge, Local Facilities Reservation Charge, Power Supply Reservation Charge, and any Minimum Charge associated with optional riders.

TERM OF SERVICE: Any customer receiving service under this schedule will be required to give the Company written notice at least 60 months prior to transferring to a firm non-standby schedule. Such notice shall be irrevocable unless the Company and the customer should mutually agree to void the notice.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

Continued to Sheet No. 6.603

TIME-OF-DAY
FIRM STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

SCHEDULE: SBFT

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ 55.43
Primary Metering Voltage	$ 156.22
Subtransmission Metering Voltage	$1,023.00

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ 1.96 per kW-Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ 1.56 per kW-Month of Standby Demand
(Power Supply Reservation Charge) or

$ 0.62 per kW-Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.921¢ per Standby kWh

Continued to Sheet No. 6.606

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FIFTH REVISED SHEET NO. 6.705
CANCELS FOURTH REVISED SHEET NO. 6.705

Continued from Sheet No. 6.700

Energy Charge:
2.524¢ per Supplemental KWH
1.014¢ per Standby KWH

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval KW demand served by the company during the month.

Site Load - The highest KW total of Customer generation plus deliveries by the Company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.710

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TENTH REVISED SHEET NO. 8.070
CANCELS NINTH REVISED SHEET NO. 8.070

Continued from Sheet No. 8.061

CHARGES/CREDITS TO QUALIFYING FACILITY

A. Basic Service Charges

A monthly Basic Service Charge will be rendered for maintaining an account for a Qualifying Facility engaged in either an As-Available Energy or Firm Capacity and Energy transaction and for other applicable administrative costs. Actual charges will depend on how the QF is interconnected to the Company.

QFs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

Monthly Basic Service charges, applicable to QFs directly interconnected to the Company, by Rate Schedule are:

Rate Schedule	Basic Service Charge ($)	Rate Schedule	Basic Service Charge ($)
RS	15.12	GST	20.16
GS	18.14	GSDT (secondary)	30.24
GSD (secondary)	30.24	GSDT (primary)	131.03
GSD (primary)	131.03	GSDT (subtrans.)	997.80
GSD (subtrans.)	997.80	SBFT (secondary)	55.43
SBF (secondary)	55.43	SBFT (primary)	156.22
SBF (primary)	156.22	SBFT (subtrans.)	1,023.00
SBF (subtrans.)	1,023.00	IST (primary)	626.90
IS (primary)	626.90	IST (subtrans.)	2,390.70
IS (subtrans.)	2,390.70		
SBI (primary)	652.10		
SBI (subtrans.)	2415.90		

When appropriate, the Basic Service Charge will be deducted from the Qualifying Facility's monthly payment. A statement of the charges or payments due the Qualifying Facility will be rendered monthly. Payment normally will be made by the twentieth business day following the end of the billing period.

Continued to Sheet No. 8.071

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

THIRD REVISED SHEET NO. 8.312
CANCELS SECOND REVISED SHEET NO. 8.312

Continued from Sheet No. 8.308

Should the CEP elect a Net Billing Arrangement, the hourly net capacity and energy sales delivered to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C. Purchases from the interconnecting utility shall be billed at the retail rate schedule, under which the CEP load would receive service as a customer of the utility.

Although a billing option may be changed in accordance with FPSC Rule 25-17.082, F.A.C., the Contracted Capacity may only change through mutual negotiations satisfactory to the CEP and the Company.

Basic Service charges that are directly attributable to the purchase of firm capacity and energy from the CEP are deducted from the CEP's total monthly payment. A statement covering the charges and payments due the CEP is rendered monthly and payment normally is made by the 20th business day following the end of the Monthly Period.

CHARGES/CREDITS TO THE CEP:

1. **Basic Service Charges:** A monthly Basic Service Charge will be rendered for maintaining an account for the CEP engaged in either an As-Available Energy or firm capacity and energy transaction and for other applicable administrative costs. Actual charges will depend on how the CEP is interconnected to the Company.

   CEPs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

   Monthly Basic Service charges, applicable to CEPs directly interconnected to the Company, by Rate Schedule are:

RATE SCHEDULE	BASIC SERVICE CHARGE ($)	RATE SCHEDULE	BASIC SERVICE CHARGE ($)
RS	15.12		
GS	18.14	GST	20.16
GSD (secondary)	30.24	GSDT (secondary)	30.24
GSD (primary)	131.03	GSDT (primary)	131.03
GSD (subtrans.)	997.80	GSDT (subtrans.)	997.80
SBF (secondary)	55.43	SBFT (secondary)	55.43
SBF (primary)	156.22	SBFT (primary)	156.22
SBF (subtrans.)	1,023.00	SBFT (subtrans.)	1,023.00
IS (primary)	626.90	IST (primary)	626.90
IS (subtrans.)	2,390.70	IST (subtrans.)	2,390.70
SBI (primary)	652.10		
SBI (subtrans.)	2,415.90		

Continued to Sheet No. 8.314

5

Staff's First Data Request Nos. 1 – 28

Supplemental Response to No. 23

(See additional files contained on Staff Hearing Exhibit CD/USB for 1, 10, 11, 15-17, and 19.)

Confidential DN. 05029-2018

(No. 26)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180133-EI EXHIBIT: 5
PARTY: STAFF – (DIRECT)
DESCRIPTION: James Rocha1, 10-17, 23-28Mark Ward2-9, 13, 18, 20-22William

[3] Document No. 04746-2018, filed on July 18, 2018, in Docket No. 20180133-EI.

For the purpose of this question and sub-parts, please refer to the Direct Testimony and Exhibits of R. James Rocha, on behalf of Tampa Electric Company, as filed on June 29, 2018.

1. Page 12, Line 11 and Document Number 3 of Exhibit RJR-1 reflect \$46,045,000 as the amount of revenue requirements for the Second SoBRA with Sharing Mechanism. Please provide worksheets and/or schedules with formulas intact to demonstrate how:

A. The Capital RR and FOM amounts (\$11,205,000, and \$547,000, respectively) were calculated for Lithia.

B. The Capital RR and FOM amounts (\$9,223,000, and \$448,000, respectively) were calculated for Grange Hall.

C. The Capital RR and FOM amounts for (\$8,155,000, and \$407,000, respectively) were calculated for Peace Creek.

D. The Capital RR and FOM amounts (\$5,848,000, and \$275,000, respectively) were calculated for Bonnie Mine.

E. The Capital RR and FOM amounts (\$4,786,000, and \$233,000, respectively) were calculated for Lake Hancock.

F. The Land RR (\$4,917,000) was calculated.

A. See the Excel file "20180133 Staff's 1st Data Request.xlsx" on tab "Q1" for responses to subsections (A) through (F).

A. See cells D45 and D47.

B. See cells H45 and H47.

C. See cells L45 and L47.

D. See cells P45 and P47.

E. See cells T45 and T47.

F. See the addition of cells D52, H52, L52, P52 and T52.

For the purpose of this question and sub-parts, please refer to the Direct Testimony and Exhibits of Mark D. Ward, on behalf of Tampa Electric Company, as filed on June 29, 2018.

2. Page 15, Line 8 through Page 16, Line 6. Please answer the following.

A. The witness asserts that recent steel tariffs could have a monetary impact of $20 to $30 per kilowatt-hour alternating current (kWac), and this will affect the project costs for Peace Creek. Does the estimated cost of $1,492/kWac for Peace Creek reflect the added cost of the steel tariffs? Please explain your response.

B. The witness asserts that recent steel tariffs could have a monetary impact of $20 to $30 per kilowatt-hour alternating current (kWac), and this will affect the project costs for Bonnie Mine. Does the estimated cost of $1,464/kWac for Bonnie Mine reflect the added cost of the steel tariffs? Please explain your response.

C. The witness asserts that recent steel tariffs could have a monetary impact of $20 to $30 per kilowatt-hour alternating current (kWac), and this will affect the project costs for Lake Hancock. Does the estimated cost of $1,494/kWac for Lake Hancock reflect the added cost of the steel tariffs? Please explain your response.

D. When will the Company be able to quantify the monetary impact of steel tariffs that could have the Peace Creek, Bonnie Mine, and Lake Hancock project costs?

A. A. The Peace Creek Solar project cost includes the impact of the steel import tariffs. The developer and Tampa Electric minimized cost increases by ordering steel equipment and material in advance. The Peace Creek Solar cost includes an estimate of $500k for steel tariffs.

B. The Bonnie Mine Solar project includes the impact of the steel import tariffs. The developer and Tampa Electric minimized cost increases by ordering steel equipment and material in advance. The Bonnie Mine Solar cost includes an estimate of $750k for steel tariffs.

C. The Lake Hancock Solar project cost includes the impact of the steel import tariffs. The developer and Tampa Electric minimized cost increases by ordering steel equipment and material in advance. The Lake Hancock cost includes an estimate of $750k for steel tariffs.

D. See the response to parts (A) through (C). Equipment containing significant amounts of steel (trackers and racking systems) and steel material (posts) will be delivered and fully invoiced in the fourth quarter of 2018. Tampa Electric can then determine the impacts of the tariffs with greater precision.

For the purpose of questions 3-7 and sub-parts, please refer to Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, on behalf of Tampa Electric Company, as filed on June 29, 2018.

3. Please answer the following questions regarding the Lithia property:

A. How many total acres are in the Lithia property?

B. How many acres in the Lithia property are planned for this solar installation?

C. How many acres in the Lithia property would be suitable for future development as a solar installation, or for other utility purposes?

D. How many acres in the Lithia property are not suitable for a solar installation, or for any other utility purpose?

E. How long has Tampa Electric Company owned the Lithia property?

F. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $2.4 million is planned for development of the Lithia property. Please describe the work activities that are needed to develop the Lithia property.

G. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $4 million is planned for developing the transmission interconnection for the Lithia property. Please describe the work needed to develop the transmission interconnection for the Lithia property.

H. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $900,000 is planned for owner costs for the Lithia property. Please describe the costs, citing examples.

A. A. The Lithia Solar project site is 596 acres.

B. The Lithia solar array will be on 438 acres.

C. Approximately 137 acres may be available for a future cost-effective battery storage project to be integrated with the solar project.

D. Approximately 21 acres are not compatible for PV solar or other utility purposes. This land has been identified as wetlands and will not be mitigated for any other use.

E. The site includes parcels purchased from 10 different owners. The first nine parcels were purchased February 13-15, 2018. The last parcel was purchased March 30, 2018.

F. The work activities necessary to develop the Lithia Solar site include developer due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include detailed geotechnical studies, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array. Additional development work includes demolition of existing structures on the property and clearing and removing roots and stumps from the former orange groves.

G. The transmission interconnection required for Lithia Solar includes constructing a new 3-position 230-kV ring bus switchyard and loop into an existing 230-kV transmission line.

H. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects and were not employed prior to Tampa Electric's last rate case, as well as consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

The owner's costs also include site due diligence (preliminary geotechnical study and environmental studies), surveys, real estate due diligence, legal costs, wet lands delineation, the permitting and relocation of a large number of gopher tortoises, builder's risk insurance, engineering and management of the environmental permitting process.

4. Please answer the following questions regarding the Grange Hall property:

A. How many total acres are in the Grange Hall property?

B. How many acres in the Grange Hall property are planned for this solar installation?

C. How many acres in the Grange Hall property would be suitable for future development as a solar installation, or for other utility purposes?

D. How many acres in the Grange Hall property are not suitable for a solar installation, or for any other utility purpose?

E. How long has Tampa Electric Company owned the Grange Hall property?

F. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $1.8 million is planned for development of the Grange Hall property. Please describe the work activities that are needed to develop this property.

G. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $4.6 million is planned for developing the transmission interconnection for the Grange Hall property. Please describe the work needed to develop the transmission interconnection for this property.

H. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $500,000 is planned for owner costs for the Grange Hall property. Please describe the costs, citing examples.

A. A. The Grange Hall Solar project is 445 acres.

B. The Grange Hall solar array will be on 247 acres.

C. Approximately 10 acres may be available for a future cost-effective battery storage project to be integrated with the solar project.

D. Approximately 188 acres are not compatible for PV solar or other utility purposes. This land has been identified as wetlands and will not be mitigated for any other use.

E. The Grange Hall Solar site was purchased June 28, 2017.

F. The work activities necessary to develop the Grange Hall Solar site include developer due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include detailed geotechnical studies, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array.

G. The transmission interconnection required for Grange Hall Solar facility includes constructing 4.75 miles of a 69-kV transmission radial line from the Grange Hall substation to interconnect the planned facility. In addition, there is estimated to be a need to upgrade relays at the existing Tampa Electric Mines Substation.

H. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects and were not employed prior to Tampa Electric's last rate case, as well as consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

The owner's costs also include site due diligence (preliminary geotechnical study and environmental studies), surveys, real estate due diligence, legal costs, wet lands delineation, builders risk insurance, engineering and management of the environmental permitting process.

5. Please answer the following questions regarding the Peace Creek property:

A. How many total acres are in the Peace Creek property?

B. How many acres in the Peace Creek property are planned for this solar installation?

C. How many acres in the Peace Creek property would be suitable for future development as a solar installation, or for other utility purposes?

D. How many acres in the Peace Creek property are not suitable for a solar installation, or for any other utility purpose?

E. How long has Tampa Electric Company owned the Peace Creek property?

F. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $1.8 million is planned for development of the Peace Creek property. Please describe the work activities that are needed to develop this property.

G. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $4.7 million is planned for developing the transmission interconnection for the Peace Creek property. Please describe the work needed to develop the transmission interconnection for this property.

H. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $400,000 is planned for owner costs for the Peace Creek property. Please describe the costs, citing examples.

A. A. The Peace Creek Solar project site is 416 acres.

B. The Peace Creek Solar array will be on 228 acres.

C. Approximately 5 acres may be available for a future cost-effective battery storage project to be integrated with the solar project.

D. Approximately 183 acres are not compatible for PV solar or other utility purposes. This land has been identified as wetlands and will not be mitigated for any other use.

E. The Peace Creek project site was purchased February 23, 2018.

F. The work activities necessary to develop the Peace Creek Solar site include developer due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include detailed geotechnical studies, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array.

G. The transmission interconnection required for the Peace Creek Solar facility includes constructing 2.78 miles of a 69-kV transmission radial line tap from the Peace Creek substation to interconnect the planned facility. This construction will include two new line switches and an upgrade to another line switch.

H. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects and were not employed prior to Tampa Electric's last rate case, as well as consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

The owner's costs also include site due diligence (preliminary geotechnical study and environmental studies), surveys, real estate due diligence, legal costs, wet lands delineation, builders risk insurance, engineering and management of required the environmental permitting process.

6. Please answer the following questions regarding the Bonnie Mine property:

A. How many total acres are in the Bonnie Mine property?

B. How many acres in the Bonnie Mine property are planned for this solar installation?

C. How many acres in the Bonnie Mine property would be suitable for future development as a solar installation, or for other utility purposes?

D. How many acres in the Bonnie Mine property are not suitable for a solar installation, or for any other utility purpose?

E. How long has Tampa Electric Company owned the Bonnie Mine property?

F. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $1.4 million is planned for development of the Bonnie Mine property. Please describe the work activities that are needed to develop this property.

G. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $900,000 is planned for developing the transmission interconnection for the Bonnie Mine property. Please describe the work needed to develop the transmission interconnection for this property.

H. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $300,000 is planned for owner costs for the Bonnie Mine property. Please describe the costs, citing examples.

A. A. The Bonnie Mine Solar project site is 352 acres.

B. The Bonnie Mine Solar array will be on 283 acres.

C. There will be no acreage available for a future cost-effective battery storage project to be integrated with the solar project.

D. Approximately 69 acres are not compatible for PV solar or other utility purposes. This land has been identified as wetlands and will not be mitigated for any other use.

E. The Bonnie Mine Solar project site was purchased April 28, 2018.

F. The work activities necessary to develop the Peace Creek Solar site include developer due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include detailed geotechnical studies, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array.

G. The transmission interconnection required for the Bonnie Mine Solar facility includes constructing 0.1 miles of a 69-kV transmission radial line tap from the Bonnie Mine substation to interconnect the planned facility. This construction will include two new line switches.

H. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects and were not employed prior to Tampa Electric's last rate case, as well as consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

The owner's costs also include site due diligence (preliminary geotechnical study and environmental studies), surveys, real estate due diligence, legal costs, wet lands delineation, builders risk insurance, engineering and management of the environmental permitting process.

7. Please answer the following questions regarding the Lake Hancock property:

A. How many total acres are in the Lake Hancock property?

B. How many acres in the Lake Hancock property are planned for this solar installation?

C. How many acres in the Lake Hancock property would be suitable for future development as a solar installation, or for other utility purposes?

D. How many acres in the Lake Hancock property are not suitable for a solar installation, or for any other utility purpose?

E. How long has Tampa Electric Company owned the Lake Hancock property?

F. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $1.6 million is planned for development of the Lake Hancock property. Please describe the work activities that are needed to develop this property.

G. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $4.1 million is planned for developing the transmission interconnection for the Lake Hancock property. Please describe the work needed to develop the transmission interconnection for this property.

H. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $300,000 is planned for owner costs for the Lake Hancock property. Please describe the costs, citing examples.

A. A. The Lake Hancock Solar project site is 358 acres.

B. The Lake Hancock Solar array will be on 230 acres.

C. There are approximately 124 acres available for a future cost-effective battery storage project to be integrated with the solar project.

D. Approximately 4 acres are not compatible for PV solar or other utility purposes. This land has been identified as wetlands and will not be mitigated for any other use.

E. The Lake Hancock Solar project site was purchased June 29, 2018.

F. The work activities necessary to develop the Lake Hancock Solar site include developer due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include detailed geotechnical studies, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array.

G. The transmission interconnection required for the Lake Hancock Solar facility includes constructing 1.35 miles of a 69-kV transmission radial line tap from the Lake Hancock substation to the 69-kV circuit between Sandhill and Crews Lake Substations. It is estimated that both the Sandhill and Crews Lakes Substations will require relay upgrades as a result of the interconnection of this planned facility.

H. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects and were not employed prior to Tampa Electric's last rate case, as well as consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

The owner's costs also include site due diligence (preliminary geotechnical study and environmental studies), surveys, real estate due diligence, legal costs, wet lands delineation, builders risk insurance, engineering and management of the environmental permitting process.

8. **Land.** Please refer to Page 13, Lines 10 – 20 , of the direct testimony of witness Ward. Please explain how existing sites were chosen as suitable for solar development.

A. Tampa Electric's land screening process includes evaluating each site for constructability, environmental compatibility, transmission access, acreage to support the solar project and land use compatibility. Tampa Electric has a land team that includes subject matter experts in renewable energy, real estate, environmental, legal and transmission planning.

When the land team identifies a potential site, it enters into an agreement with the land-owner that includes a price for the land and allows for a period of time for Tampa Electric's land team and developer to conduct site due diligence. The due diligence process includes but is not limited to geotechnical studies, environmental studies, cultural resource assessments, transmission interconnection cost estimates, indicative size and performance of the solar array, and cost estimates for the construction of solar project. An indicative all-in-cost is developed for the site, and that cost is evaluated for cost-effectiveness.

If the project site shows no environmental or constructability issues and the indicative cost and performance show the project is cost-effective, then Tampa Electric exercises its option to purchase the site.

9. **Cost Effectiveness.** Please refer to EXH MDW-1. Explain what transmission upgrades are necessary for completing each 2019 SoBRA Project and all associated costs. Provide this in electronic (Excel) format.

A. Preliminary estimates of the costs to interconnect and potential upgrades necessary are described for each project in the above responses to Data Requests 4(G) through 7(G). Additional transmission network upgrades may be required as identified through the pending System Impact and Facilities studies that have not yet been completed.

10. **Resource Planning.** Please refer to EXH RJR-1. Provide the reserve margin in percentage of net firm system peak for the years 2019 to 2048 (30-year period) in an Excel table comparing the reserve margin with only the 2018 Solar Tranche versus the reserve margin with the 2018 and 2019 Solar Tranches.

A. See the following table, which is also provided in Excel file "20180133 Staff's 1st Data Request.xlsx" on tab "Q10".

	Reference w/ Tranche 1	Reference w/ Tranche 1 & 2	
Year	Reserve Margin (W/S %)	Reserve Margin (W/S %)	RM Delta (W/S %)
2018	34%	34%	0.0%
	24%	24%	0.0%
2019	22%	22%	0.0%
	21%	24%	3.4%
2020	20%	20%	0.0%
	23%	23%	0.2%
2021	20%	20%	0.0%
	22%	22%	0.2%
2022	20%	20%	0.0%
	20%	20%	0.2%
2023	24%	24%	0.0%
	27%	27%	0.0%
2024	22%	22%	0.0%
	26%	26%	0.0%
2025	20%	20%	0.0%
	24%	24%	0.0%
2026	24%	24%	0.0%
	28%	28%	0.0%
2027	22%	22%	0.0%
	26%	26%	0.0%
2028	21%	21%	0.0%
	25%	25%	0.0%

	Reference w/ Tranche 1	Reference w/ Tranche 1 & 2	
Year	Reserve Margin (W/S %)	Reserve Margin (W/S %)	RM Delta (W/S %)
2029	24%	24%	0.0%
	28%	28%	0.0%
2030	23%	23%	0.0%
	27%	27%	0.0%
2031	22%	22%	0.0%
	25%	25%	0.0%
2032	20%	20%	0.0%
	24%	24%	0.0%
2033	24%	24%	0.0%
	28%	28%	0.0%
2034	23%	23%	0.0%
	26%	26%	0.0%
2035	21%	21%	0.0%
	25%	25%	0.0%
2036	20%	20%	0.0%
	24%	24%	0.0%
2037	24%	24%	0.0%
	27%	27%	0.0%
2038	24%	24%	0.0%
	27%	27%	0.0%
2039	24%	24%	0.0%
	27%	27%	0.0%
2040	24%	24%	0.0%
	27%	27%	0.0%
2041	24%	24%	0.0%
	24%	24%	0.0%
2042	23%	23%	0.0%
	24%	24%	0.0%
2043	23%	23%	0.0%
	32%	32%	0.0%
2044	20%	20%	0.0%
	23%	23%	0.0%

	Reference w/ Tranche 1	Reference w/ Tranche 1 & 2	
Year	Reserve Margin (W/S %)	Reserve Margin (W/S %)	RM Delta (W/S %)
2045	20%	20%	0.0%
	23%	23%	0.0%
2046	20%	20%	0.0%
	23%	23%	0.0%
2047	20%	20%	0.0%
	23%	23%	0.0%
2048	20%	20%	0.0%
	23%	23%	0.0%

11. **Resource Planning.** Please complete the table below based on your most recent planning for the life of the proposed solar tranche from 2019 to 2048 (30-year life) and provide in electronic format.

Year	Installed Capacity (MW)	Firm Import Capacity (MW)	Firm Export Capacity (MW)	QF Capacity (MW)	Total Available Capacity (MW)	System Firm Summer Peak Demand (MW)	Reserve Margin Before Maintenance (MW)	Scheduled Maintenance (MW)	Reserve Margin After Maintenance (MW)

A. The requested information is provided in the Excel file titled "20180133 Staff's 1st Data Request.xlsx" on tab "Q11".

12. **Resource Planning.** Please refer to EXH RJR-1. Provide a table comparing TECO's resource plan with the 2019 Solar Tranche included and with the 2019 Solar Tranche excluded.

A. The following table describes the reference case with the 2019 Solar Tranche excluded.

Reference w/ Tranche 1

Year	Portfolio Additions	Portfolio Retirement	Reserve Margin Winter and Summer %
2018	Solar 144.7 MW - S	–	34% 24%
2019	–	–	22% 21%
2020	PPA Placeholder 50 MW - S	–	20% 23%
2021	(2) 7HA.02 CT (Converted to CC 2023) 393/360 MW - S PPA Placeholder 50/100 MW - W/S	BB 1 Repower Feb 2021 BB 2 Retires June 2021	20% 22%
2022	PPA Placeholder 100/150 MW - W/s	–	20% 20%
2023	(1) GE 7FA.05 CT 245/229 MW - W (1) 2x1 CC (remaining portion) 335 MW - W	–	24% 27%
2024	–	–	22% 26%
2025	–	–	20% 24%
2026	(1) GE 7FA.05 CT 245/229 MW - W	–	24% 28%

Reference w/ Tranche 1

Year	Portfolio Additions	Portfolio Retirement	Reserve Margin Winter and Summer %
2027	–	–	22%
			26%
2028	–	–	21%
			25%
2029	(1) GE 7FA.05 CT 245/229 MW - W	–	24%
			28%
2030	–	–	23%
			27%
2031	–	–	22%
			25%
2032	–	–	20%
			24%
2033	(1) GE 7FA.05 CT 245/229 MW - W	–	24%
			28%
2034	–	–	23%
			26%
2035	–	–	21%
			25%
2036	–	PK 1 Retires Sep 2036	20%
			24%
2037	(2) GE 7FA.05 CT 489/459 MW - W	–	24%
			27%
2038	–	–	24%
			27%
2039	–	–	24%
			27%
2040	–	–	24%
			27%

Reference w/ Tranche 1

Year	Portfolio Additions	Portfolio Retirement	Reserve Margin Winter and Summer %
2041	–	BB 3 Retires May 2041	24%
			24%
2042	–	–	23%
			24%
2043	(1) GE 2x1 7HA.02 CC 1128/1064 MW - S	BAY 1 Retires Apr 2043	23%
			32%
2044	(1) GE LM-2500 37/30 MW - W (1) GE 1x1 7HA.02 CC 506/479 MW - W	BAY 2 Retires Jan 2044	20%
			23%
2045	–	–	20%
			23%
2046	–	–	20%
			23%
2047	–	–	20%
			23%

The following table describes the reference case plus 278 MW of solar generation.

Reference w/ Tranche 1 & 2

Year	Portfolio Additions	Portfolio Retirement	Reserve Margin Winter and Summer %
2018	Solar 144.7 MW - S	–	34% 24%
2019	Solar 278 MW - W	–	22% 24%
2020	–	–	20% 23%
2021	(2) 7HA.02 CT (Converted to CC 2023) 393/360 MW - S PPA Placeholder 50 MW - W	BB 1 Repower Feb 2021 BB 2 Retires June 2021	20% 22%
2022	PPA Placeholder 100 MW - W	–	20% 20%
2023	(1) GE 7FA.05 CT 245/229 MW - W (1) 2x1 CC (remaining portion) 335 MW - W	–	24% 27%
2024	–	–	22% 26%
2025	–	–	20% 24%
2026	(1) GE 7FA.05 CT 245/229 MW - W	–	24% 28%
2027	–	–	22% 26%
2028	–	–	21% 25%
2029	(1) GE 7FA.05 CT 245/229 MW - W	–	24% 28%
2030	–	–	23%

Reference w/ Tranche 1 & 2

Year	Portfolio Additions	Portfolio Retirement	Reserve Margin Winter and Summer %
			27%
2031	–	–	22%
			25%
2032	–	–	20%
			24%
2033	(1) GE 7FA.05 CT 245/229 MW - W	–	24%
			28%
2034	–	–	23%
			26%
2035	–	–	21%
			25%
2036	–	PK 1 Retires Sep 2036	20%
			24%
2037	(2) GE 7FA.05 CT 489/459 MW - W	–	24%
			27%
2038	–	–	24%
			27%
2039	–	–	24%
			27%
2040	–	–	24%
			27%
2041	–	BB 3 Retires May 2041	24%
			24%
2042	–	–	23%
			24%
2043	(1) GE 2x1 7HA.02 CC 1128/1064 MW - S	BAY 1 Retires Apr 2043	23%
			32%
2044			20%

Reference w/ Tranche 1 & 2

Year	Portfolio Additions	Portfolio Retirement	Reserve Margin Winter and Summer %
	(1) GE LM-2500 37/30 MW - W (1) GE 1x1 7HA.02 CC 506/479 MW - W	BAY 2 Retires Jan 2044	23%
2045	–	–	20% 23%
2046	–	–	20% 23%
2047	–	–	20% 23%

13. **Cost Effectiveness.** Please refer to Page 19, Lines 15 – 23, of the direct testimony of witness Ward. Provide a comparison of the 2019 Solar Plan to customer-owned residential rooftop installations with an equivalent installed capacity. Please assume a residential customer installs 5kW rooftop systems at each residence. Include any assumptions and how these assumptions were made.

A. Utility-scale solar makes cost-effective solar energy more available to all Tampa Electric customers regardless of roof condition, orientation, shade, or ownership. It allows customers to benefit from solar energy systems with no upfront out-of-pocket costs or financing fees, no long-term commitment and no maintenance or rooftop intrusion. With utility-scale solar, customers benefit from lower capital costs, due to economies of scale, and higher capacity factors, due to the ability to track the sun.

Page 19 of the direct testimony of witness Ward refers to the 2019 Solar Plan to build five single axis tracking solar PV projects with the total capacity of 278 MWac. The anticipated installed cost for each project ranges from $1,438/kWac to $1,494/kWac. Based on information gathered by local solar installers (and in line with what has been reported by the National Renewable Energy Laboratory), a 5 kWac residential rooftop system would cost on average about $2,805/kWac, almost twice the cost of utility-scale solar projects.

To achieve 278 MWac of rooftop solar capacity would require installing 5 kWac PV systems on 55,600 residential rooftops. To achieve the amount of energy that 278 MWac of utility-scale solar will produce, that number increases to 81,856 homes. This assumes the average capacity factor of 26.5% for utility-scale solar, which equates to 645,349 MWh/year. The average 5 kWac rooftop system with a capacity factor of 18% will produce approximately 7.9 MWh/year.

14. **Cost Effectiveness.** For all planned solar generation, please detail the depreciation life and actual life of each individual unit.

A. The company uses a thirty-year book life, with straight line depreciation for tracking photovoltaic solar facilities. This 30-year book life was selected because it is expected to be the actual life of the unit. All of the planned solar generation is tracking PV.

For tax depreciation, the federal Modified Accelerated Cost Recovery System ("MACRS"), establishes a set of class lives for various types of properties. Among the classes is solar energy to generate electricity which is denoted as a 5-year MACRS.

15. **Cost Effectiveness.** Please refer to EXH RJR-1, Document No. 5. For all planned solar generation, please provide the annual and cumulative values over a 30-year period (in nominal and net present value) for each of the following categories: Equipment and Installation, Incremental Fixed O&M, Fuel Savings, Emissions Savings, separated by type (CO2, etc.), Avoided Replacement Costs, Avoided Capacity Purchases, Avoided Fixed O&M, Avoided Variable O&M and Transmission Upgrades. Please provide this response in electronic (Excel) format.

a. Please explain in detail the assumptions, facts, and figures used to determine the value of each of the components evaluated in this analysis.

b. Please explain whether TECO's emissions savings include CO2 or CO2 equivalent emissions. If so, please provide a sensitivity of the analysis without these costs and provide the revised annual and cumulative values (in nominal and net present value) for each category in electronic (Excel) format.

c. Please explain whether TECO reviewed the cost-effectiveness of the generation upgrades using fuel price sensitivities. As part of this response, please provide a sensitivity of the fuel savings based upon a low fuel price forecast and a high fuel price forecast, with revised annual and cumulative values (in nominal and net present value) for each category in electronic (Excel) format.

A. The requested information is provided in the Excel file titled "20180133 Staff's 1st Data Reqest.xlsx" on tab "Q15". There are no avoided capacity purchases. Avoided replacement power costs are already included in the system fuel line. Avoided variable O&M is provided in the System VOM line. Transmission upgrade information is provided in the company's response to Data Request Nos. 3(g), 4(g), 5(g), 6(g), 7(g) and 9.

a. Detailed cost analyses are performed using System Optimizer and Planning & Risk (PaR) production costs models, developed by ABB. The capital and fixed expenditures are based on a compilation of technology costs from a third-party vendor. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch combined with the fixed charges to obtain the annual and total present values.

b. The Second SoBRA produces cost savings of \$14.2 million, not including any emissions savings. NO_X and CO_2 emission reductions produce an additional \$24.8 million of savings for a total customer savings of \$39.0 million. See the Excel file provided for the annual and cumulative values of NO_X and CO_2 emission savings.

c. Yes, as stated in the prepared direct testimony of Tampa Electric witness Rocha on page 21, lines 9-13, the company reviewed the cost-effectiveness of the second tranche of solar generation using high and low fuel price sensitivities. The results of these sensitivities confirmed that customer savings would occur under the high fuel forecast.

The fuel forecast sensitivities used in the CPVRR analysis for the Second SoBRA are from the same fuel forecast used in preparing the 2019 projected costs and cost recovery factors to be submitted on August 24, 2018 in Docket No. 20180001-EI. The high and low fuel forecasts are shown in the company's response to the Staff's First Request for Production of Documents, No. 5.

See the Excel file provided, tabs "Q15c – High Fuel" and "Q15c – Low Fuel", for the annual and cumulative values for the high fuel and low fuel sensitivities.

16. **Cost Effectiveness.** Please refer to EXH RJR-1, Document No. 5. Provide the avoided fossil fuels (avoided oil barrels, avoided natural gas MMcf, avoided coal short tons) from the years 2019 to 2048 (30-year period). Please explain how calculations were made for each fuel and provide an example using 2020. Provide the response in tabular electronic format in Excel.

A. The production cost modeling performed for this analysis included 30 years of fuel and purchased power representing the period 2018 through 2047.

A base case model was prepared without the second tranche of solar generation. Next, starting from this base case, a change case model was prepared, and the base case and change case were run with the production cost modeling software for an economic dispatch. The generation times the heat rate divided by the fuel's heating value equals the fuel used. The change case fuels were then subtracted from the base case fuels to arrive at the avoided fuels.

The Excel file titled "20180133 Staff's 1st Data Reqest.xlsx" provides the avoided fossil fuels and example calculations for year 2020 on tabs "Q16", "Q16 – Coal Tons", "Q16 – NG MCF", and "Q16 – PetCoke Tons". Also see the company's response to Staff's 1st Request for Production of Documents, No. 5, for the base case and change case fuels.

17. **Cost Effectiveness**. Please refer to Page 22, Lines 4– 9, of the direct testimony of witness Ward. Provide the avoided air emissions (CO2, SO2, NOx) for the 30-year period. Show how each was calculated using the year 2020 as an example. Please provide the response in tabular electronic format in Excel.

A. Page 22, Lines 4–9, of the direct testimony of witness Rocha refers to avoided air emissions. The production cost modeling performed for this analysis included 30 years of fuel and purchased power representing the period of 2018 through 2046.

A base case model was prepared without the second tranche of solar generation. Next, starting from this base case, a change case model was prepared with the second tranche, 278 MW of solar generation in service on January 1, 2019. Both the base case and change case were run with the production cost modeling software for an economic dispatch. The fuel used times the fuel's emissions rate equals the emissions. The change case emissions were then subtracted from the base case emissions to arrive at the avoided emissions.

The Excel file titled "20180133 Staff's 1st Data Request.xlsx" provides the air emissions and example calculations for year 2020 on tabs "Q17", "Q17 – Avoided CO_2", "Q17 – Avoided NO_X", and "Q17 – Avoided SO_2".

18. **Resource Planning.** Please refer to Schedule 8.1 of TECO's 2018 Ten-Year Site Plan, provided in response to POD No. 1, and EXH MDW-1, Document No. 1, Page 1 of 3 to the direct testimony of witness Ward. Why was the in-service date of the Lake Hancock Solar Project changed from January 2021 to January 2019? If this change is related to the status of the Mountain View Solar Project, please state so, and provide an explanation of the circumstances leading to the decision.

A. Tampa Electric originally believed the Lake Hancock Solar project would require additional time to receive its land use approvals. Mountain View Solar was selected as a Tranche 2 project because its interconnection approvals were in advanced stages.

In May 2018, Tampa Electric received Pasco County Planning Commission's approval that the Mountain View Solar site could be used for a PV solar project. One month later an appeal was filed challenging the Planning Commission's approval. The appeal is expected to be heard on August 7, 2018. The appeal process delayed the company's environmental resource permit filing for this project, thus delaying its completion.

In June 2018, Lake Hancock received approval from the City of Bartow to construct a PV solar project on the site. The remaining approval needed to begin construction is the FDEP Environmental Resource Permit ("ERP"). The ERP application for Lake Hancock was filed with the FDEP at the end of June 2018.

Tampa Electric decided to move Lake Hancock Solar to a Tranche 2 project and replace Mountain View Solar because of the Mountain View appeal. The two projects are similar in size, and each is expected to produce 50-55 MWac. This change enables First Solar, the developer, to effectively use its workforce of more than 1,000 workers to construct three of the five Tranche 2 projects while the Mountain View project goes through its appeal process.

19. **Customer Bills.** Please refer to EXH WRA-1, Document No. 4, Page 1 of 4 to the direct testimony of witness Ashburn. Provide a breakdown of a residential customer's 1000 kWh bill, identifying what portion of the proposed rate increase and bill total are attributable to the additional revenue requirements from the sharing mechanism. Please provide all calculations in Excel format, with formulas intact.

A. The requested information is provided in the following table and in the Excel file "20180133 Staff 1st DR No. 19.xlsx."

Revenue Requirements (RR)	Source		(000)	% of Total	Calculation
Tranche 2 RR with Incentive	1		$46,045		
Tranche 2 RR without Incentive	2		45,886		
Difference (Incentive)			$159	0.3453%	+D7/D5
RR by Class	3	RS	$26,145	56.7814%	+D9/D14
		GS	2,272	4.9343%	+D10/D14
		GSD	16,417	35.6543%	+D11/D14
		IS	1,184	2.5714%	+D12/D14
		LTG	27	0.0586%	+D13/D14
		Total	$46,045	100.0000%	
RS Portion of Incentive			$90		+D7*E9
RS Incentive as Percent of RS Total				0.3453%	+D16/D9

Residential Customer Bill Impact 1,000 kWh RS Bill	4 Present Rates	Proposed Rates	Difference	Incentive Difference	
Base Rate	$64.08	$66.55	$2.47	$0.01	+D23*E17
Fuel Charge *	28.18	26.96	-1.22	0.00	
ECCR Charge	2.46	2.46	0	0.00	
Capacity Charge	0.66	0.66	0	0.00	
ECRC Charge	3.43	3.43	0	0.00	
GRT Charge	2.53	2.57	0.04	0.00	+D28*E17
Total	$101.35	$102.63	$1.28	$0.01	

* Incentive Does Not Affect Fuel Charge Difference

1 Direct Testimony of witness Rocha, page 29
2 Direct Testimony of witness Rocha, page 28
3 Direct Testimony of witness Ashburn, page 15, column D
4 Direct Testimony of witness Ashburn, Exhibit WRA-1, Document No. 4, page 1 of 4

20. **Land.** Please refer to Page 12, Lines 12-16, of the direct testimony of witness Ward.

a. When is the permitting process for the Bonnie Mine Solar and Lake Hancock Solar Projects expected to be complete?

b. Does TECO anticipate any delays in the permitting process for either project?

A. a. The Bonnie Mine project ERP was approved by the FDEP in July 2018. The company is awaiting the formal letter from FDEP to be issued, and then the county is expected to issue the county conditional use permit.

The ERP application for the Lake Hancock project was submitted at the end of June 2018. The FDEP is expected to issue the ERP in August, at which time construction may begin.

b. No.

21. **Cost-effectiveness.** Please refer to Page 11, Lines 17-18, of the direct testimony of witness Ward. Explain what the phrase "because they originated their respective project sites" means.

A. Invenergy and Swinerton originated their respective project sites. Invenergy originated the Lithia Solar site and proposed a competitive price to construct the 74.5 MWac project. Swinerton, along with Pacific Northwest Solar, originated the Bonnie Mine Solar site and proposed a competitive price to construct the 37.5 MWac project.

The land parcels for both projects were assigned to Tampa Electric, and Tampa Electric purchased the sites.

22. **Cost-effectiveness.** Please refer to POD No. 3. Identify those costs in the "other traditionally allowed rate base costs" category.

A. With respect to SoBRA cost recovery, paragraph 6(d) of the company's 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Settlement Agreement") states the following:

> The types of costs of solar projects that traditionally have been allowed in rate base (including Engineering, Procurement and Construction ("EPC") costs; development costs including third party development fees, if any; permitting fees and costs; actual land costs and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection costs; installation labor and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters, and modules; AFUDC at the weighted average cost of capital from Exhibit B of this 2017 Agreement; and other traditionally allowed rate base costs) shall be eligible for SoBRA cost recovery.

All of the costs listed in the company's response to POD No. 3 are one of the more specific types of costs listed in the 2017 Settlement Agreement, as opposed to "other traditionally allowed rate base costs."

23. Please refer to the Direct Testimony of Tampa Electric Company (TECO or Company) witness R. James Rocha, page 21, lines 15-25.

a. Please fully explain how the Company developed the $324.9 million projected value of fuel savings presented in this section of testimony.

b. Please identify the source and date of TECO's fuel price forecast used in developing the Current Present Value of Revenue Requirements (CPVRR) analysis of the proposed Second Solar Base Rate Adjustment (SoBRA) Transaction.

c. Please identify the date, if known, of TECO's next/updated fuel price forecast that will be used for Company/business planning purposes.

d. Please discuss TECO's fuel forecast methodology. Please also remark on approximate the length of time TECO has employed this same or very similar fuel forecasting methodology for Company planning purposes.

e. Please fully explain how TECO developed the $24.8 million projected value of reduced emissions presented in this section of testimony.

f. Please identify the sources and dates of all environmental compliance cost related forecasts TECO used in developing its CPVRR analysis of the proposed Second SoBRA Transaction.

g. Please discuss TECO's environmental compliance cost related forecast methodology. Please also remark on approximate the length of a time TECO has employed this same or very similar methodology.

h. Please provide a detailed explanation (with specificity) of the sensitivity analyses TECO performed with regard to forecasted fuel prices and forecasted market prices for carbon dioxide (CO2) in testing the robustness of the projected cost savings.

A. a. Using the company's Integrated Resource Planning process, a long-term base case model was prepared without the second tranche of solar generation. Next, starting from this base case, a change case model was prepared with the second tranche 260.3 MW of solar generation in-service January 2019. Both the base case and change case were run with the production cost modeling software to determine fuel costs for both cases. The change case system fuel cost was then subtracted from the base case system fuel cost equating to $324.9 million in savings to customers.

b. The fuel forecast used in the CPVRR analysis for the second tranche of solar is the company's most recent fuel forecast updated in Summer 2018 and is the same fuel forecast used in preparing the 2019 projected costs and cost recovery factors to be submitted in Docket No. 20180001-EI on August 24, 2018.

c. The fuel price forecast will next be updated in Summer 2019 to prepare the 2020 projected costs and cost recovery factors.

d. Tampa Electric has used the same methodology to forecast fuel commodity prices for approximately ten years. The methodology is consistent across commodities. It uses market indicators (e.g., NYMEX futures contracts) to estimate near-term prices (one to three years). The methodology then uses a commercially available, published fuel commodity price forecast from an independent energy consulting firm (e.g., PIRA, Wood MacKenzie) for the mid-term (two to 20 years). The final long-term portion of the fuel price forecast ~~is~~ then transitions to using an independent, longer term source for the annual price changes (e.g., EIA Long Term Energy Outlook). The source data is blended to transition between time periods. The forecast is produced early each summer to support the late-summer fuel clause actual-estimate and projection filings and is used for one year until the next official forecast is produced.

e. A long-term base case model was prepared without the second tranche of solar. Next, starting from this base case, a change case model was prepared with the second tranche, 260.3 MW of solar in-service January 2019. Both the base case and the change case were run with the production cost modeling software to determine CO_2 and NO_X output for both cases using the company's emission factors. Tampa Electric then calculated the avoided emissions between these two cases and multiplied them by a CO_2 price forecast from a global consulting services company, ICF International, Inc., and an estimated NO_X cost estimated using a previous sale of Tampa Electric's NO_X Ozone Season allowances. These calculations resulted in $24.8 million in projected value of reduced emissions from

NO_X and CO_2, approximately \$23.8 million of CO_2 and \$1.0 million of NO_X forecasted. Several policies and regulations relating to emissions valuation are in various stages of development and/or litigation and the anticipated value of emission reductions is captured in the forecast.

f. The CO_2 price forecast used in the cost-effectiveness analysis for the second tranche of solar was purchased from a global consulting services company, ICF International, Inc., and developed in the third quarter of 2017. The NO_X price forecast is estimated using an actual sale of Tampa Electric's NO_X Ozone Season allowances in 2016 and escalated by one percent a year after 2017.

g. Tampa Electric has been tracking CO_2 impacts since the initial Clean Power Plan talks began around June 2014. Since that time, the company has assessed carbon emissions for each project.

h. The fuel forecast sensitivities used in the CPVRR analysis for the second tranche of solar are from the same fuel forecast used in preparing the 2019 projected costs and cost recovery factors to be submitted on August 24, 2018 in Docket No. 20180001-EI. The high and low fuel forecasts are shown in the company's response to Staff's First POD No. 5. The results of the high and low fuel forecast sensitivities are shown in the following tables:

Delta CPWRR Revenue Requirements - **Base Fuel**	Cost/(Savings) (2018 US $ millions)
Capital RR - Other New Units	($78.8)
Capital RR - Solar New Arrays (w/Interconnect)	$326.7
RR of Land for Solar	$61.2
System VOM	($19.2)
FOM - Other Future Units	$0.0
FOM - Solar Future Arrays	$29.9
System Fuel	($324.9)
System Capacity	($9.1)
Sub Total w/o NOX or CO2 Cost	($14.2)
Plus Emissions Costs	
CO2 - Base	($23.8)
CO2 - High	($86.7)
CO2 - Low	$0.0
NOX - Base	($1.0)
Total w/ CO2 (Base) & NOX Cost	($39.0)
Total w/ CO2 (High) & NOX Cost	($101.9)
Total w/ CO2 (Low) & NOX Cost	($15.2)

Delta CPWRR Revenue Requirements - **High Fuel Sensitivity**	Cost/(Savings) (2018 US $ millions)
Capital RR - Other New Units	($78.8)
Capital RR - Solar New Arrays (w/Interconnect)	$326.7
RR of Land for Solar	$61.2
System VOM	($15.1)
FOM - Other Future Units	$0.0
FOM - Solar Future Arrays	$29.9
System Fuel	($458.0)
System Capacity	($9.1)
Sub Total w/o NOX or CO2 Cost	($143.1)
Plus Emissions Costs	
CO2 - Base	($23.3)
CO2 - High	($82.3)
CO2 - Low	$0.0
NOX - Base	($0.9)
Total w/ CO2 (Base) & NOX Cost	($167.4)
Total w/ CO2 (High) & NOX Cost	($226.3)
Total w/ CO2 (Low) & NOX Cost	($144.0)

Delta CPWRR Revenue Requirements - **Low Fuel Sensitivity**	Cost/(Savings) (2018 US $ millions)
Capital RR - Other New Units	($78.8)
Capital RR - Solar New Arrays (w/Interconnect)	$326.7
RR of Land for Solar	$61.2
System VOM	($20.5)
FOM - Other Future Units	$0.0
FOM - Solar Future Arrays	$29.9
System Fuel	($233.8)
System Capacity	($9.1)
Sub Total w/o NOX or CO2 Cost	$75.6
Plus Emissions Costs	
CO2 - Base	($24.6)
CO2 - High	($88.9)
CO2 - Low	$0.0
NOX - Base	($1.2)
Total w/ CO2 (Base) & NOX Cost	$49.8
Total w/ CO2 (High) & NOX Cost	($14.5)
Total w/ CO2 (Low) & NOX Cost	$74.4

24. Please provide a summary of all the existing federal, state, and local government policies and rules regarding the regulation of CO2 emissions. Please also discuss the economic impacts of any such policies or rules.

A. The following is a summary of the potentially relevant existing federal policies and rules regarding the regulation of CO_2 emissions and economic impacts if applicable. There are currently no state or local policies or rules relevant to the subject testimony.

Greenhouse Gas Mandatory Reporting Rule – 40 CFR 98: In 2009, the Environmental Protection Agency ("EPA") promulgated a regulation to require reporting of greenhouse gas emissions from multiple sectors of the economy. The final rule applies to fossil fuel suppliers and industrial gas suppliers, direct greenhouse gas emitters and manufacturers of heavy-duty and off-road vehicles and engines. The rule does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions. Tampa Electric's Greenhouse Gas ("GHG") Reporting program was approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PAA-EI, issued March 22, 2010, and is a result of the EPA's Mandatory reporting rule requiring annual reporting of greenhouse gas emissions. Tampa Electric was required to report greenhouse gas emissions for the first time in 2011. Reporting for the EPA's Greenhouse Gas Mandatory Reporting rule will continue in 2018. For 2018, this activity is projected to result in approximately $93,149 of O&M expenditures.

Prevention of Significant Deterioration - 40 CFR 52: This EPA rule became effective January 2, 2011. It addresses the GHG emission threshold triggers that would require permitting review of new and/or major modifications to existing stationary sources of GHG emissions. A subsequent U. S. Supreme Court ruling narrowed the EPA's authority to implement this rule, but the key provisions remain applicable to Tampa Electric. While this rule does not have an immediate impact on Tampa Electric's operations, GHG permitting was completed for Tampa Electric's most recent base load unit, the Polk Unit 2 – 5 conversion to combined cycle. These standards do not directly pertain to the scope of the subject testimony; however, the standards are not expected to have any significant economic impact to Tampa Electric's current plans to meet load demand.

New Source Performance Standards (NSPS) – 40 CFR 60 Subpart TTTT: The New Source Performance Standards (NSPS) for CO_2 emissions from new electric generating units were promulgated on October 23, 2015. The rule is applicable to any steam generating unit, integrated gasification combined cycle, or stationary CTG that commenced construction after January 8, 2014, or commenced modification or reconstruction after June 18, 2014. This rule is being challenged in the D.C. Circuit, and the case is currently in temporary abeyance. These standards do not directly pertain to the scope of the subject testimony; however, the standards are not expected to have any significant economic impact to Tampa Electric's current plans to meet load demand.

Standards for Modified/Reconstructed Sources - 40 CFR 60 Subpart TTTT: On October 23, 2015, EPA published final standards for existing units that are modified or reconstructed. This rule is being challenged in the D.C. Circuit. These standards do not directly pertain to the scope of the subject testimony; however, the standards are not expected to have any significant economic impact to Tampa Electric's current plans to meet load demand.

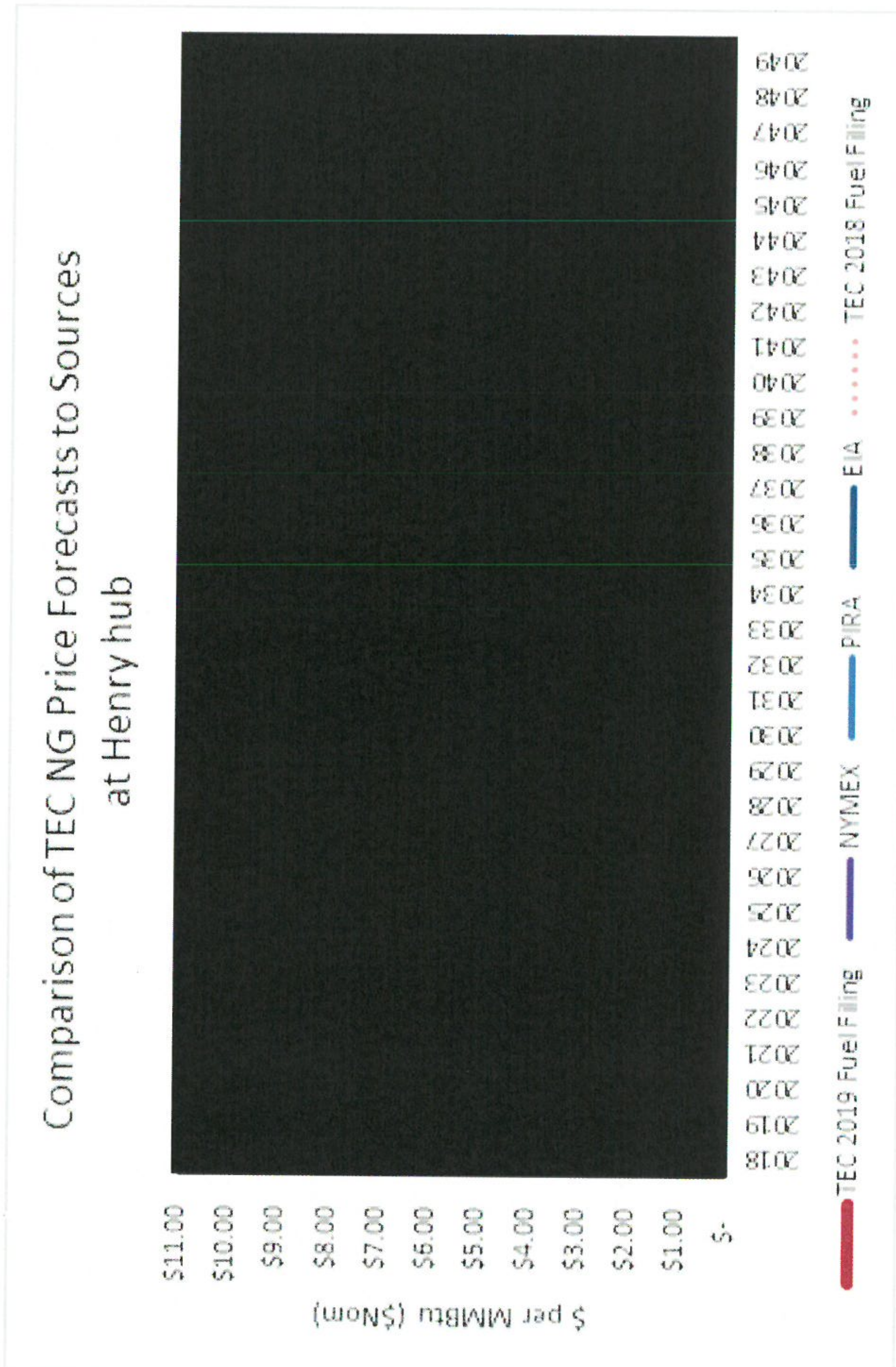
Emission Guidelines and State Standards for Existing Sources (Clean Power Plan) - 40 CFR 60 Subpart UUUU: On October 23, 2015, EPA published final Emission Guidelines for existing utility units, setting individual statewide emission rate goals, and directing states to submit initial plans to achieve the goal by September 6, 2016. On Feb. 9, 2016 the Supreme Court stayed implementation of the rule. Florida Department of Environmental Protection ("FDEP") is not actively working on any state plan due to the Supreme Court's stay. These standards were designed to incentivize renewable energy development that is in the scope of the proposed projects. However, on October 16, 2017, EPA published a notice of its intent to repeal the Clean Power Plan rules for existing units. On December 28, 2017, EPA published an Advance Notice of Proposed Rulemaking to solicit comments on EPA's consideration of a new rule to limit GHGs from existing electric generating units. Since the Clean Power Plan replacement rule is in the early stages of development, Tampa Electric utilized the ICF International, Inc. study developed in the third quarter of 2017 to provide a forecasted cost of CO_2 emissions.

25. To date, has TECO incurred any costs related to emissions of CO2? If so, please discuss the economic details as well as the method of cost recovery.

a. If the response is negative, when does TECO believe it will be affected by CO2 emissions regulation/costs for emitting?

A. a. As described in the response to Data Request No. 24, Tampa Electric's GHG Reporting program is the only program for which Tampa Electric has incurred costs related to CO_2 emissions, to date. Cost recovery through the Environmental Cost Recovery Clause was approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PAA-EI, issued March 22, 2010, to comply with the EPA's Mandatory Reporting Rule requiring annual reporting of greenhouse gas emissions. Tampa Electric was required to report greenhouse gas emissions for the first time in 2011. Reporting for the EPA's Greenhouse Gas Mandatory Reporting Rule will continue in 2018 at an estimated cost of $95,974.

REDACTED



Comparison of TEC NG Price Forecasts to Sources at Henry hub
$ per MMBtu ($Nom)
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
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TEC 2019 Fuel Filing
NYMEX
PIRA
EIA
TEC 2018 Fuel Filing

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TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
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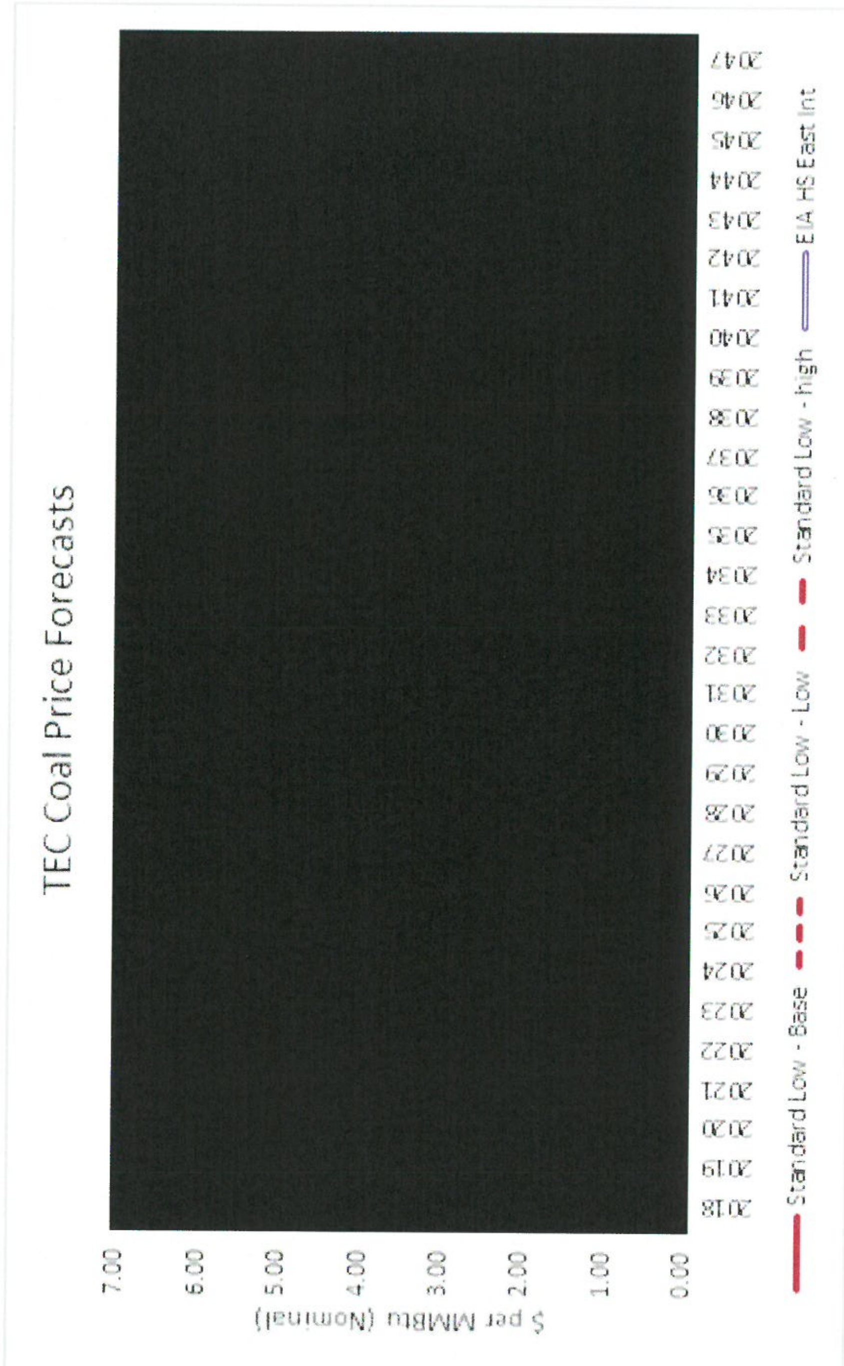
FILED: AUGUST 1, 2018



27. Please refer to the Direct Testimony of TECO witness Rocha, Exhibit RJR-1, Document No. 5, Page 1 of 1. Please discuss how the CO2 and nitrogen oxide (NOx) reduction amounts presented in this exhibit were formulated.

a. Please provide the percent error in TECO's delivered natural gas price forecasts 3 to 5 years out using data which supported TECO's 2010 through 2014 Ten Year Site Plans, per the following tables. Please provide an explanation for any forecast error rate in excess of 20 percent.

Accuracy of Natural Gas Price Forecasts

ear	Natural Gas Price Annual Forecast Error Rate (%)		
	Years Prior		
	5	4	3
2015			
2016			
2017			
Average			

Natural Gas Price Forecasts

Year	Natural Gas Price Annual Forecast (\$/MMbtu)		
	Years Prior		
	5	4	3
2015			
2016			
2017			
Average			

Natural Gas Price

Year	Natural Gas Price Annual Actuals (\$/MMbtu)		
	Years Prior		
	5	4	3
2015			
2016			
2017			
Average			

A. Regarding emissions, Tampa Electric has been monitoring forecasted carbon prices since the draft Clean Power Plan was issued. The company reviewed forecasts that other IOUs included with their Commission filings, as well as public forecasts found on the internet, such as those of Synapse Energy. Tampa Electric contracted with a global consulting services company, ICF International, Inc., to obtain a CO_2 forecast that utilized the most current assumptions and market conditions. The consultant compared projections for various regions of the country and included low, medium, and high forecasts. Tampa Electric estimated the NO_x cost using a recent, very small sale of Tampa Electric's NO_x Ozone Season allowances.

a. Tampa Electric recommends caution in drawing conclusions from the requested window of information. These forecasts were produced in 2010 to 2012 for the years 2015 – 2017. The requested information is provided in the following tables.

Accuracy of Natural Gas Price Forecasts

Year	Natural Gas Price Annual Forecast Error Rate (%)		
	Years Prior		
	5	4	3
2015	-52%	-51%	-41%
2016	-54%	-54%	-46%
2017	-55%	-56%	-48%
Average	-53%	-54%	-45%

Natural Gas Price Forecasts

Year	Natural Gas Price Annual Forecast ($/MMbtu)		
	Years Prior		
	5[A]	4[B]	3[C]
2015	8.66	8.64	7.14
2016	8.76	8.83	7.39
2017	8.88	9.01	7.65
Average	8.76	8.83	7.39
Notes:			
A. Forecasted prices 2015 - 2017 from 2010 TYSP **B.** Forecasted prices 2015 - 2017 from 2011 TYSP **C.** Forecasted prices 2015 - 2017 from 2012 TYSP			

Natural Gas Price

Year	Natural Gas Price Annual Actuals ($/MMbtu)		
	Years Prior		
	5^D	4	3
2015	4.20		
2016	4.02		
2017	4.01		
Average	4.08		
Notes:			
D. Actual Fuel Prices			

Actual natural gas prices often vary from forecasted prices by more than 20 percent. This occurs despite the forecasted prices being based on independent, industry-recognized sources. The variance derives from an ongoing revolution in the production of natural gas from shale rock that began around 2009. That revolution has accelerated through technology and expanded into crude oil production. The price of natural gas in recent years (2015 through 2017) has been depressed compared to projected prices based on typical supply-demand-cost relationships because the associated natural gas produced from crude oil production has flooded the natural gas market. It is being produced based on crude oil production margins, not natural gas fundamentals. Industry experts are recognizing this phenomenon and factoring it into their future forecasts.

28. Please provide the percent error in TECO's delivered coal price forecasts 3 to 5 years out using data which supported TECO's 2010 through 2014 Ten Year Site Plans, per the following tables. Please provide an explanation for any forecast error rate in excess of 15 percent.

Accuracy of Coal Price Forecasts

Year	Coal Price Annual Forecast Error Rate (%)		
	Years Prior		
	5	4	3
2015			
2016			
2017			
Average			

Coal Price Forecasts

Year	Coal Price Annual Forecast ($/MMbtu)		
	Years Prior		
	5	4	3
2015			
2016			
2017			
Average			

Coal Price

Year	Coal Price Annual Actuals ($/MMbtu)		
	Years Prior		
	5	4	3
2015			
2016			
2017			
Average			

A. Tampa Electric recommends caution in drawing conclusions from the requested window of information. The forecasts are from 2010 through 2012, 5 to 10 years prior to the forecasted period. The requested information is provided in the following tables.

Several things have changed dramatically in the coal industry over the past decade. Beginning with the spike in coal prices led by international coal in 2008 and 2012, the price of U.S. domestic coal in the east is shifting from a cost-based supply to a pricing model based on the value of delivered solid fuel to China/India/South Africa. This evolution has been exacerbated by the closure of numerous mines and the consolidation of producers as the result of higher costs to produce, lower projected domestic coal consumption, and numerous bankruptcy proceedings. This evolution means that the surviving mines are mostly those with access to international markets via export. These facilities will be pricing their product based on the higher of the net from the international market or the domestic alternative. Thus, the actual price of coal has increased compared to the forecasts that were produced during the early 2010's.

Accuracy of Coal Price Forecasts

Year	Coal Price Annual Forecast Error Rate (%)		
	Years Prior		
	5	4	3
2015	17%	-23%	-19%
2016	17%	-19%	-13%
2017	1%	-28%	-23%
Average	12%	-23%	-18%

Coal Price Forecasts

Year	Coal Price Annual Forecast ($/MMbtu)		
	Years Prior		
	5[A]	4[B]	3[C]
2015	2.86	4.34	4.13
2016	3.01	4.37	4.04
2017	3.11	4.40	4.08
Average	2.99	4.37	4.08
Notes:			
A. Forecasted prices 2015 - 2017 from 2010 TYSP B. Forecasted prices 2015 - 2017 from 2011 TYSP C. Forecasted prices 2015 - 2017 from 2012 TYSP			

Coal Price

Year	Coal Price Annual Actuals ($/MMbtu)		
	Years Prior		
	5[D]	4	3
2015	3.35		
2016	3.52		
2017	3.15		
Average	3.34		
Notes:			
D. Actual Fuel Prices			

23. Please refer to the Direct Testimony of Tampa Electric Company (TECO or Company) witness R. James Rocha, page 21, lines 15-25.

a. Please fully explain how the Company developed the $324.9 million projected value of fuel savings presented in this section of testimony.

b. Please identify the source and date of TECO's fuel price forecast used in developing the Current Present Value of Revenue Requirements (CPVRR) analysis of the proposed Second Solar Base Rate Adjustment (SoBRA) Transaction.

c. Please identify the date, if known, of TECO's next/updated fuel price forecast that will be used for Company/business planning purposes.

d. Please discuss TECO's fuel forecast methodology. Please also remark on approximate the length of time TECO has employed this same or very similar fuel forecasting methodology for Company planning purposes.

e. Please fully explain how TECO developed the $24.8 million projected value of reduced emissions presented in this section of testimony.

f. Please identify the sources and dates of all environmental compliance cost related forecasts TECO used in developing its CPVRR analysis of the proposed Second SoBRA Transaction.

g. Please discuss TECO's environmental compliance cost related forecast methodology. Please also remark on approximate the length of a time TECO has employed this same or very similar methodology.

h. Please provide a detailed explanation (with specificity) of the sensitivity analyses TECO performed with regard to forecasted fuel prices and forecasted market prices for carbon dioxide (CO_2) in testing the robustness of the projected cost savings.

A. Tampa Electric provides the following supplemental response to subpart (h).

h. Tampa Electric has used the same methodology to forecast fuel commodity prices for approximately ten years. The methodology is consistent across commodities. For the base case, it uses market indicators (e.g., NYMEX futures contracts) to estimate near-term prices (one to three years). The methodology then uses a commercially available, published fuel commodity price forecast from an independent energy consulting firm (e.g., PIRA, Wood MacKenzie) for the mid-term (two to 20 years). The final long-term portion of the fuel price forecast then transitions to using an independent, longer term source for the annual price changes (e.g., EIA Long Term Energy Outlook). The source data is blended to transition between time periods. The forecast is produced early each summer to support the late-summer fuel clause actual-estimate and projection filings and is used for one year until the next official forecast is produced.

The high and low fuel forecasts are determined by transitioning from the current year base case fuel prices to the high and low fuel price sensitivities provided by PIRA for the near and mid-term pricing. For the long-term time period, the company transitions to EIA's "High Resource" (low fuel price) and "Low Resource" (high fuel price) sensitivities to extend the low and high fuel price forecasts to the end of the forecast period.

The company's purchased CO_2 cost forecast included base, high and low cases.

6

Staff's First Data Request "Production of Documents" Nos. 1 – 11

Confidential DN. 05032-2018

(Nos. 2, 3, 6)

[4] Id.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180133-EI EXHIBIT: 6
PARTY: STAFF – (DIRECT)
DESCRIPTION: James Rocha1, 5-7Mark Ward2-4William R. Ashburn8-11

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for limited proceeding to approve second solar base rate adjustment (SoBRA), effective January 1, 2019, by Tampa Electric Company.	**DOCKET NO. 20180133-EI** **FILED: AUGUST 1, 2018**

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST REQUEST FOR

PRODUCTION OF DOCUMENTS (NOS. 1 - 11)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Production of Documents (Nos. 1 - 11) propounded and served on July 18, 2018 by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
INDEX TO STAFF'S FIRST REQUEST FOR
PRODUCTION OF DOCUMENTS (NOS. 1 - 11)

Number	Subject	Bates Stamped Pages
1	**Resource Planning.** Please provide a copy of TECO's 2018 Ten-Year Site Plan in PDF format.	1 -93
2	**Cost-effectiveness**. Please refer to Page 10, Lines 11-15, of the direct testimony of witness Ward. Provide the pricing information received from the shortlisted developers for the seven solar PV projects, broken out into engineering and permitting, equipment, balance of system, installation, and interconnection.	94 - 95
3	**Cost-effectiveness.** Please refer to Page 16, Lines 10-25, and Page 17, Lines 1-2, of the direct testimony of witness Ward. Provide the calculations and workpapers used to determine the projected total installed cost of each of the Second SoBRA Projects, broken down into EPC costs, development costs, third party development fees, permitting costs, land acquisition costs, taxes, utility costs to support or complete development, transmission interconnection costs, modules and equipment costs, costs associated with electrical balance of system, costs associated with structural balance of system, allowance for funds used during construction, and other traditionally allowed rate base costs. If the documents are available in Excel format, please provide them as such with all formulas intact.	96- 101
4	**Cost-effectiveness**. Please refer to Page 18, Lines 11-17, of the direct testimony of witness Ward. Provide the calculations used to determine the projected weighted average costs of the First SoBRA, the Second SoBRA, and the First and Second SoBRAs together. If the document is available in Excel format, please provide it as such with all formulas intact.	102
5	Please refer to the Direct Testimony of TECO witness Rocha, page 21, lines 15-25. Please provide copies of the Company's high and low fuel forecasts relied upon in developing its CPVRR analysis discussed in this section of testimony.	103 -105
6	Please refer to the Direct Testimony of TECO witness Rocha, page 21, lines 15-25. Please provide copies of the Company's base, high, and low environmental compliance cost forecasts relied upon in developing its CPVRR analysis referenced in this section of testimony.	106- 108
7	Please refer to the Direct Testimony of TECO witness Rocha, page 16, lines 21-25. Please provide all (if any) alternative fuel and emissions forecasts TECO used to gauge the robustness	109

Number	Subject	Bates Stamped Pages
	of its proposed SoBRA transaction.	
8	Appendix B (Typical Bill Analysis) to the petition indicates a bill increase of $1.28 per month for residential customers who use 1,000 kWh per month. Considering the proposed bill impacts stated above, please discuss how and when TECO will inform its customers about the proposed changes. Also, please provide examples of a customer letter, website information, door hanger, press release etc. that are considered TECO's communication methods to inform customers of bill impacts.	110 - 112
9	TECO requests that the proposed tariff changes if approved be effective with the first billing cycle of January 2019. Please indicate when the first billing cycle of January will begin.	113
10	Twenty-fourth revised tariff sheet 6.030 indicates that the energy and demand charge for the first 1,000 kWh for residential service will increase from 4.896 cents per kWh to 5.143 cents per kWh. Please discuss the reason for this increase.	114
11	Page 9 of witness Ashburn's direct testimony states that certain rates in each rate class were increased to recover the identified revenue requirement. Please expand on this statement.	115

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
STAFF'S FIRST REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 1
BATES STAMPED PAGES: 1 - 93
FILED: AUGUST 1, 2018

1. **Resource Planning.** Please provide a copy of TECO's 2018 Ten-Year Site Plan in PDF format.

A. Attached, please find Tampa Electric's 2018 Ten Year Site Plan. This file is also provided as "2018 TYSP – TEC.pdf".

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

April 2, 2018

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Tampa Electric Company's 2018 Ten-Year Site Plan

Dear Ms. Stauffer:

Attached for filing on behalf of Tampa Electric Company is the company's January 2018 to December 2027 Ten-Year Site Plan.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

James D. Beasley

JDB/pp
Attachment

Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2018 to December 2027

Submitted to: Florida Public Service Commission
April 2, 2018

TABLE OF CONTENTS

LIST OF SCHEDULES & TABLES

LIST OF FIGURES

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GLOSSARY OF TERMS

CODE IDENTIFICATION SHEET

Unit Type:	CC	=	Combined Cycle
	D	=	Diesel
	FS	=	Fossil Steam
	GT	=	Gas Turbine (includes jet engine design)
	HRSG	=	Heat Recovery Steam Generator
	IC	=	Internal Combustion
	IGCC	=	Integrated Gasification Combined Cycle
	PV	=	Photovoltaic
	ST	=	Steam Turbine
Unit Status:	LTRS	=	Long-Term Reserve Stand-By
	OP	=	Operating (In commercial operation)
	OT	=	Other
	P	=	Planned
	T	=	Regulatory Approval Received
	U	=	Under Construction, less than or equal to 50 percent complete
	V	=	Under Construction, more than 50 percent complete
Fuel Type:	BIT	=	Bituminous Coal
	RFO	=	Residual Fuel Oil (Heavy - #6 Oil)
	DFO	=	Distillate Fuel Oil (Light - #2 Oil)
	NG	=	Natural Gas
	PC	=	Petroleum Coke
	WH	=	Waste Heat
	BIO	=	Biomass
	SOLAR	=	Solar Energy
Environmental:	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	SCR	=	Selective Catalytic Reduction
Transportation:	PL	=	Pipeline
	RR	=	Railroad
	TK	=	Truck
	WA	=	Water
Other:	EV	=	Electric Vehicle(s)
	NA	=	Not Applicable

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Executive Summary

Tampa Electric Company's (TEC) 2018 Ten Year Site Plan (TYSP) features plans to enhance electric generating capability as part of our efforts to meet projected incremental resource needs for 2018 through 2027. The 2018 TYSP provides the Florida Public Service Commission (FPSC) with assurance that TEC will be able to supply cost effective alternatives to ensure the delivery of adequate, safe and reliable power to TEC's customers.

The Polk 2 Combined Cycle conversion project was completed in January 2017, increasing incremental capacity by 480 MW winter and 461 MW summer. TEC also completed a 19.4 MW_{AC} PV solar array located at Big Bend Power Station with commercial operation in February 2017. In addition, TEC will add 144.7 MW_{AC} of solar PV across multiple sites in September 2018; that total will increase to over 400 MW_{AC} of solar PV by January 2019 and ultimately 600 MW_{AC} of solar PV by 2021. TEC will phase in a modernization of Big Bend through the repowering of unit 1 by 2023 into a highly efficient combined cycle unit and retiring unit 2. Additionally, TEC will add peaking combustion turbines in 2023 and 2026 to meet reserve margin in future years.

TEC is committed to reliably serve the system's demand and energy requirements for the customers located in its service area as shown in Figure I-I. TEC will continue to meet resource requirements with the most economical combination of Demand Side Management (DSM), conservation, renewable energy, purchased power, and generation capacity additions. The resource additions in TEC's 2018 TYSP are projected to be needed based on our current Integrated Resource Planning (IRP) process. The IRP process incorporates an on-going evaluation of demand and supply resources and conservation measures to maintain system reliability. The IRP process is discussed further in Chapter III.

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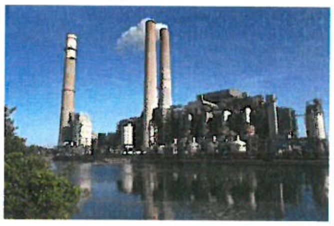
Chapter I

DESCRIPTION OF EXISTING FACILITIES

Tampa Electric has three (3) generating stations that include fossil steam units, combined cycle units, combustion turbine peaking units, an integrated coal gasification combined cycle unit and multiple solar facilities.

Big Bend Power Station

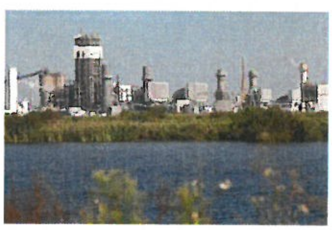


Big Bend units 1-4 are four (4) pulverized coal-fired steam units equipped with desulfurization scrubbers, electrostatic precipitators, and Selective Catalytic Reduction (SCR) air pollution control systems. All four units can also be fired with natural gas. Big Bend CT 4 is one (1) aero-derivative combustion turbine that entered into service in 2009 and can be fired with natural gas or distillate oil.

H.L. Culbreath Bayside Power Station

The station operates two (2) natural gas-fired combined cycle units and (4) aero derivative combustion turbines. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) heat recovery steam generators (HRSGs) and one (1) steam turbine. Bayside Unit 2 utilizes four (4) combustion turbines, four (4) HRSGs and one (1) steam turbine. Bayside 3, 4, 5, and 6 are four (4) natural gas fired aero-derivative combustion turbines that were placed into service in 2009.

Polk Power Station



The station operates one (1) integrated coal gasification combined cycle (IGCC) unit and one (1) natural gas-fired combined cycle unit. Polk Unit 1 is an IGCC unit fired with synthetic gas produced from gasified coal and other carbonaceous fuels. This technology integrates state-of-the-art environmental processes to create a clean fuel gas from a variety of feedstock with the efficiency benefits of combined cycle generation equipment. Unit 1 can also be fired with natural gas. On January 16, 2017, Polk 2 Combined Cycle entered commercial operation. Polk 2 CC utilizes four (4) combustion turbines (formerly Polk 2-5 simple cycle CT's), four (4) HRSGs and one (1) steam turbine.

Solar

TEC owns a 1.6 MW_{AC} fixed tilt solar PV array located atop the south parking garage of Tampa International Airport that was placed into service in 2015. The 1.4 MW_{AC} solar PV array located at LEGOLAND® Florida began operation on December 8, 2016. The 19.4 MW_{AC} Big Bend Solar Station located near Big Bend Power Station began operation on February 10, 2017. In addition, TEC will place in service over 400 MW_{AC} of single axis tracking PV solar by January 2019.

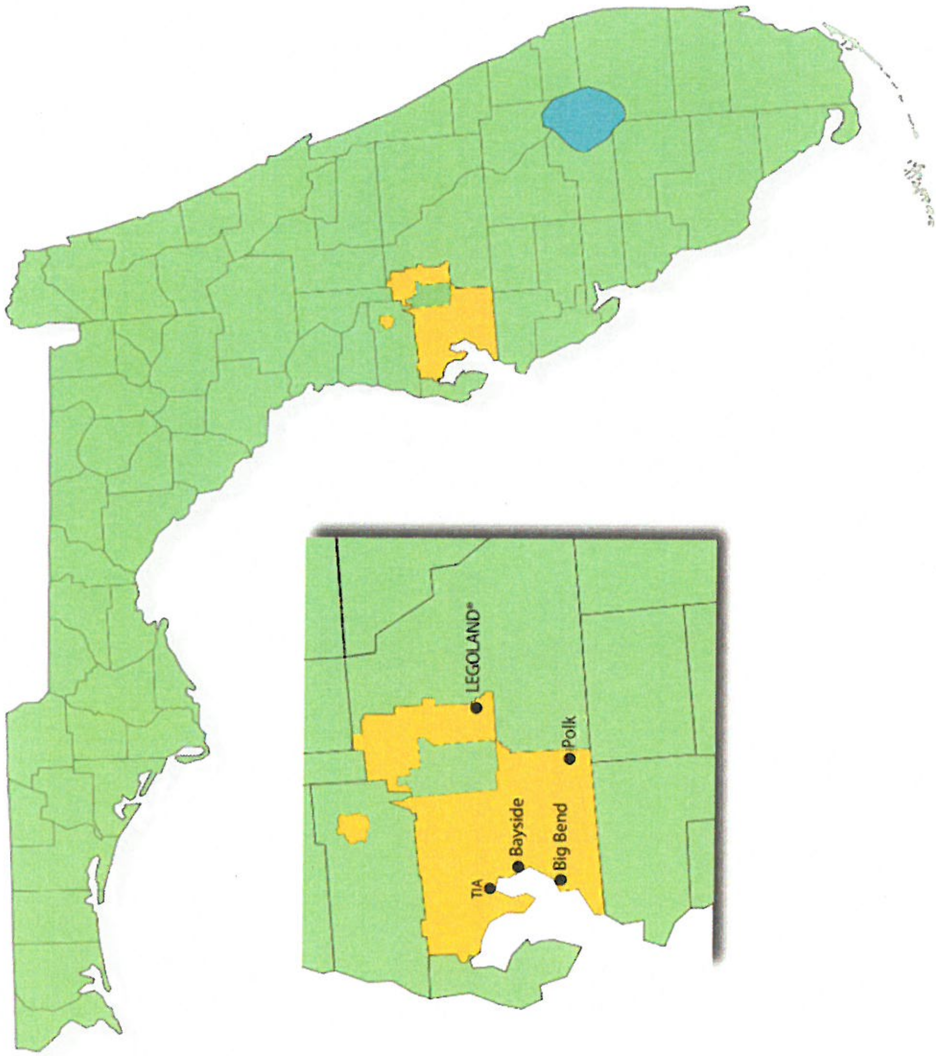
Schedule 1

Existing Generating Facilities
As of December 31, 2017

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days	(10) Commercial In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen. Max. Nameplate kW	(13) Net Capability Summer MW	(14) Net Capability Winter MW
Big Bend		Hillsborough Co.											
		14/31S/19E									1,892,400	1,658	1,693
	1		ST	BIT	NG	WA/RR	PL	NA	10/70	**	445,500	385	395
	2		ST	BIT	NG	WA/RR	PL	NA	04/73	06/2021	445,500	385	395
	3***		ST	BIT	NG	WA/RR	PL	NA	05/76	**	445,500	395	400
	4***		ST	BIT	NG	WA/RR	PL	NA	02/85	**	486,000	437	442
	CT 4		GT	NG	DFO	PL	TK	*	08/09	**	69,900	56	61
Bayside		Hillsborough Co.											
		4/30S/19E									2,293,759	1,854	2,083
	1		CC	NG	NA	PL	NA	NA	04/03	**	809,060	701	792
	2		CC	NG	NA	PL	NA	NA	01/04	**	1,205,100	929	1,047
	3		GT	NG	NA	PL	NA	NA	07/09	**	69,900	56	61
	4		GT	NG	NA	PL	NA	NA	07/09	**	69,900	56	61
	5		GT	NG	NA	PL	NA	NA	04/09	**	69,900	56	61
	6		GT	NG	NA	PL	NA	NA	04/09	**	69,900	56	61
Polk		Polk Co.											
		2,3/32S/23E									1,542,379	1,281	1,420
	1		IGCC	PC/BIT	NG	WA/TK	PL	*	09/96	**	326,299	220	220
	2		CC	NG	DFO	PL	TK	*	01/17	**	1,216,080	1,061	1,200
TIA		Hillsborough Co.											
	1	31/28S/18E	PV	SOLAR	NA	NA	NA	NA	12/15	**	1,600	1.6	1.6
LEGOLAND®		Polk Co.											
	1	02/29S/26E	PV	SOLAR	NA	NA	NA	NA	12/16	**	1,400	1.4	1.4
Big Bend Solar		Hillsborough Co.											
	1	15/31S/19E	PV	SOLAR	NA	NA	NA	NA	02/17	**	19,800	19.4	19.4
Solar Total											22,800	22	22
											TOTAL	4,815	5,218

Notes:
* Limited by environmental permit
** Undetermined
*** Combined net capability will be limited effective January 2023

Figure I-I: Tampa Electric Service Area Map



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Chapter II

TAMPA ELECTRIC COMPANY FORECASTING METHODOLOGY

The customer, demand and energy forecasts are the foundation from which the IRP is developed. Recognizing its importance, TEC employs the necessary methodologies for carrying out this function. The primary objective of this procedure is to blend proven statistical techniques with practical forecasting experience to provide a projection that represents the highest probability of occurrence.

This chapter is devoted to describing TEC's forecasting methods and the major assumptions utilized in developing the 2018-2027 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the 2018-2027 time period.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2018-2027 customer, demand and energy forecasts. This software allows a platform for the development of more dynamic and fully integrated models.

In addition, TEC uses MetrixLT, which integrates with MetrixND to develop multiple-year forecasts of energy usage at the hourly level. This tool allows the annual or monthly forecasts in MetrixND to be combined with hourly load shape data to develop a long-term "bottom-up" forecast that is consistent with short-term statistical forecasts.

TEC's retail customer, demand and energy forecasts are the result of six separate forecasting analyses:

1. Economic Analysis
2. Customer Multiregression Model
3. Energy Multiregression Model
4. Peak Demand Multiregression Model
5. Interruptible Demand and Energy Analysis
6. Conservation, Load Management and Cogeneration Programs

The MetrixND models are the company's most sophisticated and primary load forecasting models. The phosphate demand and energy are forecasted separately and then combined in the final forecast, as well as the effects of photovoltaic (PV) and electric vehicle (EV) related energy. Likewise, the effects of TEC's conservation, load management, and cogeneration programs are incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

1. Economic Analysis

The economic assumptions used in the forecast models are derived from forecasts from Moody's Analytics and the University of Florida's Bureau of Economic and Business Research (BEBR).

See the "Base Case Forecast Assumptions" section of this chapter for an explanation of the most significant economic inputs to the MetrixND models.

2. Customer Multiregression Model

The customer multiregression forecasting model is a seven-equation model. The primary economic drivers in the customer forecast models are population estimates, new construction, and employment growth. Below is a description of the models used for the five-customer classes.

1. *Residential Customer Model:* Customer projections are a function of regional population. Since a strong correlation exists between regional population and historical changes in service area customers, regional population estimates were used to forecast the future growth patterns in residential customers.

2. *Commercial Customer Model:* Total commercial customers include commercial customers plus temporary service customers (temporary poles on construction sites); therefore, two models are used to forecast total commercial customers:

    a. The <u>Commercial Customer Model</u> is a function of population. An increase in the number of households provides the need for additional services, restaurants, and retail establishments. The amount of residential activity also plays a part in the attractiveness of the Tampa Bay area as a place to relocate or start a new business.

    b. Projections of permits in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the <u>Temporary Service Model</u> projects the number of customers as a function of new construction permits.

3. *Industrial Customer Model (Non-Phosphate):* Non-phosphate industrial customers include two rate classes that have been modeled individually: General Service and General Service Demand.
    a. The <u>General Service Customer Model</u> is a function of Hillsborough County commercial employment.

    b. The <u>General Service Demand Customer Model</u> is a function of employment in the manufacturing sector as well as recent trends.

4. *Public Authority Customer Model:* Customer projections are based on the recent growth trend in the sector.

5. *Street & Highway Lighting Customer Model:* Customer projections are based on the recent growth trend in the sector.

3. Energy Multiregression Model

There are a total of seven energy models. All of these models represent average usage per customer (kWh/customer), except for the temporary services model which represents total kWh sales. The average usage models interact with the customer models to arrive at total sales for each class.

The energy models are based on an approach known as Statistically Adjusted Engineering (SAE). SAE entails specifying end-use variables, such as heating, cooling and base use appliance/equipment, and incorporating these variables into regression models. This approach allows the models to capture long-term structural changes that end-use models are known for, while also performing well in the short-term time frame, as do econometric regression models.

1. *Residential Energy Model:* The residential forecast model is made up of three major components: (1) end-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements; (2) changes in the economy such as household income, household size, and the price of electricity; and, (3) weather variables, which serve to allocate the seasonal impacts of weather throughout the year. The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment (XHeat y,m), cooling equipment (XCool y,m), and other equipment (XOther y,m). The XHeat, XCool, and XOther variables are defined as a product of an annual equipment index and a monthly usage multiplier.

$$\text{Average Usage}_{y,m} = (\text{XHeat}_{y,m} + \text{XCool}_{y,m} + \text{XOther}_{y,m})$$

Where:

$$\text{XHeat}_{y,m} = \text{HeatEquipIndex}_{y} \times \text{HeatUse}_{y,m}$$
$$\text{XCool}_{y,m} = \text{CoolEquipIndex}_{y} \times \text{CoolUse}_{y,m}$$
$$\text{XOtherUse}_{y,m} = \text{OtherEquipIndex}_{y} \times \text{OtherUse}_{y,m}$$

The annual equipment variables (HeatEquipIndex, CoolEquipIndex, OtherEquipIndex) are defined as a weighted average across equipment types multiplied by equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations and operating efficiencies. The weights are defined by the estimated energy use per household for each equipment type in the base year.

Where:

$$\textbf{HeatEquipIndex} = \sum_{Tech} \text{Weight} \times \left(\frac{\text{Saturation}_{y} / \text{Efficiency}_{y}}{\text{Saturation}_{base\,y} / \text{Efficiency}_{base\,y}} \right)$$

$$\textbf{CoolEquipIndex} = \sum_{Tech} \text{Weight} \times \left(\frac{\text{Saturation}_{y} / \text{Efficiency}_{y}}{\text{Saturation}_{base\ y} / \text{Efficiency}_{base\ y}} \right)$$

$$\textbf{OtherEquipIndex} = \sum_{Tech} \text{Weight} \times \left(\frac{\text{Saturation}_{y} / \text{Efficiency}_{y}}{\text{Saturation}_{base\ y} / \text{Efficiency}_{base\ y}} \right)$$

Next, the monthly usage multiplier or utilization variables (HeatUse, CoolUse, OtherUse) are defined using economic and weather variables. A customer's monthly usage level is impacted by several factors, including weather, household size, income levels, electricity prices and the number of days in the billing cycle. The degree-day variables serve to allocate the seasonal impacts of weather throughout the year, while the remaining variables serve to capture changes in the economy.

$$\textbf{HeatUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{base\ y,m}}\right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{base\ y,m}}\right)^{.15} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{base\ y,m}}\right)^{.15} \times \left(\frac{\text{HDD}_{y,m}}{\text{Normal HDD}}\right)$$

$$\textbf{CoolUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{base\ y,m}}\right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{base\ y,m}}\right)^{.15} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{base\ y,m}}\right)^{.15} \times \left(\frac{\text{CDD}_{y,m}}{\text{Normal CDD}}\right)$$

$$\textbf{OtherUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{base\ y,m}}\right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{base\ y,m}}\right)^{.15} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{base\ y,m}}\right)^{.15} \times \left(\frac{\text{Billing Days}_{y,m}}{\text{Billing Days}_{base\ y,m}}\right)$$

The SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels and gives estimates of weather sensitivities that vary over time as well as estimate trend adjustments.

2. *Commercial Energy Models:* total commercial energy sales include commercial sales plus temporary service sales (temporary poles on construction sites); therefore, two models are used to forecast total commercial energy sales.

    a. Commercial Energy Model: The model framework for the commercial sector is the same as the residential model. It also has three major components and utilizes the SAE model framework. The differences lie in the type of end-use equipment and in the economic variables used. The end-use equipment variables are based on commercial appliance/equipment saturation and efficiency assumptions. The economic drivers in the commercial model are commercial productivity measured in terms of dollar output and the price of electricity for the commercial sector. The third component, weather variables, is the same as in the residential model.

    b. Temporary Service Energy Model: This model is a subset of the total commercial sector and is a rather small percentage of the total commercial sector. Although small in nature, it is still a component that needs to be included. A simple regression model is used with the primary driver being temporary service customer growth.

3. *Industrial Energy Model (Non-Phosphate):* Non-phosphate industrial energy includes two rate classes that have been modeled individually: General Service and General Service Demand.

    a. The General Service Energy Model utilizes the same SAE model framework as the commercial energy model. The weather component is consistent with the residential and commercial models.

    b. The General Service Demand Energy Model is based on manufacturing output, the price of electricity in the industrial sector, cooling degree-days and number of days billed. Unlike the previous models discussed, heating load does not impact this sector.

4. *Public Authority Sector Model:* Within this model, the equipment index is based on the same commercial equipment saturation and efficiency assumptions used in the commercial model. The economic component is based on government sector productivity and the price of electricity in this sector. Weather variables are consistent with the residential and commercial models.

5. *Street & Highway Lighting Sector Model:* The street and highway lighting sector is not impacted by weather; therefore; it is a rather simple model and the SAE modeling approach does not apply. The model is a linear regression model where street and highway lighting energy consumption is a function of the number of billing days in the cycle, and the number of daylight hours in a day for each month. Starting in 2017, street and highway lighting data will be included as part of the public utility sector. The street and highway lighting forecast reflects the impacts of the company's LED lighting program.

The seven energy models described above, plus the effects of PV and EV related energy, and an exogenous interruptible and phosphate forecast, are added together to arrive at the total retail energy sales forecast. A line loss factor is applied to the energy sales forecast to produce the retail net energy for load forecast.

In summary, the SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels, gives estimates of weather sensitivity that varies over time, as well as estimates trend adjustments.

4. Peak Demand Multiregression Model

After the retail net energy for load forecast is complete, it is integrated into the peak demand model as an independent variable along with weather variables. The energy variable represents the long-term economic and appliance trend impacts. To stabilize the peak demand data series and improve model accuracy, the volatility of the phosphate load is removed. To further stabilize the data, the peak demand models project on a per customer basis.

The weather variables provide the monthly seasonality to the peaks. The weather variables used are heating and cooling degree-days for both the temperature at the time of the peak and the 24-hour average on the day of the peak and day prior to the peak. By incorporating both temperatures, the model is accounting for the fact that cold/heat buildup contributes to determining the peak day.

The non-phosphate per customer kW forecast is multiplied by the final customer forecast. This result is then aggregated with a phosphate-coincident peak forecast to arrive at the final projected peak demand.

5. *Interruptible Demand and Energy Analysis*

TEC interruptible customers are relatively few in number, which has allowed the company's Sales and Marketing Department to obtain detailed knowledge of industry developments including:

- Knowledge of expansion and close-out plans;
- Familiarity with historical and projected trends;
- Personal contact with industry personnel;
- Governmental legislation;
- Familiarity with worldwide demand for phosphate products.

This department's familiarity with industry dynamics and their close working relationship with phosphate and other company representatives were used to form the basis for a survey of the interruptible customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast and the commercial/industrial interruptible rate class forecasts are based. Further inputs are provided by individual customer trend analysis and discussions with industry experts.

6. *Conservation, Load Management and Cogeneration Programs*

Conservation and Load Management demand and energy savings are forecasted for each individual program. The savings are based on a forecast of the annual number of new participants, estimated annual average energy savings per participant and estimated summer and winter average demand savings per participant. The individual forecasts are aggregated and represent the cumulative amount of DSM savings throughout the forecast horizon.

TEC retail demand and energy forecasts are adjusted downward to reflect the incremental demand and energy savings of these DSM programs.

TEC has developed conservation, load management and cogeneration programs to achieve five major objectives:

1. Defer expansion, particularly production plant construction.
2. Reduce marginal fuel cost by managing energy usage during higher fuel cost periods.
3. Provide customers with some ability to control energy usage and decrease energy costs.
4. Pursue the cost-effective accomplishment of the FPSC ten-year demand and energy goals for the residential and commercial/industrial sectors.
5. Achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act (FEECA).

In 2017, TEC continued operating within the 2015-2024 DSM Plan, which supports the approved FPSC goals, which are reasonable, beneficial and cost-effective to all customers as required by the FEECA. The company also received Commission approval of one new DSM program (ENERGY STAR Program for New Multi-Family Residences) and added a modification to include electric vehicle driver's education within the existing Energy Education, Awareness and Agency Outreach Program. Also in 2017, the company initiated the process with all the other FEECA utilities to start the development of the technical potential study, which will support the 2020-2029 DSM Plan. The following is a list that briefly describes the company's DSM programs:

1. Energy Audits - a "how to" information and analysis guide for customers. Six types of audits are available to TEC customers; four types are for residential customers and two types are for commercial/industrial customers.

2. Residential Ceiling Insulation – a rebate program that encourages existing residential customers to install additional ceiling insulation in existing homes.

3. Residential Duct Repair – a rebate program that encourages residential customers to repair leaky duct work of central air conditioning systems in existing homes.

4. Residential Electronically Commutated Motor (ECM) – a rebate program that encourages residential customers to replace their existing HVAC air handler motor with an ECM.

5. Energy Education, Awareness and Agency Outreach - a program that provides opportunities for engaging and educating groups of customers and students on energy-efficiency and conservation as well as electric vehicles (at participating high schools) in an organized setting. Participants are provided with an energy savings kit, which includes energy saving devices and supporting information appropriate for the audience.

6. Energy Star for New Multi-Family Residences - a rebate program that encourages the construction of new multi-family residences to meet the requirements to achieve the ENERGY STAR certified apartments and condominium label.

7. Energy Star for New Homes - a rebate program that encourages residential customers to construct residential dwellings that qualify for the Energy Star Award by achieving efficiency levels greater than current Florida building code baseline practices.

8. Residential Heating and Cooling – a rebate program that encourages residential customers to install high-efficiency residential heating and cooling equipment in existing homes.

9. Neighborhood Weatherization – a program that provides for the installation of energy efficient measures for qualified low-income customers.

10. Residential Price Responsive Load Management (Energy Planner) – a program that reduces weather-sensitive loads through an innovative price responsive rate used to encourage residential customers to make behavioral or equipment usages changes by pre-programming HVAC, water heating and pool pumps.

11. Residential Wall Insulation – a rebate program that encourages existing residential customers to install additional wall insulation in existing homes.

12. Residential Window Replacement – a rebate program that encourages existing residential customers to install window upgrades in existing homes.

13. Commercial Ceiling Insulation – a rebate program that encourages commercial and industrial customers to install additional ceiling insulation in existing commercial structures.

14. Commercial Chiller – a rebate program that encourages commercial and industrial customers to install high efficiency chiller equipment.

15. Cogeneration – an incentive program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, meet their own electrical requirements and/or sell their surplus to the company.

16. Conservation Value – a rebate program that encourages commercial and industrial customers to invest in energy efficiency and conservation measures that are not sanctioned by other commercial programs.

17. Cool Roof – a rebate program that encourages commercial and industrial customers to install a cool roof system above conditioned spaces.

18. Commercial Cooling – a rebate program that encourages commercial and industrial customers to install high efficiency direct expansion commercial air conditioning cooling equipment.

19. Demand Response – a turn-key incentive program for commercial and industrial customers to reduce their demand for electricity in response to market signals.

20. Commercial Duct Repair – a rebate program that encourage existing commercial and industrial customers to repair leaky ductwork of central air-conditioning systems in existing commercial and industrial facilities.

21. Commercial Electronically Commutated Motors (ECM) - a rebate program that encourages commercial and industrial customers to replace their existing air handler motors or refrigeration fan motors with an ECM.

22. Industrial Load Management – an incentive program whereby large industrial customers allow for the interruption of their facility or portions of their facility electrical load.

23. Lighting Conditioned Space – a rebate program that encourages commercial and industrial customers to invest in more efficient lighting technologies in existing conditioned areas of commercial and industrial facilities.

24. Lighting Non-Conditioned Space – a rebate program that encourages commercial and industrial customers to invest in more efficient lighting technologies in existing non-conditioned areas of commercial and industrial facilities.

25. Lighting Occupancy Sensors – a rebate program that encourages commercial and industrial customers to install occupancy sensors to control commercial lighting systems.

26. Commercial Load Management – an incentive program that encourages commercial and industrial customers to allow for the control of weather-sensitive heating, cooling and water heating systems to reduce the associated weather sensitive peak.

27. Refrigeration Anti-Condensate Control – a rebate program that encourages commercial and industrial customers to install anti-condensate equipment sensors and control within refrigerated door systems.

28. Standby Generator – an incentive program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.

29. Thermal Energy Storage - a rebate program that encourages commercial and industrial customers to install an off-peak air conditioning system.

30. Commercial Wall Insulation – a rebate program that encourages commercial and industrial customers to install wall insulation in existing commercial and industrial structures.

31. Commercial Water Heating – a rebate program that encourages commercial and industrial customers to install high efficiency water heating systems.

32. Conservation Research and Development (R&D) – a program that allows for the exploration of DSM measures that have insufficient data on the cost-effectiveness of the measure and the potential impact to TEC and its ratepayers.

The programs listed above were developed to meet FPSC demand and energy goals established in Docket No. 130201-EI, Order No. PSC-14-0696-FOF-EU, Issued December 16, 2014. The 2017 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

TEC developed a Monitoring and Evaluation (M&E) plan in response to FPSC requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources.

The M&E plan has its focus on two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give TEC insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

TABLE III-1

Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals

Savings at the Generator

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	12.3	2.6	473.1%	10.8	1.1	981.8%	21.2	1.8	1177.8%
2016	7.7	4.1	187.8%	5.1	1.6	318.8%	13.2	3.5	377.1%
2017	6.9	5.2	132.0%	4.7	2.2	212.0%	14.9	4.8	310.9%
2018		6.5			2.7			6.1	
2019		7.6			3.1			6.9	
2020		7.6			3.3			7.4	
2021		8.0			3.3			7.7	
2022		7.4			3.0			6.9	
2023		6.8			2.9			6.3	
2024		6.1			2.5			5.5	

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	8.1	1.2	675.0%	11.7	1.7	688.2%	12.5	3.9	320.5%
2016	2.9	1.3	223.1%	4.4	2.5	176.0%	17.8	6.0	296.7%
2017	9.2	1.6	578.1%	10.4	2.7	385.5%	30.2	8.0	377.9%
2018		1.7			3.3			9.2	
2019		1.6			3.3			9.9	
2020		1.7			3.5			10.3	
2021		1.9			3.6			10.4	
2022		1.9			3.3			10.2	
2023		1.8			3.5			9.9	
2024		1.7			3.2			9.6	

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	20.4	3.8	536.8%	22.5	2.8	803.6%	33.7	5.7	591.2%
2016	10.6	5.4	196.3%	9.5	4.1	231.7%	31.0	9.5	326.3%
2017	16.1	6.8	237.0%	15.1	4.9	307.6%	45.2	12.8	352.8%
2018		8.2			6.0			15.3	
2019		9.2			6.4			16.8	
2020		9.3			6.8			17.7	
2021		9.9			6.9			18.1	
2022		9.3			6.3			17.1	
2023		8.6			6.4			16.2	
2024		7.8			5.7			15.1	

BASE CASE FORECAST ASSUMPTIONS

RETAIL LOAD

Numerous assumptions are inputs to the MetrixND models, of which the more significant ones are listed below.

1. Population and Households
2. Commercial, Industrial and Governmental Employment
3. Commercial, Industrial and Governmental Output
4. Real Household Income
5. Price of Electricity
6. Appliance Efficiency Standards
7. Weather

1. Population and Households

Florida and Hillsborough County population forecasts are the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Moody's Analytics supply population projections for Hillsborough County and Florida comparisons. BEBR's population growth for Hillsborough County was used to project future growth patterns in residential customers for the period of 2018-2027. The average annual population growth rate is expected to be 1.8%.

2. Commercial, Industrial and Governmental Employment

Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. Over the next ten years (2018-2027), employment is assumed to rise at a 1.2% average annual rate within Hillsborough County. Moody's Analytics supplies employment projections for the non-residential models.

3. Commercial, Industrial and Governmental Output

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Output for the entire employment sector within Hillsborough County is assumed to rise at a 3.8% average annual rate from 2018-2027. Moody's Analytics supplies output projections.

4. Real Household Income

Moody's Analytics supplies the assumptions for Hillsborough County's real household income growth. During 2018-2027, real household income for Hillsborough County is expected to increase at a 2.1% average annual rate.

5. *Price of Electricity*

Forecasts for the price of electricity by customer class are supplied by TEC's Regulatory Affairs Department.

6. *Appliance Efficiency Standards*

Another factor influencing energy consumption is the movement toward more efficient appliances such as heat pumps, refrigerators, lighting and other household appliances. The forces behind this development include market pressures for greater energy-saving devices, legislation, rules, and the appliance efficiency standards enacted by the state and federal governments. Also influencing energy consumption is the customer saturation levels of appliances. The saturation trend for heating appliances is increasing through time; however, overall electricity consumption actually declines over time as less efficient heating technologies (room heating and furnaces) are replaced with more efficient technologies (heat pumps). Similarly, cooling equipment saturation will continue to increase, but be offset by heat pump and central air conditioning efficiency gains.

Improvements in the efficiency of other non-weather related appliances also help to lower electricity consumption. Although there is an increasing saturation trend of electronic equipment and appliances in households throughout the forecast period, it does not offset the efficiency gains from lighting and appliances.

7. *Weather*

The weather assumptions are the most difficult to project. Therefore, historical data is the major determinant in developing temperature profiles. For example, monthly profiles used in calculating energy consumption are based on twenty years of historical data. In addition, the temperature profiles used in projecting the winter and summer system peak are based on an examination of the minimum and maximum temperatures for the past twenty years plus the temperatures on peak days for the past twenty years.

HIGH AND LOW SCENARIO FOCUS ASSUMPTIONS

The base case scenario is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy scenarios represent alternatives to the company's base case outlook. Compared to the base case, the expected economic growth rates are 0.5 percent higher in the high scenario and 0.5 percent lower in the low scenario.

HISTORY AND FORECAST OF ENERGY USE

A history and forecast of energy consumption by customer classification are shown in Schedules 2.1 - 2.3 in Chapter IV.

1. Retail Energy

For 2018-2027, retail energy sales are projected to rise at a 1.0% annual rate. The major contributors to growth include the residential and commercial categories, increasing at an annual rate of 1.5% and 0.9%, respectively.

2. Wholesale Energy

TEC has no scheduled firm wholesale power sales at this time.

HISTORY AND FORECAST OF PEAK LOADS

Historical, base, high, and low scenario forecasts of peak loads for the summer and winter seasons are presented in Schedules 3.1 and 3.2, respectively. For the period of 2018-2027, TEC's base retail firm peak demand is expected to increase at an average annual rate of 1.3% in the summer and 1.4% in the winter.

Chapter III

INTEGRATED RESOURCE PLANNING PROCESSES

TEC's IRP process was designed to evaluate demand-side and supply-side resources on a comparable and consistent basis to satisfy future demand and energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders.

The process incorporates a reliability analysis to determine timing of future needs and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. Initially, a demand and energy forecast, which excludes incremental energy efficiency and conservation programs, is developed. Then, without any incremental energy efficiency and conservation, an interim supply plan based on the system requirements is developed based upon this new demand and energy forecast. This interim supply plan is used to identify the basis for the next potential avoided unit(s). The data from this interim supply plan provides the baseline data that is used to perform a comprehensive cost effectiveness analysis of the energy efficiency and conservation programs.

Once this comprehensive analysis is complete, and the cost-effective energy efficiency and conservation programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the energy efficiency and conservation programs and supply-side resources.

The cost-effectiveness of energy efficiency and demand-response programs is based on the following standard Commission tests: the Rate Impact Measure test (RIM), the Total Resource Cost test (TRC), and the Participants Cost test (PCT). Using the FPSC's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are used in this analysis. All measures that pass the RIM and PCT tests in the energy efficiency and demand response analysis are considered for utility program adoption.

Each adopted measure is quantified into its coincident summer and winter peak kW reduction contribution and its annual kWh savings and is reflected in the demand and energy forecast. TEC evaluates and reports energy efficiency and demand response measures that comports with Rule 25-17.008, F.A.C., the FPSC's prescribed cost-effectiveness methodology.

Generating resources to be considered are determined through an alternative technology screening analysis, which is designed to determine the economic viability of a wide range of generating technologies for the TEC service area.

The technologies that pass the screening are included in a supply-side analysis that examines various supply-side alternatives for meeting future capacity requirements.

TEC uses a computer model developed by ABB, System Optimizer (SO), to evaluate supply-side resources. SO utilizes a mixed integer linear program (MILP) to develop an estimate of the timing and type of supply-side resources for capacity additions that would most economically meet the system demand and energy requirements. The objective function of the MILP is to compare all feasible combinations of generating unit additions, satisfy the specified reliability criteria, and determine the schedule and addition with the lowest total present worth revenue requirements.

Detailed cost analyses for each of the top ranked resource plans are performed using the Planning & Risk (PaR) production cost model, also developed by ABB. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources in our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

The result of the IRP process provides TEC with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, TEC previously converted Polk Units 2-5 to Polk 2 CC, a natural gas combined cycle unit with the addition of a steam turbine that went into service in January 2017. The company's expansion plans include the addition of 600 MW_{AC} of solar PV through 2021 in accordance with the Solar Base Rate Adjustment (SoBRA) which was approved as part of the stipulation and settlement agreement in late 2017. TEC intends to modernize Big Bend by first installing simple cycle peaking combustion turbines and initiating the repowering of unit 1 and retirement of unit 2 by 2021. These combustion turbines will be integrated into a natural gas combined cycle unit by 2023 using the repowered unit 1 steam turbine. The company also plans to add a simple cycle combustion turbine in 2023 and another simple cycle combustion turbine in 2026. All these changes to the expansion plan are shown in Schedule 8.1.

TEC will continue to assess competitive purchase power agreements that may replace or delay the scheduled units. Such optimizations must achieve the overall objective of providing reliable power in the most cost effective manner.

FINANCIAL ASSUMPTIONS

TEC makes numerous financial assumptions as part of the preparation for its TYSP process. These assumptions are based on the current financial status of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code 25-6, an amount for AFUDC is recorded by the company during the construction phase of each capital project that meets the requirements. This rate is approved by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.
- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the TYSP.
- The financing cost rates reflect the incremental cost of capital associated with each of the

sources of long-term financing.

- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.
- Depreciation represents the annual cost to amortize the total original investment in a plant over its useful life less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the TYSP represents the average expected life for that type of asset.

EXPANSION PLAN ECONOMICS AND FUEL FORECAST

The overall economics and cost-effectiveness of the plan were analyzed using TEC's IRP process. As part of this process, TEC evaluated various planning and operating alternatives against expected operations, with the objective to: meet compliance requirements in the most cost-effective and reliable manner, maximize operational flexibility and minimize total costs.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine the options that were the most feasible overall. Those alternatives that failed to meet the qualitative and quantitative considerations were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in more detailed economic analyses.

TEC forecasts base case natural gas, coal, and oil fuel commodity prices by analyzing current market prices and price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, PIRA Energy Group, Coal Daily, Inside FERC, and Platt's Oilgram. For natural gas, coal and oil prices, the company produces both high and low fuel price projections, which represent alternative forecasts to the company's base case outlook.

TAMPA ELECTRIC'S RENEWABLE ENERGY PROGRAMS

The Renewable Energy Program was signed into effect by the Commission in Docket No. 060678-EG, Order No. PSC-06-1063-TRF-EG, issued December 26, 2006. TEC's Renewable Energy Program offers residential, commercial and industrial customers the opportunity to purchase 200 kWh renewable energy "blocks" for their home or business. In 2009, TEC added a new portion to the program which allows residential, commercial and industrial customers the opportunity to purchase renewable energy to power a specific event. This enables a family, business or venue to make a statement about their commitment to the environment and to renewable energy.

Through December 2017, TEC's Renewable Energy Program has approximately 1,600 customers purchasing over 2,500 blocks of renewable energy each month. In addition, there have been over 200 one-time blocks purchased for large, public and private events in Tampa in 2017. In 2018, TEC is refreshing the program marketing materials to focus on increasing one-time and recurring solar block purchases from all customer classes. TEC's solar portfolio has reached a level that the energy needed for the Renewable Energy Program is entirely generated from local solar sources.

In 2018, Tampa Electric's Renewable Energy Program is installing a 75 kW array at the Florida Conservation and Technology Center (FCTC). This community site is a collaborative effort between TEC, the Florida Fish & Wildlife Conservation Commission (FWC), and the Florida Aquarium, which will provide many more opportunities to educate Tampa Electric customers and visitors on the benefits of solar energy, in addition to the other seven local solar arrays the program has funded.

TEC continually analyzes renewable energy alternatives with the objective to integrate them into our resource portfolio. The company's renewable-generation portfolio is a mix of various solar technologies, including seven smaller, company-owned photovoltaic (PV) arrays totaling 116 KW_{AC} and three large-scale PV systems totaling 22.4 MW_{AC}.

The smaller, community-sited PV arrays are installed at the Museum of Science and Industry, Walker Middle and Middleton High schools, TEC's Manatee Viewing Center, Tampa's Lowry Park Zoo, the Florida Aquarium and LEGOLAND® Florida's Imagination Zone. To further educate the public on the benefits of renewable energy, the installations at these facilities include signage and interactive displays that were built to provide a hands-on experience to engage visitors' interest and provide education in solar technology.

The company completed the installation of its first large-scale solar facility at Tampa International Airport in 2015. The solar PV array, sized at 1.6 MW_{AC}, can produce enough electricity to power more than 250 homes. In 2016, TEC completed its second large-scale PV system – a 1.4 MW_{AC} array at LEGOLAND® Florida in Winter Haven. This array was constructed on a shade canopy in the park's preferred parking lot and generates enough energy to power more than 200 homes. TEC owns both large-scale solar PV facilities and the electricity they produce goes to the grid to benefit TEC's renewable energy program customers. In February 2017, TEC placed in operation a 19.4 MW_{AC} array which is located at the company's Big Bend Station and has the capacity to power nearly 3,300 homes.

As market conditions continue to change and technology improves in this sector, renewable alternatives, such as solar, become more cost effective to our customers. Through December 2017, more than 1,744 residential customers installed PV systems on their homes and another 123 commercial or industrial customers installed PV systems on their businesses. The number of home solar arrays in 2017 is 150% of what they were in 2016. At the end of 2017, 1867 TEC customers with PV arrays on their home or business had a total connected capacity of almost 19 MW_{DC}.

In addition, TEC has announced plans to install up to an additional 600 MW_{AC} of utility scale solar PV distributed across multiple sites by 2021 as part of the SoBRA approved in 2017.

GENERATING UNIT PERFORMANCE ASSUMPTIONS

TEC's generating unit performance assumptions are used to evaluate long-range system operating costs associated with integrated resource plans. Generating units are characterized by several different performance parameters. These parameters include capacity, heat rate, unit derations, planned maintenance days, and unplanned outage rates.

The unit performance projections are based on historical data trends, engineering judgment, time since last planned outage, and recent equipment performance. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on a repetitive pattern.

The forecasted outage schedule is based on unit-specific maintenance needs, material lead-time, labor availability, and the need to supply our customers with power in the most economical manner. Unplanned outage rates are projected based on an average of three years of historical data, future expectations, and any necessary adjustments to account for current unit conditions.

GENERATION RELIABILITY CRITERIA

TEC calculates reserve margin in two ways to measure reliability of the generating system. The company utilizes a minimum 20 percent reserve margin with a minimum contribution of 7 percent supply-side resources. TEC's approach to calculating percent reserves are consistent with the agreement that is outlined in the Commission approved Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, issued December 22, 1999. The calculation of the minimum 20 percent reserve margin employs an industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and solar capacity unavailable at the time of peak demand, and contracted unit sales) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100. Capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from TEC's available capacity.

TEC's supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the firm peak demand and interruptible and load management loads.

SUPPLY-SIDE RESOURCES PROCUREMENT PROCESS

TEC will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply-side resources, as well as suppliers of equipment and services, will be identified using various database resources and competitive bid evaluations, and will be used in developing award recommendations to management.

This process will allow for future supply-side resources to be supplied from self-build, purchased power, or asset purchases. Consistent with company practice, bidders will be encouraged to propose incentive arrangements that promote development and implementation of cost savings and process-improvement recommendations.

TRANSMISSION PLANNING - CONSTRAINTS AND IMPACTS

The TEC transmission system supports the reliable delivery of required capacity and energy to TEC's retail and wholesale customers. Transmission Planning studies are performed annually to evaluate the performance of the TEC transmission system with the results of the studies varying due to refinements in load projections, planning criteria, generation plans and operating flexibility. This involves the use of steady-state load flow, short circuit and transient stability programs to model various contingency situations, 3-Phase Fault and Single Line-Ground Fault analysis that may occur to determine if the TEC transmission system meets the reliability criteria. Simulations of normal system conditions, as well as single and select multiple contingency events, are performed during system peak and off-peak load levels, under summer and/or winter conditions. Based on existing studies (ex: internal expansion, joint utility, operating, Florida Reliability Coordinating Council (FRCC) Long Range Study, FRCC Planning and Extreme Events Stability Analysis, FRCC Summer Assessment, FRCC Winter Assessment and other miscellaneous studies) and TEC's current transmission construction program, TEC anticipates no transmission constraints that violate the criteria as described in the Transmission Planning Reliability Criteria section of this document.

TRANSMISSION PLANNING RELIABILITY CRITERIA

1. Transmission

TEC developed the transmission planning reliability criteria, as described in the FERC Form 715 filing, to assess and test the strength and limits of the transmission system, while meeting the load responsibility and being able to move bulk power between and among other electric systems. TEC has adopted the transmission planning criteria outlined in the FRCC's *FRCC Regional Transmission Planning Process*. The FRCC's transmission planning criteria are consistent with the North American Electric Reliability Corporation (NERC) Reliability Standards.

In general, the NERC Reliability Standards state the transmission system will remain stable, within the applicable thermal and voltage rating limits, without cascading outages, under normal, single and select multiple contingency conditions. In addition to the FRCC criteria, TEC utilizes company-specific planning criteria for normal system operation and contingency operation, along with a Facility Rating Methodology and Facility Interconnection Requirements document available at https://www.oasis.oati.com/TEC/index.html.

The transmission planning reliability criteria are used as guidelines for proposing transmission system expansion and/or improvement projects, however they are not absolute rules for system expansion. These criteria are used to alert planners of potential transmission system capacity limitations. Engineering analysis is used in all stages of the planning process to weigh the impact of system deficiencies, the likelihood of the triggering contingency, and the viability of any operating options. Only by carefully researching each potential planning criteria violation can a final evaluation of available transmission capacity be made.

2. Available Transmission Transfer Capability (ATC) Criteria

TEC adheres to the ATC calculation methodology described in the Attachment C of the *Tampa Electric Company Open Access Transmission Tariff FERC Electric Tariff, Fourth Revised Volume No. 4* document, accessible at https://www.oasis.oati.com/woa/docs/TEC/TECdocs/TransmissionTariff.pdf, as well as the principles contained in the NERC Reliability Standards relating to ATC calculations. Members of the FRCC, including TEC, have formed the Florida Transmission Capability Determination Group in an effort to provide ATC values to the regional electric market that are transparent, coordinated, timely and accurate.

TRANSMISSION SYSTEM PLANNING ASSESSMENT PRACTICES

TEC's transmission system planning assessment practices are developed according to the TEC and NERC Reliability Standards to ensure a reliable system is planned that demonstrates adequacy within TEC's footprint to meet present and future system needs. The Reliability Standards require that the TEC transmission system be planned such that it will remain stable within the applicable facility ratings and voltage rating limits and without cascading outages under normal system conditions, as well as single and select multiple contingency events.

TEC performs transmission studies independently, collaboratively with other utilities, and as part of the FRCC to determine if the system meets the criteria. The studies involve the use of steady-state power flows, transient stability analyses, short circuit assessments and various other assessments to ensure adequate system performance.

1. Base Case Operating Conditions

The TEC transmission system can support peak and off-peak system load levels while meeting the criteria as described in the Transmission Planning Reliability Criteria section of this document.

2. Single Contingency Planning Criteria

The TEC transmission system is designed to support any single event outage of a transmission circuit, autotransformer, generator, or shunt device (including FRCC studies of Category P1 and P2-1 events) at a variety of load levels while meeting the criteria as described in the Transmission Planning Reliability Criteria section of this document.

3. Multiple Contingency Planning Criteria

Select double contingencies (including FRCC studies of Category P2-2 through P7 events) involving two or more Bulk Electric System (BES) transmission system elements out of service are analyzed at a variety of load levels. The TEC transmission system is designed such that double contingencies meet the criteria as described in the Transmission Planning Reliability Standards Criteria section of this document

4. *Transmission Construction and Upgrade Plans*

A specific list of the proposed directly associated transmission construction projects corresponding with the proposed generating facilities can be found in Chapter V, Schedule 10. This list represents the latest BES transmission construction related to the generation expansion on Schedule 8 and 9. However, due to the timing of this document in relationship to the company's internal planning schedule, this plan may change in the future. The current transmission construction and upgrade plan for the planning horizon does not require any electric utility system lines to be certified under the Transmission Line Siting Act (403.52-403.536, F.S.).

ENERGY EFFICIENCY, CONSERVATION, AND ENERGY SAVINGS DURABILITY

TEC ensures that DSM programs the company offers are directly monitorable and yield measurable results. The achievements and durability of energy savings from the company's conservation and load management programs is validated by several methods. First, TEC has established a monitoring and evaluation process where historical analysis validates the energy savings. These include:

1. Periodic system load reduction analysis for price responsive load management (Energy Planner), Commercial industrial load management and Commercial demand response to confirm and verify the accuracy of TEC's load reduction estimation formulas.

2. Billing energy usage and demand analysis of participants in certain energy efficiency and conservation programs as compared to control groups.

3. Analysis of DOE2 modeling of various program participants.

4. End-use monitoring and evaluation of projects and programs.

5. Specific metering of loads under control to determine the actual demand and energy savings in commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response.

Second, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Specifically, those programs that promote the installation of energy-efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, wall insulation, window replacements, air distribution system repairs, DX commercial cooling units, chiller replacements, water heating replacements, and ECM motor upgrades) have program standards that require the new equipment to be installed in a permanent manner thus ensuring their durability.

Chapter IV

FORECAST OF ELECTRIC POWER, DEMAND AND ENERGY CONSUMPTION

Tables in Schedules 2 through 4 reflect three different levels of load forecasting: base case, high case, and low case. The expansion plan is developed using the base case load forecast and is reflected on Schedules 5 through 9. This forecast band best represents the current economic conditions and the long-term impacts to TEC's service territory.

Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 3.1: History and Forecast of Summer Peak Demand (Base, High & Low)

Schedule 3.2: History and Forecast of Winter Peak Demand (Base, High & Low)

Schedule 3.3: History and Forecast of Annual Net Energy for Load (Base, High & Low)

Schedule 4: Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month (Base, High & Low)

Schedule 5: History and Forecast of Fuel Requirements

Schedule 6.1: History and Forecast of Net Energy for Load by Fuel Source in GWh

Schedule 6.2: History and Forecast of Net Energy for Load by Fuel Source as a Percent

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,238,951	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,256,118	2.6	8,395	603,594	13,909	6,185	71,143	86,937
2013	1,276,410	2.6	8,470	613,206	13,812	6,090	71,966	84,619
2014	1,301,887	2.6	8,656	623,846	13,875	6,142	72,647	84,548
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
2016	1,352,797	2.5	9,187	646,221	14,217	6,310	74,313	84,911
2017	1,379,302	2.6	9,029	659,387	13,693	6,362	74,998	84,830
2018	1,408,464	2.6	9,263	673,808	13,747	6,545	76,005	86,110
2019	1,436,883	2.5	9,419	687,116	13,708	6,597	76,726	85,987
2020	1,465,951	2.5	9,560	700,815	13,641	6,636	77,261	85,888
2021	1,493,987	2.5	9,695	714,059	13,577	6,679	77,726	85,936
2022	1,521,576	2.5	9,864	727,119	13,566	6,736	78,339	85,988
2023	1,548,669	2.5	10,004	739,964	13,520	6,803	79,010	86,103
2024	1,575,078	2.5	10,146	752,501	13,483	6,878	79,567	86,438
2025	1,600,735	2.5	10,293	764,692	13,461	6,952	80,002	86,895
2026	1,625,683	2.5	10,448	776,555	13,455	7,032	80,405	87,459
2027	1,649,944	2.5	10,601	788,098	13,452	7,114	80,830	88,017

Notes:
December 31, 2017 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.1

Forecast of Energy Consumption and Number of Customers by Customer Class High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2018	1,415,360	2.6	9,322	677,099	13,768	6,558	76,152	86,117
2019	1,450,996	2.6	9,541	693,848	13,751	6,624	77,026	86,001
2020	1,487,604	2.6	9,747	711,143	13,706	6,677	77,721	85,911
2021	1,523,492	2.6	9,950	728,132	13,664	6,736	78,353	85,966
2022	1,559,244	2.6	10,189	745,084	13,675	6,808	79,140	86,027
2023	1,594,803	2.6	10,402	761,967	13,652	6,891	79,991	86,153
2024	1,631,173	2.6	10,619	778,681	13,638	6,983	80,733	86,498
2025	1,667,145	2.6	10,844	795,185	13,637	7,076	81,360	86,966
2026	1,702,638	2.6	11,080	811,492	13,654	7,175	81,962	87,539
2027	1,737,687	2.6	11,316	827,607	13,674	7,277	82,591	88,107

Notes:
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

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Schedule 2.1

Forecast of Energy Consumption and Number of Customers by Customer Class Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2018	1,401,567	2.5	9,203	670,516	13,725	6,532	75,859	86,103
2019	1,422,840	2.5	9,298	680,416	13,665	6,571	76,427	85,973
2020	1,444,509	2.5	9,375	690,587	13,576	6,595	76,805	85,867
2021	1,464,913	2.5	9,446	700,192	13,490	6,624	77,108	85,906
2022	1,484,640	2.5	9,548	709,503	13,457	6,666	77,554	85,949
2023	1,503,652	2.4	9,620	718,495	13,389	6,717	78,054	86,053
2024	1,521,775	2.4	9,692	727,081	13,330	6,775	78,434	86,377
2025	1,538,955	2.4	9,768	735,229	13,285	6,832	78,689	86,825
2026	1,555,245	2.4	9,849	742,964	13,257	6,895	78,908	87,380
2027	1,570,679	2.4	9,927	750,297	13,231	6,959	79,146	87,926

Notes:
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting** GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,494	1,207,299	0	74	1,761	18,564
2012	2,001	1,537	1,302,171	0	75	1,756	18,412
2013	2,027	1,564	1,295,916	0	75	1,756	18,418
2014	1,901	1,572	1,208,831	0	75	1,752	18,526
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	2,024	1,608	1,259,094	0	0	1,771	19,186
2018	1,964	1,633	1,202,128	0	0	1,773	19,544
2019	1,927	1,646	1,170,773	0	0	1,769	19,713
2020	1,947	1,657	1,174,953	0	0	1,769	19,911
2021	1,970	1,666	1,182,386	0	0	1,775	20,119
2022	1,890	1,676	1,127,708	0	0	1,784	20,274
2023	1,914	1,685	1,135,787	0	0	1,797	20,518
2024	1,934	1,693	1,142,162	0	0	1,812	20,769
2025	1,944	1,700	1,143,372	0	0	1,827	21,016
2026	1,808	1,708	1,058,765	0	0	1,842	21,131
2027	1,831	1,715	1,067,633	0	0	1,858	21,404

Notes:
December 31, 2017 Status
*Average of end-of-month customers for the calendar year.
**Sales for Street and Highway Lighting from 2017 forward are now included with Other Sales to Public Authorities.
Values shown may be affected due to rounding.

Schedule 2.2

Forecast of Energy Consumption and
Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting** GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2018	1,967	1,634	1,203,747	0	0	1,773	19,620
2019	1,934	1,647	1,174,149	0	0	1,769	19,869
2020	1,957	1,659	1,179,663	0	0	1,769	20,150
2021	1,984	1,669	1,188,932	0	0	1,774	20,444
2022	1,908	1,679	1,136,438	0	0	1,784	20,689
2023	1,936	1,689	1,146,458	0	0	1,796	21,026
2024	1,961	1,698	1,154,732	0	0	1,811	21,374
2025	1,976	1,706	1,158,210	0	0	1,826	21,722
2026	1,844	1,714	1,076,109	0	0	1,841	21,941
2027	1,872	1,721	1,087,752	0	0	1,857	22,322

Notes:
*Average of end-of-month customers for the calendar year.
**Sales for Street and Highway Lighting are now included with Other Sales to Public Authorities.
Values shown may be affected due to rounding.

Schedule 2.2

Forecast of Energy Consumption and
Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting** GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2018	1,960	1,633	1,200,402	0	0	1,773	19,468
2019	1,920	1,645	1,167,258	0	0	1,770	19,558
2020	1,936	1,655	1,169,825	0	0	1,770	19,676
2021	1,956	1,663	1,175,988	0	0	1,775	19,801
2022	1,871	1,672	1,119,243	0	0	1,785	19,869
2023	1,891	1,681	1,125,101	0	0	1,798	20,025
2024	1,907	1,688	1,129,861	0	0	1,812	20,187
2025	1,914	1,695	1,128,989	0	0	1,828	20,341
2026	1,773	1,702	1,041,766	0	0	1,843	20,361
2027	1,791	1,708	1,048,743	0	0	1,859	20,537

Notes:
*Average of end-of-month customers for the calendar year.
**Sales for Street and Highway Lighting are now included with Other Sales to Public Authorities.
Values shown may be affected due to rounding.

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Base Case

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
2010	305	1,149	20,667	7,827	670,991
2011	93	642	19,298	7,869	675,799
2012	69	839	19,320	7,962	684,236
2013	0	760	19,177	7,999	694,735
2014	0	789	19,315	8,095	706,161
2015	0	1,098	20,105	8,168	718,713
2016	9	930	20,173	8,353	730,503
2017	2	1,110	20,298	8,698	744,690
2018	0	956	20,500	8,612	760,058
2019	0	964	20,677	8,672	774,160
2020	0	973	20,885	8,734	788,467
2021	0	984	21,103	8,795	802,246
2022	0	991	21,266	8,852	815,986
2023	0	1,004	21,521	8,912	829,571
2024	0	1,016	21,785	8,976	842,736
2025	0	1,028	22,044	9,041	855,435
2026	0	1,034	22,165	9,106	867,774
2027	0	1,048	22,452	9,171	879,814

Notes:
December 31, 2017 Status
*Includes sales to Duke Energy Florida (DEF), Wauchula (WAU), Ft. Meade (FTM), St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
Contract ended with FTM on 12/31/08, DEF on 2/31/11, WAU on 9/31/11, STC on 12/31/2012, FPL on 12/31/12, and RCID on 12/31/10. RCID contract from 2016 to 2017.
**Utility Use and Losses include accrued sales.
***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
****Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.3

Forecast of Energy Consumption and Number of Customers by Customer Class High Case

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other Customers	(6) Total Customers
2018	0	959	20,580	8,625	763,510
2019	0	971	20,840	8,698	781,219
2020	0	985	21,135	8,773	799,296
2021	0	1,000	21,443	8,848	817,002
2022	0	1,012	21,701	8,919	834,822
2023	0	1,028	22,054	8,993	852,640
2024	0	1,046	22,420	9,071	870,183
2025	0	1,063	22,784	9,150	887,401
2026	0	1,074	23,014	9,230	904,398
2027	0	1,092	23,414	9,310	921,229

Notes:

*Utility Use and Losses include accrued sales.
**Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
***Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

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Schedule 2.3

Forecast of Energy Consumption and
Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other Customers	Total Customers
2018	0	952	20,420	8,599	756,607
2019	0	956	20,514	8,645	767,133
2020	0	962	20,638	8,694	777,741
2021	0	968	20,769	8,741	787,704
2022	0	972	20,841	8,784	797,513
2023	0	980	21,005	8,829	807,059
2024	0	988	21,174	8,878	816,081
2025	0	995	21,336	8,928	824,541
2026	0	996	21,357	8,977	832,551
2027	0	1,005	21,542	9,026	840,177

Notes:
*Utility Use and Losses include accrued sales.
**Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
***Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

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Schedule 3.1

History and Forecast of Summer Peak Demand (MW)
Base Case

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation***	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2008	4,276	148	4,128	143	69	84	53	55	3,723
2009	4,316	136	4,180	120	54	90	58	59	3,799
2010	4,171	118	4,053	73	33	97	75	65	3,710
2011	4,130	28	4,102	109	48	103	75	68	3,699
2012	4,089	15	4,073	133	45	111	86	71	3,627
2013	4,072	0	4,072	131	39	122	89	77	3,614
2014	4,270	0	4,270	170	36	132	91	83	3,757
2015	4,245	0	4,245	111	21	143	98	87	3,784
2016	4,403	15	4,388	138	0	150	101	92	3,907
2017	4,373	5	4,368	110	0	155	100	98	3,905
2018	4,383	0	4,383	115	0	160	100	98	3,910
2019	4,441	0	4,441	109	0	165	100	101	3,966
2020	4,502	0	4,502	109	0	170	100	105	4,018
2021	4,564	0	4,564	110	0	176	101	108	4,069
2022	4,619	0	4,619	98	0	181	101	111	4,128
2023	4,685	0	4,685	98	0	187	102	114	4,184
2024	4,750	0	4,750	98	0	192	102	117	4,241
2025	4,814	0	4,814	97	0	197	103	120	4,296
2026	4,862	0	4,862	81	0	203	103	124	4,352
2027	4,929	0	4,929	81	0	208	103	127	4,410

Notes:

December 31, 2017 Status
2010 and 2016 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with FTM on 12/31/08, DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract with RCID from 2016 to 2017.
***Includes Energy Planner program.
Values shown may be affected due to rounding.

Schedule 3.1

Forecast of Summer Peak Demand (MW)
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale	Retail *	Interruptible	Residential Load Management	Residential Conservation**	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2018	4,400	0	4,400	115	0	160	100	98	3,927
2019	4,476	0	4,476	109	0	165	100	101	4,001
2020	4,556	0	4,556	109	0	170	100	105	4,072
2021	4,637	0	4,637	110	0	176	101	108	4,142
2022	4,713	0	4,713	98	0	181	101	111	4,222
2023	4,800	0	4,800	98	0	187	102	114	4,299
2024	4,886	0	4,886	98	0	192	102	117	4,377
2025	4,973	0	4,973	97	0	197	103	120	4,455
2026	5,044	0	5,044	81	0	203	103	124	4,534
2027	5,135	0	5,135	81	0	208	103	127	4,616

Notes:

*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
Values shown may be affected due to rounding.

Schedule 3.1

Forecast of Summer Peak Demand (MW)
Low Case

(1) Year	(2) Total *	(3) Wholesale	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation**	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2018	4,366	0	4,366	115	0	160	100	98	3,893
2019	4,406	0	4,406	109	0	165	100	101	3,931
2020	4,449	0	4,449	109	0	170	100	105	3,965
2021	4,493	0	4,493	110	0	176	101	108	3,998
2022	4,528	0	4,528	98	0	181	101	111	4,037
2023	4,574	0	4,574	98	0	187	102	114	4,073
2024	4,618	0	4,618	98	0	192	102	117	4,109
2025	4,662	0	4,662	97	0	197	103	120	4,144
2026	4,688	0	4,688	81	0	203	103	124	4,178
2027	4,733	0	4,733	81	0	208	103	127	4,214

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
Values shown may be affected due to rounding.

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Schedule 3.2

History and Forecast of Winter Peak Demand (MW)
Base Case

(1) Year	(2) Total *	(3) Wholesale **	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation***	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2007/08	4,405	152	4,253	120	130	456	53	52	3,443
2008/09	4,696	67	4,629	181	105	462	75	52	3,754
2009/10	5,195	122	5,073	117	109	470	75	56	4,246
2010/11	4,695	120	4,575	140	88	480	75	58	3,735
2011/12	4,081	15	4,066	103	68	487	83	58	3,267
2012/13	3,764	0	3,764	130	65	501	90	61	2,918
2013/14	3,876	0	3,876	61	63	512	97	64	3,079
2014/15	4,195	0	4,195	79	44	521	96	65	3,390
2015/16	4,025	0	4,025	145	13	533	96	67	3,171
2016/17	3,749	0	3,749	137	0	541	96	70	2,905
2017/18	4,903	0	4,903	94	0	548	95	70	4,096
2018/19	4,972	0	4,972	88	0	555	96	71	4,162
2019/20	5,043	0	5,043	88	0	563	97	72	4,223
2020/21	5,111	0	5,111	88	0	571	97	73	4,282
2021/22	5,172	0	5,172	77	0	579	98	74	4,344
2022/23	5,245	0	5,245	77	0	587	98	75	4,408
2023/24	5,318	0	5,318	78	0	595	99	76	4,470
2024/25	5,388	0	5,388	77	0	603	100	77	4,531
2025/26	5,443	0	5,443	60	0	611	100	78	4,594
2026/27	5,515	0	5,515	60	0	619	101	79	4,656

Notes:

December 31, 2017 Status
2011/2012 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with FTM on 12/31/08, DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract with RCID from 2016 to 2017.
***Includes energy planner program.
Values shown may be affected due to rounding.

Schedule 3.2

Forecast of Winter Peak Demand (MW)
High Case

(1) Year	(2) Total *	(3) Wholesale	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation**	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2017/18	4,921	0	4,921	94	0	548	95	70	4,114
2018/19	5,010	0	5,010	88	0	555	96	71	4,200
2019/20	5,100	0	5,100	88	0	563	97	72	4,280
2020/21	5,188	0	5,188	88	0	571	97	73	4,359
2021/22	5,270	0	5,270	77	0	579	98	74	4,442
2022/23	5,365	0	5,365	77	0	587	98	75	4,528
2023/24	5,461	0	5,461	78	0	595	99	76	4,613
2024/25	5,555	0	5,555	77	0	603	100	77	4,698
2025/26	5,634	0	5,634	60	0	611	100	78	4,785
2026/27	5,731	0	5,731	60	0	619	101	79	4,872

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
Values shown may be affected due to rounding.

Schedule 3.2

Forecast of Winter Peak Demand (MW)
Low Case

(1) Year	(2) Total *	(3) Wholesale	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation**	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2017/18	4,884	0	4,884	94	0	548	95	70	4,077
2018/19	4,935	0	4,935	88	0	555	96	71	4,125
2019/20	4,987	0	4,987	88	0	563	97	72	4,167
2020/21	5,036	0	5,036	88	0	571	97	73	4,207
2021/22	5,076	0	5,076	77	0	579	98	74	4,248
2022/23	5,128	0	5,128	77	0	587	98	75	4,291
2023/24	5,179	0	5,179	78	0	595	99	76	4,331
2024/25	5,228	0	5,228	77	0	603	100	77	4,371
2025/26	5,260	0	5,260	60	0	611	100	78	4,411
2026/27	5,309	0	5,309	60	0	619	101	79	4,450

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
Values shown may be affected due to rounding.

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Schedule 3.3

History and Forecast of Annual Net Energy for Load (GWh)
Base Case

(1) Year	(2) Total*	(3) Residential Conservation**	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale ***	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load **** Factor %
2008	19,632	431	212	18,990	752	909	20,650	56.8
2009	19,449	444	231	18,774	191	978	19,943	54.4
2010	19,923	458	251	19,213	305	1,149	20,667	50.5
2011	19,296	474	259	18,564	93	642	19,298	55.6
2012	19,178	493	273	18,412	69	839	19,320	56.3
2013	19,225	513	294	18,418	0	760	19,177	56.5
2014	19,377	546	305	18,526	0	789	19,315	54.4
2015	19,890	568	315	19,006	0	1,098	20,105	57.2
2016	20,153	588	331	19,234	9	930	20,173	55.2
2017	20,141	602	353	19,186	2	1,110	20,298	56.2
2018	20,502	611	346	19,544	0	956	20,500	54.6
2019	20,688	624	352	19,713	0	964	20,677	54.3
2020	20,905	636	358	19,911	0	973	20,885	53.9
2021	21,132	649	364	20,119	0	984	21,103	53.9
2022	21,306	662	370	20,274	0	991	21,266	53.7
2023	21,568	674	376	20,518	0	1,004	21,521	53.6
2024	21,838	687	382	20,769	0	1,016	21,785	53.4
2025	22,104	699	388	21,016	0	1,028	22,044	53.5
2026	22,237	712	394	21,131	0	1,034	22,165	53.2
2027	22,529	724	400	21,404	0	1,048	22,452	53.2

Notes:

December 31, 2017 Status

*Includes residential and commercial/industrial conservation.

**Includes Energy Planner program.

***Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with FTM on 12/31/08, DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract with RCID from 2016 to 2017.

****Load Factor is the ratio of total system average load to peak demand.

Values shown may be affected due to rounding.

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Schedule 3.3

Forecast of Annual Net Energy for Load (GWh)
High Case

(1) Year	(2) Total*	(3) Residential Conservation**	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load *** Factor %
2018	20,578	611	346	19,620	0	959	20,580	54.6
2019	20,844	624	352	19,869	0	971	20,840	54.3
2020	21,144	636	358	20,150	0	985	21,135	53.9
2021	21,456	649	364	20,444	0	1,000	21,443	53.9
2022	21,721	662	370	20,689	0	1,012	21,701	53.7
2023	22,076	674	376	21,026	0	1,028	22,054	53.5
2024	22,443	687	382	21,374	0	1,046	22,420	53.3
2025	22,809	699	388	21,722	0	1,063	22,784	53.4
2026	23,047	712	394	21,941	0	1,074	23,014	53.1
2027	23,447	724	400	22,322	0	1,092	23,414	53.1

Notes:

*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

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Schedule 3.3

Forecast of Annual Net Energy for Load (GWh)
Low Case

(1) Year	(2) Total*	(3) Residential Conservation**	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load *** Factor %
2018	20,426	611	346	19,468	0	952	20,420	54.6
2019	20,534	624	352	19,558	0	956	20,514	54.3
2020	20,670	636	358	19,676	0	962	20,638	54.0
2021	20,813	649	364	19,801	0	968	20,769	54.0
2022	20,901	662	370	19,869	0	972	20,841	53.8
2023	21,076	674	376	20,025	0	980	21,005	53.7
2024	21,255	687	382	20,187	0	988	21,174	53.5
2025	21,429	699	388	20,341	0	995	21,336	53.6
2026	21,467	712	394	20,361	0	996	21,357	53.3
2027	21,662	724	400	20,537	0	1,005	21,542	53.3

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

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Schedule 4
Base Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2017 Actual		2018 Forecast		2019 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,138	1,479	4,285	1,516	4,346	1,526
February	2,994	1,297	3,550	1,338	3,598	1,346
March	3,077	1,486	3,368	1,478	3,411	1,487
April	3,837	1,639	3,548	1,575	3,595	1,587
May	3,890	1,889	3,761	1,834	3,810	1,850
June	4,005	1,849	4,046	1,990	4,098	2,009
July	4,120	2,023	4,079	2,057	4,128	2,078
August	4,074	2,103	4,125	2,086	4,175	2,107
September	3,953	1,867	3,852	1,940	3,897	1,960
October	3,818	1,773	3,640	1,736	3,681	1,753
November	2,974	1,420	3,042	1,411	3,075	1,423
December	2,940	1,472	3,878	1,537	3,925	1,549
TOTAL		20,298		20,500		20,677

Notes:

December 31, 2017 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
**Values shown may be affected due to rounding.

Schedule 4
High Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2017 Actual		2018 Forecast		2019 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,138	1,479	4,303	1,522	4,384	1,538
February	2,994	1,297	3,565	1,343	3,628	1,356
March	3,077	1,486	3,382	1,484	3,440	1,499
April	3,837	1,639	3,563	1,581	3,625	1,599
May	3,890	1,889	3,777	1,841	3,842	1,864
June	4,005	1,849	4,063	1,998	4,133	2,025
July	4,120	2,023	4,096	2,066	4,162	2,095
August	4,074	2,103	4,142	2,094	4,210	2,124
September	3,953	1,867	3,868	1,948	3,929	1,977
October	3,818	1,773	3,655	1,743	3,711	1,767
November	2,974	1,420	3,054	1,417	3,099	1,434
December	2,940	1,472	3,894	1,543	3,958	1,561
TOTAL		20,298		20,580		20,840

Notes:

December 31, 2017 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
**Values shown may be affected due to rounding.

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Schedule 4
Low Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2017 Actual		2018 Forecast		2019 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,138	1,479	4,266	1,510	4,309	1,514
February	2,994	1,297	3,535	1,333	3,568	1,336
March	3,077	1,486	3,354	1,473	3,383	1,476
April	3,837	1,639	3,534	1,570	3,565	1,575
May	3,890	1,889	3,745	1,827	3,778	1,836
June	4,005	1,849	4,030	1,982	4,064	1,993
July	4,120	2,023	4,062	2,049	4,093	2,061
August	4,074	2,103	4,108	2,077	4,140	2,090
September	3,953	1,867	3,836	1,932	3,865	1,944
October	3,818	1,773	3,626	1,729	3,651	1,739
November	2,974	1,420	3,030	1,406	3,050	1,413
December	2,940	1,472	3,863	1,532	3,893	1,537
TOTAL		20,298		20,421		20,514

Notes:

December 31, 2017 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
**Values shown may be affected due to rounding.

Schedule 5

History and Forecast of Fuel Requirements
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements	Unit	Actual 2016	Actual 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	3,005	2,279	1,762	1,552	1,474	1,249	1,347	566	1,148	1,314	1,224	1,533
(3)	Residual	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)	CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)	GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)	D	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	1000 BBL	1	0	0	0	0	0	0	0	0	0	0	0
(9)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)	CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)	GT	1000 BBL	1	0	0	0	0	0	0	0	0	0	0	0
(12)	D	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	1000 MCF	77,896	100,445	108,691	106,754	107,664	111,478	110,013	115,546	109,203	108,473	110,590	109,127
(14)	ST	1000 MCF	8,736	8,445	9,587	8,701	8,169	2,652	1,707	812	1,490	1,687	1,568	1,853
(15)	CC	1000 MCF	59,525	91,202	95,032	95,467	97,064	105,083	102,021	112,393	105,831	104,725	106,526	104,611
(16)	GT	1000 MCF	9,635	798	4,072	2,586	2,431	3,743	6,285	2,341	1,882	2,061	2,496	2,663
(17)	Other (Specify)													
(18)	PC	1000 Ton	393	380	366	432	433	396	432	423	396	432	432	395

Notes:
Values shown may be affected due to rounding.
All values exclude ignition.

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Schedule 6.1

History and Forecast of Net Energy for Load by Fuel Source
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources	Unit	Actual 2016	Actual 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(1)	Annual Firm Interchange	GWh	193	122	161	0	0	0	0	0	0	0	0	0
(2)	Nuclear	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal	GWh	7,667	4,949	3,950	3,463	3,256	2,705	2,997	1,283	2,574	2,944	2,752	3,430
(4)	Residual	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(5)	ST	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)	CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)	GT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)	D	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(10)	ST	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)	CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(12)	GT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(13)	D	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	GWh	10,129	13,685	14,911	14,756	14,876	15,756	15,503	17,457	16,536	16,334	16,668	16,379
(15)	ST	GWh	899	744	817	742	677	212	141	51	120	139	128	165
(16)	CC	GWh	8,381	12,871	13,733	13,787	13,986	15,162	14,714	17,198	16,249	16,012	16,317	15,976
(17)	GT	GWh	849	70	361	227	213	382	648	208	167	183	223	238
(18)	Renewable	GWh	3	45	139	976	1272	1422	1416	1410	1408	1399	1393	1387
(19)	Solar	GWh	3	45	139	976	1272	1422	1416	1410	1408	1399	1393	1387
(20)	Other (Specify)													
(21)	PC	GWh	1,100	1,064	1,033	1,220	1,224	1,118	1,220	1,195	1,119	1,220	1,220	1,115
(22)	Net Interchange	GWh	842	244	216	172	167	12	40	86	58	57	41	50
(23)	Purchased Energy from Non-Utility Generators	GWh	237	188	90	90	90	90	90	90	90	90	90	90
(24)	Net Energy for Load	GWh	20,173	20,298	20,500	20,677	20,885	21,103	21,266	21,521	21,785	22,044	22,165	22,452

Notes:

Line (22) includes energy purchased from Non-Renewable and Renewable resources.

Values shown may be affected due to rounding.

Schedule 6.2

History and Forecast of Net Energy for Load by Fuel Source
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources	Unit	Actual 2016	Actual 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(1)	Annual Firm Interchange	%	1.0	0.6	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(2)	Nuclear	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	Coal	%	38.0	24.4	19.3	16.7	15.6	12.8	14.1	6.0	11.8	13.4	12.4	15.3
(4)	Residual	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)	ST	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)	CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	GT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	D	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Distillate	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	ST	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)	CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)	GT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)	D	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	%	50.2	67.4	72.7	71.4	71.2	74.7	72.9	81.1	75.9	74.1	75.2	73.0
(15)	ST	%	4.5	3.7	4.0	3.6	3.2	1.0	0.7	0.2	0.6	0.6	0.6	0.7
(16)	CC	%	41.5	63.4	67.0	66.7	67.0	71.8	69.2	79.9	74.6	72.6	73.6	71.2
(17)	GT	%	4.2	0.3	1.8	1.1	1.0	1.8	3.0	1.0	0.8	0.8	1.0	1.1
(18)	Renewable	%	0.0	0.2	0.7	4.7	6.1	6.7	6.7	6.6	6.5	6.3	6.3	6.2
(19)	Solar	%	0.0	0.2	0.7	4.7	6.1	6.7	6.7	6.6	6.5	6.3	6.3	6.2
(20)	Other (Specify)													
(21)	PC	%	5.5	5.2	5.0	5.9	5.9	5.3	5.7	5.6	5.1	5.5	5.5	5.0
(22)	Net Interchange	%	4.2	1.2	1.1	0.8	0.8	0.1	0.2	0.4	0.3	0.3	0.2	0.2
(23)	Purchased Energy from													
(24)	Non-Utility Generators	%	1.2	0.9	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
(25)	Net Energy for Load	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Notes:

Line (22) includes energy purchased from Non-Renewable and Renewable resources.

Values shown may be affected due to rounding.

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Chapter V

FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility changes and additions shown in Schedule 8.1 integrate energy efficiency and conservation programs and generating resources to provide economical, reliable service to TEC's customers. Various energy resource plan alternatives, comprised of a mixture of generating technologies, purchased power, and cost-effective energy efficiency and conservation programs, are developed to determine this plan. These alternatives are combined with existing resources and analyzed to determine the resource options which best meets TEC's future system demand and energy requirements. A detailed discussion of TEC's integrated resource planning process is included in Chapter III.

The results of the IRP process provide TEC with a cost-effective plan that maintains system reliability and environmental requirements while considering technology, availability, dispatch ability, and lead times for construction. To cost effectively meet the expected system demand and energy requirements over the next ten years, solar PV, intermediate, and peaking resources are needed. In September 2018, TEC will add 144.7 MW_{AC} of solar PV generation. In subsequent years, the company will install over 450 MW_{AC} of additional solar PV, intermediate resources by modernizing Big Bend Power Station through the repowering of unit 1 to a 2x1 combined cycle unit and retiring unit 2, and peaking capacity from simple cycle combustion turbines. These peaking units will be installed in 2023 and 2026, respectively. The operating and cost parameters are shown in Schedule 9.

TEC will compare viable purchased power options as an alternative and/or enhancements to planned unit additions, conservation, and load management. At a minimum, the purchased power must have firm transmission service and firm fuel transportation to support firm reserve margin criteria for reliability. Assumptions and information that impact the plan are discussed in the following sections and in Chapter III.

COGENERATION

In 2018, TEC plans for 331 MW of cogeneration capacity operating in its service area.

Table IV-I 2018 Cogeneration Capacity Forecast	Capacity (MW)
Self-service [1]	268
Firm to Tampa Electric	0
As-available to Tampa Electric	7
Export to other systems	56
Total	331

[1] Capacity and energy that cogenerators produce to serve their own internal load requirements

FIRM INTERCHANGE SALES AND PURCHASES

Currently, TEC has one long-term firm purchase power agreement. Below is the contract for capacity and energy:

- 121 MW purchase from Quantum Pasco Power through December 2018

FUEL REQUIREMENTS

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2. TEC currently uses a generation portfolio consisting mainly of solid fuels and natural gas for its energy requirements. TEC has firm transportation contracts with the Florida Gas Transmission Company and Gulfstream Natural Gas System LLC for delivery of natural gas to Big Bend, Bayside, and Polk. As shown in Schedule 6.2, in 2018, coal and petcoke will fuel 24.3% of the net energy for load and natural gas will fuel 72.7%. The remaining net energy for load is served by solar PV as well as firm, non-firm, and non-utility generator purchases. Some of the company's generating units also have dual-fuel (i.e., natural gas or oil) capability, which enhances system reliability.

ENVIRONMENTAL CONSIDERATIONS

Air Quality

TEC continually strives to reduce emissions from its generating facilities. Since 1998, TEC greatly reduced annual sulfur dioxides, nitrogen oxides, particulate matter and mercury emissions as a result of the agreement with the Florida Department of Environmental Protection and the agreement with the U.S. Environmental Protection Agency in a Consent Decree. TEC fulfilled all commitments of the agreements and the motion to terminate the Consent Decree was granted on November 22, 2013. TEC's major addition of solar generation through 2021 will continue the company's transformation into a cleaner, more sustainable energy company. TEC's major activities to increase pollution control and decrease emissions include:

- Improvement of the Big Bend electrostatic precipitators
- The installation of natural gas-fired igniters at Big Bend Station will continue to provide opportunities to augment coal-fired operation and further reduce emissions during startup and normal operation.
- The Polk Power Station combined-cycle project. This improved system reliability and further reduced emissions system-wide.
- The SoBRA agreement enables the company to significantly reduce its carbon emissions profile and its dependence on carbon-based fuels by installing 600 MW_{AC} of photovoltaic single axis tracking solar generation.

TEC will continue to reduce emissions through project enhancements and best operation and maintenance work practices. However, the company recognizes that environmental regulations continue to change. As these regulations evolve, they will impact both cost and operations.

Water Quality

The final 316(b) rule became effective in October 2014 and seeks to reduce impingement and entrainment at cooling water intakes. This rule affects both Big Bend and Bayside Power Stations, since both withdraw cooling water from waters of the U.S. The full impact of the new regulations will be determined by the results of the study elements performed to comply with the rule as well as the actual requirements of the state regulatory agencies.

FDEP's numeric nutrient regulations are effective and may potentially impact the discharge from the Polk Power Station cooling water reservoir in the future. The established nitrogen allocations by Tampa Bay Nitrogen Management Consortium for both Bayside and Big Bend Power Stations are expected to meet the numeric nutrient criteria in Tampa Bay.

The final Effluent Limitations Guidelines (ELG) were published on November 3, 2015. The ELGs establish limits for wastewater discharges from flue gas desulfurization (FGD) processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals, gasification processes, and flue gas mercury controls. New limits will require new treatment technology at Big Bend Station and potentially require new treatment at Polk Power Station.

Solid Waste

The Coal Combustion Residuals Rule (CCR) became effective on October 19, 2015. The Big Bend Unit #4 Economizer Ash Ponds and the converted Units 1-3 slag fines pond are covered by this rule. The slag pond will be cleaned out and lined in 2018 -2019 to allow for continued storm water storage. Planning is underway to close the Economizer Ponds by removing and disposing of the CCRs offsite and restoring the site to natural grade. TEC is also planning to retire the South Gypsum Storage Area in 2018-2019 by removing and processing the CCRs for beneficial in 2018-2019. This CCR unit is not regulated by the CCR Rule. There are no regulated CCR units at Polk or Bayside Power Stations.

Schedule 7.1

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
							Reserve Margin Before Maintenance			Reserve Margin After Maintenance	
Year	Installed Capacity MW	Firm * Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	MW	% of Peak	Scheduled** Maintenance MW	MW	% of Peak
2018	4,815	121	0	0	4,936	3,911	1,025	26%	13	1,012	26%
2019	5,227	0	0	0	5,227	3,966	1,261	32%	211	1,049	26%
2020	5,367	0	0	0	5,367	4,018	1,349	34%	279	1,070	27%
2021	5,306	0	0	0	5,306	4,070	1,236	30%	303	933	23%
2022	5,306	0	0	0	5,306	4,129	1,177	29%	303	875	21%
2023	5,681	0	0	0	5,681	4,184	1,496	36%	303	1,193	29%
2024	5,681	0	0	0	5,681	4,241	1,440	34%	303	1,137	27%
2025	5,681	0	0	0	5,681	4,297	1,383	32%	303	1,080	25%
2026	5,910	0	0	0	5,910	4,352	1,558	36%	303	1,255	29%
2027	5,910	0	0	0	5,910	4,410	1,500	34%	303	1,197	27%

Notes:

* Includes purchase power agreement (PPA) with Quantum Pasco Power of 121 MW through 2018.

** Includes solar capacity unavailable at time of peak.

Values shown may be affected due to rounding.

Schedule 7.2

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Installed Capacity MW	Firm * Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled** Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2017-18	5,218	121	0	0	5,339	4,096	1,244	30%	22	1,221	30%
2018-19	5,630	0	0	0	5,630	4,163	1,467	35%	434	1,033	25%
2019-20	5,770	0	0	0	5,770	4,223	1,546	37%	574	973	23%
2020-21	5,819	0	0	0	5,819	4,283	1,536	36%	623	913	21%
2021-22	5,729	100	0	0	5,829	4,344	1,485	34%	623	862	20%
2022-23	6,064	0	0	0	6,064	4,408	1,656	38%	623	1,033	23%
2023-24	6,064	0	0	0	6,064	4,470	1,594	36%	623	971	22%
2024-25	6,064	0	0	0	6,064	4,531	1,533	34%	623	909	20%
2025-26	6,309	0	0	0	6,309	4,594	1,715	37%	623	1,092	24%
2026-27	6,309	0	0	0	6,309	4,656	1,653	35%	623	1,029	22%

Notes:

* Includes purchase power agreement (PPA) with Quantum Pasco Power of 121 MW through 2018.

** Includes solar capacity unavailable at time of peak.

Values shown may be affected due to rounding.

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Schedule 8.1

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.		Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	Winter MW	Status
Balm Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	09/18	*	74,400	74.4	74.4	P
Payne Creek Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	09/18	*	70,300	70.3	70.3	P
Lithia Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	1/19	*	74,500	74.5	74.5	P
Grange Hall Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	1/19	*	61,000	61.1	61.1	P
Peace Creek Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	1/19	*	57,000	56.6	56.6	P
Bonnie Mine Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	1/19	*	34,000	34.5	34.5	P
Mountain View Solar**	1	Pasco County	PV	SOLAR	NA	NA	NA	-	1/19	*	55,000	55.1	55.1	P
Wimauma Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	1/20	*	74,500	74.5	74.5	P
Alafia Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	1/20	*	50,000	50.3	50.3	P
Lake Hancock Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	1/21	*	50,000	49.6	49.6	P
Big Bend CT 5***	5M	Big Bend	GT	NG	NA	PL	NA	08/19	06/21	*	*	360	392	P
Big Bend CT 6***	6M	Big Bend	GT	NG	NA	PL	NA	08/19	06/21	*	*	360	392	P
Big Bend ST 1	1M	Big Bend	ST	NG	NA	PL	NA	06/20	01/23	*	*	335	335	P
Future CT 1	1	*	GT	NG	NA	PL	NA	01/20	01/23	*	*	229	245	P
Future CT 2	2	*	GT	NG	NA	PL	NA	01/23	01/26	*	*	229	245	P

Notes:

* Undetermined
** Solar MW values reflect seasonal capacity values, not available capacity at time of peak.
*** Net capability will be restricted to 330 MW summer / 350 MW winter until being placed into combined cycle mode in 2023.

Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.

Schedule 9
(Page 1 of 15)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Balm Solar	
(2)	Net Capability		
	A. Summer	74.4	MW-ac
	B. Winter	74.4	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	June 2017	
	B. Commercial In-Service Date	September 2018	
(5)	Fuel		
	A. Primary Fuel	Solar	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	N/A	
(7)	Cooling Method	N/A	
(8)	Total Site Area	+544 Acres	
(9)	Construction Status	In progress	
(10)	Certification Status	N/A	
(11)	Status with Federal Agencies	N/A	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF)	N/A	
	Forced Outage Factor (FOF)	N/A	
	Equivalent Availability Factor (EAF)	N/A	
	Resulting Capacity Factor (2019)	26 % (1st Full Yr Operation)	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost[3] (In-Service Year $/kW)	1,479.54	
	Direct Construction Cost ($/kW)	1,450.13	
	AFUDC[2] Amount ($/kW)	29.41	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.17	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.11	

[1] w/o Land
[2] Based on the current AFUDC rate of 6.46%
[3] Total installed cost includes transmission interconnection
[4] Construction schedule includes engineering design and permitting

Schedule 9
(Page 2 of 15)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Payne Creek Solar	
(2)	Net Capability		
	A. Summer	70.3	MW-ac
	B. Winter	70.3	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	June 2017	
	B. Commercial In-Service Date	September 2018	
(5)	Fuel		
	A. Primary Fuel	Solar	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	N/A	
(7)	Cooling Method	N/A	
(8)	Total Site Area	+503 Acres	
(9)	Construction Status	In progress	
(10)	Certification Status	N/A	
(11)	Status with Federal Agencies	N/A	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF)	N/A	
	Forced Outage Factor (FOF)	N/A	
	Equivalent Availability Factor (EAF)	N/A	
	Resulting Capacity Factor (2019)	27 % (1st Full Yr Operation)	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost[3] (In-Service Year $/kW)	1,324.18	
	Direct Construction Cost ($/kW)	1,292.95	
	AFUDC[2] Amount ($/kW)	31.23	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.17	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.10	

[1] w/o Land
[2] Based on the current AFUDC rate of 6.46%
[3] Total installed cost includes transmission interconnection
[4] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Lithia Solar	
(2)	Net Capability		
	A. Summer	74.5	MW-ac
	B. Winter	74.5	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	June 2017	
	B. Commercial In-Service Date	January 2019	
(5)	Fuel		
	A. Primary Fuel	Solar	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	N/A	
(7)	Cooling Method	N/A	
(8)	Total Site Area	+580 Acres	
(9)	Construction Status	Planned	
(10)	Certification Status	N/A	
(11)	Status with Federal Agencies	N/A	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF)	N/A	
	Forced Outage Factor (FOF)	N/A	
	Equivalent Availability Factor (EAF)	N/A	
	Resulting Capacity Factor (2019)	27 % (1st Full Yr Operation)	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost[3] (In-Service Year $/kW)	1,467.15	
	Direct Construction Cost ($/kW)	1,436.66	
	AFUDC[2] Amount ($/kW)	30.49	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.34	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.11	

[1] w/o Land
[2] Based on the current AFUDC rate of 6.46%
[3] Total installed cost includes transmission interconnection
[4] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Grange Hall Solar	
(2)	Net Capability		
	A. Summer	61.1	MW-ac
	B. Winter	61.1	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	June 2017	
	B. Commercial In-Service Date	January 2019	
(5)	Fuel		
	A. Primary Fuel	Solar	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	N/A	
(7)	Cooling Method	N/A	
(8)	Total Site Area	+447 Acres	
(9)	Construction Status	Planned	
(10)	Certification Status	N/A	
(11)	Status with Federal Agencies	N/A	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF)	N/A	
	Forced Outage Factor (FOF)	N/A	
	Equivalent Availability Factor (EAF)	N/A	
	Resulting Capacity Factor (2019)	26 % (1st Full Yr Operation)	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost[3] (In-Service Year $/kW)	1,392.90	
	Direct Construction Cost ($/kW)	1,363.83	
	AFUDC[2] Amount ($/kW)	29.07	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.34	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.12	

[1] w/o Land
[2] Based on the current AFUDC rate of 6.46%
[3] Total installed cost includes transmission interconnection
[4] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Peace Creek Solar	
(2)	Net Capability		
	A. Summer	56.6	MW-ac
	B. Winter	56.6	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	September 2017	
	B. Commercial In-Service Date	January 2019	
(5)	Fuel		
	A. Primary Fuel	Solar	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	N/A	
(7)	Cooling Method	N/A	
(8)	Total Site Area	+422 Acres	
(9)	Construction Status	Planned	
(10)	Certification Status	N/A	
(11)	Status with Federal Agencies	N/A	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF)	N/A	
	Forced Outage Factor (FOF)	N/A	
	Equivalent Availability Factor (EAF)	N/A	
	Resulting Capacity Factor (2019)	26 % (1st Full Yr Operation)	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost[3] (In-Service Year $/kW)	1,478.05	
	Direct Construction Cost ($/kW)	1,448.26	
	AFUDC[2] Amount ($/kW)	29.79	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.34	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.11	

[1] w/o Land
[2] Based on the current AFUDC rate of 6.46%
[3] Total installed cost includes transmission interconnection
[4] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Bonnie Mine Solar	
(2)	Net Capability		
	A. Summer	34.5	MW-ac
	B. Winter	34.5	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	November 2017	
	B. Commercial In-Service Date	January 2019	
(5)	Fuel		
	A. Primary Fuel	Solar	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	N/A	
(7)	Cooling Method	N/A	
(8)	Total Site Area	+352 Acres	
(9)	Construction Status	Planned	
(10)	Certification Status	N/A	
(11)	Status with Federal Agencies	N/A	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF)	N/A	
	Forced Outage Factor (FOF)	N/A	
	Equivalent Availability Factor (EAF)	N/A	
	Resulting Capacity Factor (2019)	26 % (1st Full Yr Operation)	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost[3] (In-Service Year $/kW)	1,467.27	
	Direct Construction Cost ($/kW)	1,435.78	
	AFUDC[2] Amount ($/kW)	31.49	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.52	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.12	

[1] w/o Land
[2] Based on the current AFUDC rate of 6.46%
[3] Total installed cost includes transmission interconnection
[4] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Mountain View Solar
(2)	Net Capability	
	A. Summer	55.1 MW-ac
	B. Winter	55.1 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	June 2017
	B. Commercial In-Service Date	January 2019
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+345 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2019)	26 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,388.68
	Direct Construction Cost ($/kW)	1,359.53
	AFUDC[2] Amount ($/kW)	29.15
	Escalation ($/kW)	N/A
	Fixed O&M (In-Service Year $/kW – Yr)	7.52
	Variable O&M (In-Service Year $/MWh)	0.0
	K-Factor [1]	1.12

[1] w/o Land
[2] Based on the current AFUDC rate of 6.46%
[3] Total installed cost includes transmission interconnection
[4] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Wimauma Solar	
(2)	Net Capability		
	A. Summer	74.5	MW-ac
	B. Winter	74.5	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	October 2017	
	B. Commercial In-Service Date	January 2020	
(5)	Fuel		
	A. Primary Fuel	Solar	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	N/A	
(7)	Cooling Method	N/A	
(8)	Total Site Area	+500 Acres	
(9)	Construction Status	Planned	
(10)	Certification Status	N/A	
(11)	Status with Federal Agencies	N/A	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF)	N/A	
	Forced Outage Factor (FOF)	N/A	
	Equivalent Availability Factor (EAF)	N/A	
	Resulting Capacity Factor (2020)	27 % (1st Full Yr Operation)	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost[3] (In-Service Year $/kW)	1,485.02	
	Direct Construction Cost ($/kW)	1,454.38	
	AFUDC[2] Amount ($/kW)	30.64	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.34	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.11	

[1] w/o Land
[2] Based on the current AFUDC rate of 6.46%
[3] Total installed cost includes transmission interconnection
[4] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Alafia Solar	
(2)	Net Capability		
	A. Summer	50.3	MW-ac
	B. Winter	50.3	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	November 2017	
	B. Commercial In-Service Date	January 2020	
(5)	Fuel		
	A. Primary Fuel	Solar	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	N/A	
(7)	Cooling Method	N/A	
(8)	Total Site Area	+477 Acres	
(9)	Construction Status	Planned	
(10)	Certification Status	N/A	
(11)	Status with Federal Agencies	N/A	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF)	N/A	
	Forced Outage Factor (FOF)	N/A	
	Equivalent Availability Factor (EAF)	N/A	
	Resulting Capacity Factor (2020)	27 % (1st Full Yr Operation)	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost[3] (In-Service Year $/kW)	1,470.97	
	Direct Construction Cost ($/kW)	1,439.52	
	AFUDC[2] Amount ($/kW)	31.44	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.52	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.12	

[1] w/o Land
[2] Based on the current AFUDC rate of 6.46%
[3] Total installed cost includes transmission interconnection
[4] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Lake Hancock Solar	
(2)	Net Capability		
	A. Summer	49.6	MW-ac
	B. Winter	49.6	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	January 2018	
	B. Commercial In-Service Date	January 2021	
(5)	Fuel		
	A. Primary Fuel	Solar	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	N/A	
(7)	Cooling Method	N/A	
(8)	Total Site Area	+356 Acres	
(9)	Construction Status	Planned	
(10)	Certification Status	N/A	
(11)	Status with Federal Agencies	N/A	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF)	N/A	
	Forced Outage Factor (FOF)	N/A	
	Equivalent Availability Factor (EAF)	N/A	
	Resulting Capacity Factor (2021)	27 % (1st Full Yr Operation)	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost[3] (In-Service Year $/kW)	1,470.03	
	Direct Construction Cost ($/kW)	1,439.91	
	AFUDC[2] Amount ($/kW)	30.11	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.70	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.14	

[1] w/o Land
[2] Based on the current AFUDC rate of 6.46%
[3] Total installed cost includes transmission interconnection
[4] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend CT 5
(2)	Net Capability	
	A. Summer	360 MW[4]
	B. Winter	392 MW[4]
(3)	Technology Type	Combustion Turbine[3]
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	August 2019
	B. Commercial In-Service Date	June 2021
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.05
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.93
	Resulting Capacity Factor (2022)	9.2 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	9,367 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	533.17
	Direct Construction Cost ($/kW)	351.04
	AFUDC[1] Amount ($/kW)	36.37
	Escalation ($/kW)	145.76
	Fixed O&M (In-Service Year $/kW – Yr)	7.32
	Variable O&M (In-Service Year $/MWh)	2.68
	K-Factor	1.5613

[1] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection
[3] Converts to 2x1 Combined Cycle with a HRSG & Big Bend ST 1 in 2023
[4] Net capability will be restricted to 330 MW S / 350 MW W until being placed into combined cycle mode in 2023

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend CT 6
(2)	Net Capability	
	A. Summer	360 MW[4]
	B. Winter	392 MW[4]
(3)	Technology Type	Combustion Turbine[3]
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	August 2019
	B. Commercial In-Service Date	June 2021
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.05
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.93
	Resulting Capacity Factor (2022)	9.2 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	9,367 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	533.17
	Direct Construction Cost ($/kW)	351.04
	AFUDC[1] Amount ($/kW)	36.37
	Escalation ($/kW)	145.76
	Fixed O&M (In-Service Year $/kW – Yr)	7.32
	Variable O&M (In-Service Year $/MWh)	2.68
	K-Factor	1.5613

[1] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection
[3] Converts to 2x1 Combined Cycle with a HRSG & Big Bend ST 1 in 2023
[4] Net capability will be restricted to 330 MW S / 350 MW W until being placed into combined cycle mode in 2023

Schedule 9
(Page 13 of 15)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend ST 1
(2)	Net Capability	
	A. Summer	335 MW
	B. Winter	335 MW
(3)	Technology Type	Combined Cycle[3]
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	June 2020
	B. Commercial In-Service Date	January 2023
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	SCR, DLN Burners
(7)	Cooling Method	Once Through Cooling
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.05
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.93
	Resulting Capacity Factor (2023)	87.8 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	6,258 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	1,266.28
	Direct Construction Cost ($/kW)	1,037.75
	AFUDC[1] Amount ($/kW)	143.43
	Escalation ($/kW)	85.11
	Fixed O&M (In-Service Year $/kW – Yr)	6.44
	Variable O&M (In-Service Year $/MWh)	2.81
	K-Factor	1.4634

[1] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection
[3] Converts Big Bend CT 5 & 6 and HRSG's to 2x1 Combined Cycle

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future CT 1
(2)	Net Capability	
	A. Summer	229 MW
	B. Winter	245 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	January 2020
	B. Commercial In-Service Date	January 2023
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.04
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.94
	Resulting Capacity Factor (2023)	4.1 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	11,110 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	616.14
	Direct Construction Cost ($/kW)	471.31
	AFUDC[1] Amount ($/kW)	52.76
	Escalation ($/kW)	92.01
	Fixed O&M (In-Service Year $/kW – Yr)	6.33
	Variable O&M (In-Service Year $/MWh)	2.25
	K-Factor	1.5213

[1] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection

Schedule 9
(Page 15 of 15)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future CT 2
(2)	Net Capability	
	A. Summer	229 MW
	B. Winter	245 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	January 2023
	B. Commercial In-Service Date	January 2026
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.04
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.94
	Resulting Capacity Factor (2026)	2.5 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	11,123 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	661.58
	Direct Construction Cost ($/kW)	467.48
	AFUDC[1] Amount ($/kW)	56.65
	Escalation ($/kW)	137.45
	Fixed O&M (In-Service Year $/kW – Yr)	6.80
	Variable O&M (In-Service Year $/MWh)	2.42
	K-Factor	1.5213

[1] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

Units	Point of Origin and Termination	Number of Circuits	Right-of-Way (ROW)	Circuit Length **	Voltage	Anticipated In-Service Date	Anticipated Capital Investment ***	Substations	Participation with Other Utilities
Balm Solar ****	Balm - Aspen	1	ROW-TEC Owned	1	230 kV	September 2018	$2.5 Million	Balm Metering Station & Aspen Substation	None
Lithia Solar ****	Mines - Lithia - Aspen	1	ROW-TEC Owned	1	230 kV	December 2018	$3.8 Million	Lithia Metering Station, Mines & Aspen Substation	None
Alafia Solar ****	Alafia - Polk	1	New ROW required	2	230 kV	December 2019	$4.7 Million	Alafia Metering Station & Polk Substation	None
Lake Hancock Solar ****	Recker - Lake Hancock - Crews Lake	1	Not Determined	1	230 kV	December 2020	$3.4 Million	Lake Hancock Metering Station, Recker & Crews Lake Substation	None
Big Bend CT 5 ****	Big Bend CT 5 does not require any new transmission lines	-	-	-	230 kV	June 2021	****	Big Bend	None
Big Bend CT 6 ****	Big Bend CT 6 does not require any new transmission lines	-	-	-	230 kV	June 2021	****	Big Bend	None
Big Bend ST 1 ****	Big Bend ST 1 does not require any new transmission lines	-	-	-	230 kV	January 2023	****	Big Bend	None
Future CT 1	Unsited *	-	-	-	-	January 2023	-	-	-
Future CT 2	Unsited *	-	-	-	-	January 2026	-	-	-

Note:

* Specific information related to "Unsited" units unknown at this time.
** Approximate mileage listed is based on construction activity, not overall circuit length.
*** Cumulative capital investment at the in-service date. Cost included in total installed cost on Schedule 9.
**** Interconnection Requests pertaining to a Large Generating Facility have been submitted for these units. Pending completion of the Interconnection Request studies, the information provided on Schedule 10 may change.

Chapter VI

ENVIRONMENTAL AND LAND USE INFORMATION

The future generating capacity additions identified in Chapter V could occur at H.L. Culbreath Bayside Power Station, Polk Power Station, or Big Bend Power Station. The H.L. Culbreath Bayside Power Station site is located in Hillsborough County on Port Sutton Road (See Figure VI-I), Polk Power Station site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-II) and Big Bend Power Station is located in Hillsborough County on Big Bend Road (See Figure VI-III). All existing facilities are currently permitted as existing power plant sites. The new solar sites identified in Schedule 8.1 are spread across Hillsborough, Polk, and Pasco counties (See Figure VI-IV). Additional land use requirements and/or alternative site locations are currently under consideration to accommodate the addition of future solar PV generation facilities.

Figure VI-I: Site Location of H.L. Culbreath Bayside Power Station

Figure VI-II: Site Location of Polk Power Station

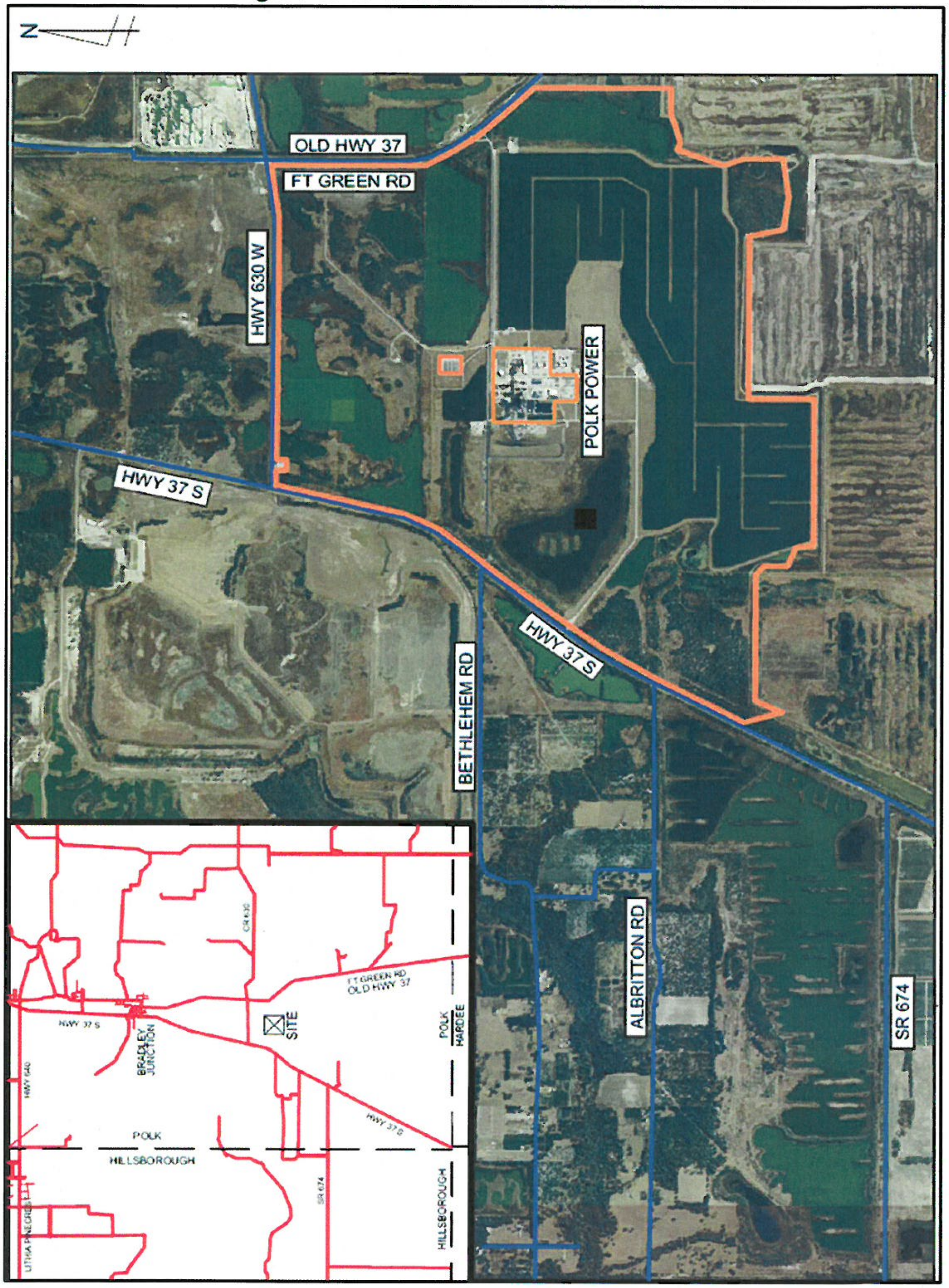

Figure VI-III: Site Location of Big Bend Power Station

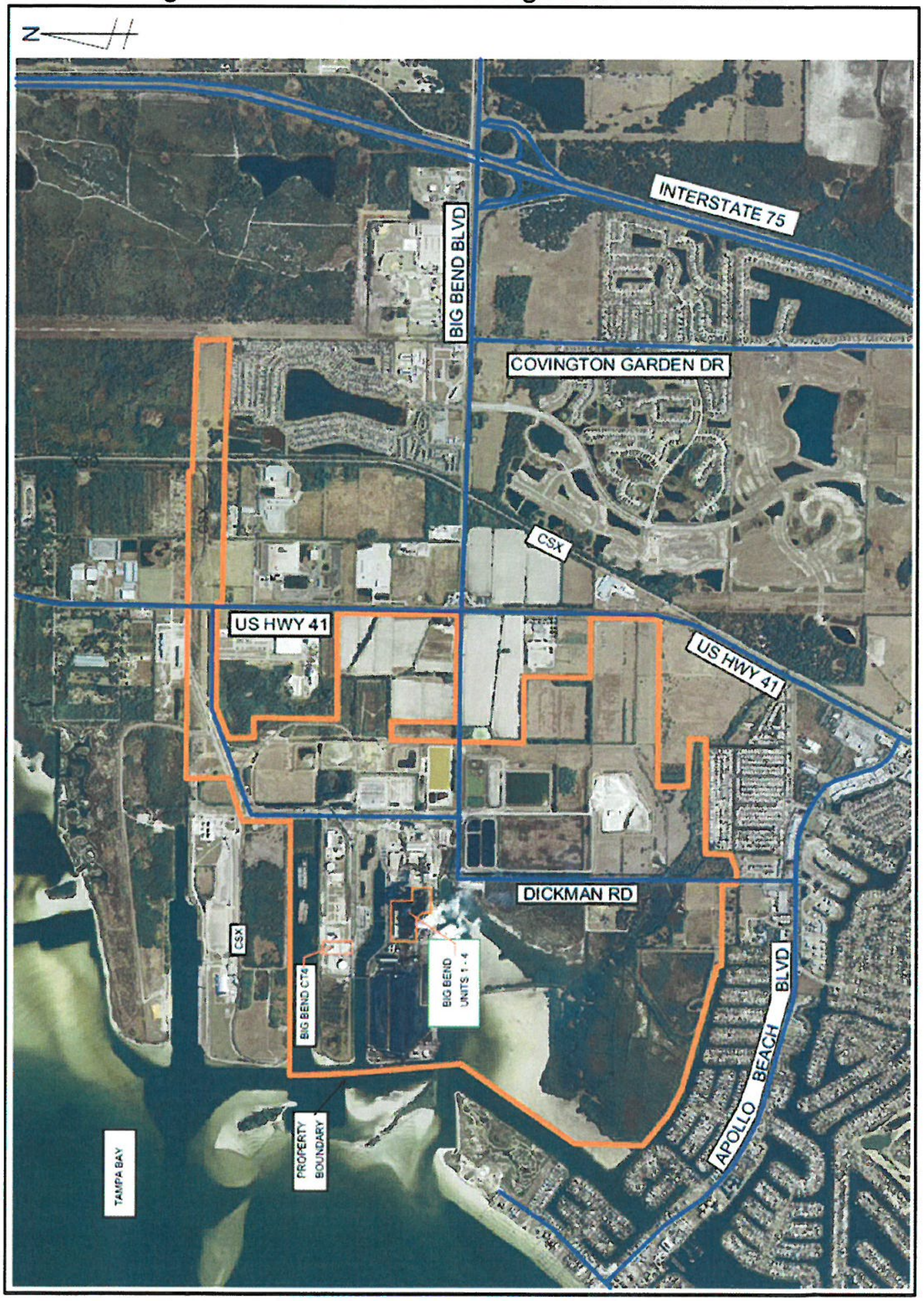

Figure VI-IV: Site Location of Future Solar Power Stations

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2. **Cost-effectiveness.** Please refer to Page 10, Lines 11-15, of the direct testimony of witness Ward. Provide the pricing information received from the shortlisted developers for the seven solar PV projects, broken out into engineering and permitting, equipment, balance of system, installation, and interconnection.

A. The requested information is attached.

REDACTED

Developer 1	Cecil B James	Holmberg	Jaymar	Little Diehl	Loop Farms	Montesco	P2
Project Output (MWac)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PV Modules	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Inverters & Transformers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Complete Substation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trackers (if applicable)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCADA/DAS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Balance of Plant	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Permitting	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Engineering (Struc/Elec/Geo Tech)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Installation (Labor, Materials, etc.)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Site Prep & Roadworks	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fencing and Gate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Interconnection	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Security cameras	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Overhead & Contingency	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Misc.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Performance Bond	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Price $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Developer 2	Cecil B James	Holmberg	Jaymar	Little Diehl	Loop Farms	Montesco	P2	Lithia
Project Output (MWac)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PV Modules	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Inverters & Transformers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Complete Substation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trackers (if applicable)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCADA/DAS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Balance of Plant	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Permitting	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Engineering (Struc/Elec/Geo Tech)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Installation (Labor, Materials, etc.)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Site Prep & Roadworks	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fencing and Gate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Interconnection	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Security cameras	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Overhead & Contingency	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Misc.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Performance Bond	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Price $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Developer 3	Cecil B James	Holmberg	Jaymar	Little Diehl	Loop Farms	Montesco	P2
Project Output (MWac)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PV Modules	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Inverters & Transformers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Complete Substation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trackers (if applicable)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCADA/DAS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Balance of Plant	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Permitting	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Engineering (Struc/Elec/Geo Tech)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Installation (Labor, Materials, etc.)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Site Prep & Roadworks	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fencing and Gate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Interconnection	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Security cameras	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Margin & Overhead	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Misc.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Performance Bond	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Price $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3. **Cost-effectiveness.** Please refer to Page 16, Lines 10-25, and Page 17, Lines 1-2, of the direct testimony of witness Ward. Provide the calculations and workpapers used to determine the projected total installed cost of each of the Second SoBRA Projects, broken down into EPC costs, development costs, third party development fees, permitting costs, land acquisition costs, taxes, utility costs to support or complete development, transmission interconnection costs, modules and equipment costs, costs associated with electrical balance of system, costs associated with structural balance of system, allowance for funds used during construction, and other traditionally allowed rate base costs. If the documents are available in Excel format, please provide them as such with all formulas intact.

A. The requested information is attached.

REDACTED

Lithia Solar	
Estimated Costs ($MM)	
Project Output (MW-ac)	**74.5**
Major Equipment, Balance of System and Development Cost[1]	**90.1**
[redacted]	
Transmission Interconnect[2]	**4.0**
Land[3]	**13.8**
Owners Costs[4]	**0.9**
Total Installed Cost ($MM)	**108.8**
AFUDC ($MM)	**2.5**
Total All-in-Cost ($MM)	**111.3**
Total ($/kW-ac)	**1,494**

[1]BOS pricing reflects contracted costs
[2]Transmission costs based on Time and Material Contract with Energy Delivery Contractor
[3]Land costs include acquisition and closing of land
[4]Owners costs include actuals and monthly forecast for remaining duration of project

Definition Table:
SCADA & DAS - Supervisory Control and Data Acquisition & Data Acquisition Systems

REDACTED

Grange Hall Solar	
Estimated Costs ($MM)	
Project Output (MW-ac)	61.1
Major Equipment, Balance of System and Development Cost[1]	73.3
[redacted]	
Transmission Interconnect[2]	4.6
Land[3]	8.4
Owners Costs[4]	0.5
Total Installed Cost ($MM)	86.8
AFUDC ($MM)	1.0
Total All-in-Cost ($MM)	87.8
Total ($/kW-ac)	1,438

[1]BOS pricing reflects contracted costs
[2]Transmission costs based on Time and Material Contract with Energy Delivery Contractor
[3]Land costs include acquisition and closing of land
[4]Owners costs include actuals and monthly forecast for remaining duration of project
[5] Includes Contractor Engineering and Development costs

Definition Table:
FTNP - Full Notice to Proceed
MV - Mid-Voltage
SUT - Step-Up Transformer

Peace Creek Solar	
Estimated Costs ($MM)	
Project Output (MW-ac)	**55.4**
Major Equipment, Balance of System and Development Cost[1]	**64.5**
[redacted]	
Transmission Interconnect[2]	**4.7**
Land[3]	**11.7**
Owners Costs[4]	**0.4**
Total Installed Cost ($MM)	**81.3**
AFUDC ($MM)	**1.4**
Total All-in-Cost ($MM)	**82.6**
Total ($/kW-ac)	**1,492**

[1]BOS pricing reflects contracted costs
[2]Transmission costs based on Time and Material Contract with Energy Delivery Contractor
[3]Land costs include acquisition and closing of land
[4]Owners costs include actuals and monthly forecast for remaining duration of project
[5] Includes Contractor Engineering and Development costs

Definition Table:
FTNP - Full Notice to Proceed
MV - Mid-Voltage
SUT- Step-Up Transformer

REDACTED

Bonnie Mine Solar Estimated Costs ($MM)	
Project Output (MW-ac)	37.5
Major Equipment, Balance of System and Development Cost[1]	48.6
[redacted]	
Transmission Interconnect[2]	0.9
Land[3]	4.3
Owners Costs[4]	0.3
Total Installed Cost ($MM)	54.1
AFUDC ($MM)	0.8
Total All-in-Cost ($MM)	54.9
Total ($/kW-ac)	1,464

[1]BOS pricing reflects contracted costs
[2]Transmission costs based on Time and Material Contract with Energy Delivery Contractor
[3]Land costs include acquisition and closing of land
[4]Owners costs includes actuals and monthly forecast for remaining duration of project

Definition Table:
SCADA & DAS - Supervisory Control and Data Acquisition and Data Acquisition Systems
GC/GR, OH - General Contingency, General Requirements, Overhead

REDACTED

Lake Hancock Solar	
Estimated Costs ($MM)	
Project Output (MW-ac)	49.5
Major Equipment, Balance of System and Development Cost[1]	60.4
[redacted]	
Transmission Interconnect[2]	4.1
Land[3]	9.1
Owners Costs[4]	0.3
Total Installed Cost ($MM)	74.0
AFUDC ($MM)	-
Total All-in-Cost ($MM)	74.0
Total ($/kW-ac)	1,494

[1]BOS pricing reflects estimated costs based on Peace Creek Solar Project costs because it is a similar size project

[2]Transmission costs based on Time and Material Contract with Energy Delivery Contractor

[3]Land costs include acquisition and closing of land

[4]Owners costs include actuals and monthly forecast for remaining duration of project

[5] Includes Contractor Engineering and Development costs

Definition Table:
FTNP - Full Notice to Proceed
MV - Mid-Voltage
SUT- Step-Up Transformer

4. **Cost-effectiveness.** Please refer to Page 18, Lines 11-17, of the direct testimony of witness Ward. Provide the calculations used to determine the projected weighted average costs of the First SoBRA, the Second SoBRA, and the First and Second SoBRAs together. If the document is available in Excel format, please provide it as such with all formulas intact.

A. The requested information is provided in the following table. This information is also provided in "POD No 4.xlsx."

Project Cost (Based on AC Output)

Project	In-service Date	MW	All-in-Cost w/ AFUDC ($)	All-in-Cost w/ AFUDC ($/kw)
Balm Solar	9/1/2018	74.4	108,319,895	1,455.75
Payne Creek	9/1/2018	70.3	93,244,592	1,326.61
Tranche 1		**144.7**	**201,564,487**	**1,393.02**
Lithia	1/1/2019	74.5	111,315,962	1,494.17
Grange Hall	1/1/2019	61.1	87,832,373	1,437.52
Peace Creek	1/1/2019	55.4	82,635,490	1,491.62
Bonnie Mine	1/1/2019	37.5	54,905,753	1,464.15
Lake Hancock	1/1/2019	31.8	47,516,527	1,494.23
Tranche 2		**260.3**	**384,206,106**	**1,476.01**
Tranche 1 and 2 Total		**405.0**	**585,770,593**	**1,446.36**

5. Please refer to the Direct Testimony of TECO witness Rocha, page 21, lines 15-25. Please provide copies of the Company's high and low fuel forecasts relied upon in developing its CPVRR analysis discussed in this section of testimony.

A. The requested information is provided in the following tables.

High Fuel Forecast ($/MMBtu)

	Coal	Natural Gas
2018	2.42	3.03
2019	2.47	2.98
2020	2.49	3.28
2021	2.62	3.77
2022	2.72	4.28
2023	2.81	4.69
2024	2.87	4.97
2025	3.01	5.27
2026	3.16	5.62
2027	3.24	5.99
2028	3.35	6.35
2029	3.49	6.83
2030	3.53	7.02
2031	3.74	7.72
2032	3.99	8.57
2033	4.09	9.00
2034	4.29	9.75
2035	4.45	10.36
2036	4.60	10.99
2037	4.76	11.68
2038	4.95	12.49
2039	5.12	13.23
2040	5.29	14.03
2041	5.37	14.50
2042	5.49	14.85
2043	5.64	15.32
2044	5.90	16.22
2045	6.14	17.06

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High Fuel Forecast ($/MMBtu)

	Coal	Natural Gas
2046	6.34	17.73
2047	6.59	18.56
2048	6.95	19.80

Low Fuel Forecast ($/MMBtu)

	Coal	Natural Gas
2018	2.42	3.03
2019	2.37	2.98
2020	2.29	2.83
2021	2.26	2.84
2022	2.24	2.71
2023	2.27	2.64
2024	2.33	2.67
2025	2.40	2.84
2026	2.52	2.96
2027	2.56	3.09
2028	2.65	3.30
2029	2.72	3.48
2030	2.72	3.51
2031	2.84	3.82
2032	2.92	4.05
2033	2.95	4.16
2034	2.96	4.22
2035	3.01	4.40
2036	3.08	4.64
2037	3.14	4.85
2038	3.23	5.14
2039	3.32	5.45
2040	3.38	5.70
2041	3.40	5.81

Low Fuel Forecast ($/MMBtu)

	Coal	Natural Gas
2042	3.45	5.92
2043	3.52	6.04
2044	3.59	6.20
2045	3.65	6.31
2046	3.71	6.45
2047	3.79	6.62
2048	3.88	6.81

6. Please refer to the Direct Testimony of TECO witness Rocha, page 21, lines 15-25. Please provide copies of the Company's base, high, and low environmental compliance cost forecasts relied upon in developing its CPVRR analysis referenced in this section of testimony.

A. The CO_2 price forecast used in the cost-effectiveness analysis for the second tranche of solar was purchased from a global consulting services company, ICF International, Inc., and developed in the third quarter of 2017. The NO_X price forecast is estimated using an actual sale of Tampa Electric's NO_X Ozone Season allowances in 2016, at $170 per ton, and escalated by one percent a year after 2017.

Please see the following table for the CO_2 price forecast.

REDACTED

Calendar Year Values (2016$/Short Ton)

Region: SERC+FL	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
High CO2	[redacted]															
Base CO2	[redacted]															
Low CO2	[redacted]															

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2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
[redacted]																	

7. Please refer to the Direct Testimony of TECO witness Rocha, page 16, lines 21-25. Please provide all (if any) alternative fuel and emissions forecasts TECO used to gauge the robustness of its proposed SoBRA transaction.

A. The fuel and emissions forecasts provided in responses to Production of Documents Request No. 5 and 6 are the fuel and emissions forecasts used to gauge the robustness of the proposed Second SoBRA.

8. Appendix B (Typical Bill Analysis) to the petition indicates a bill increase of $1.28 per month for residential customers who use 1,000 kWh per month. Considering the proposed bill impacts stated above, please discuss how and when TECO will inform its customers about the proposed changes. Also, please provide examples of a customer letter, website information, door hanger, press release etc. that are considered TECO's communication methods to inform customers of bill impacts.

A. The approved changes to rates resulting from this docket are expected to be made in the first billing cycle of January 2019. That same billing cycle will bring changed rates from the fuel and cost recovery clause dockets as well as the tax reform docket (Docket No. 20180045-EI). Tampa Electric plans to inform its customers of these changes one month prior to the effective date of the change. The notice will be included as the last page of the customer's bill and will be very similar to the attached notice for the January 2018 annual clause adjustments.

Important rate information for commercial and industrial customers

Please note this important information about your 2018 electric bill, including changes to fuel charges.

Effective January 2018, your bill will reflect slightly higher fuel prices and other factors approved by the Florida Public Service Commission as part of an annual adjustment. Fuel costs are passed through from fuel suppliers to our customers with no markup or profit to Tampa Electric.

We have several rate schedules for our commercial and industrial customers. Depending on the actual maximum electricity load your facility requires, we will select the appropriate rate schedule. (Your rate schedule appears in the center portion of your bill under "New Charges").

Tampa Electric's Business and Industry department can discuss any questions you have regarding your account and the charges involved. Please contact us at one of the following numbers:

Hillsborough County
(813) 228-1010

Polk County
(863) 299-0800

All other counties and out-of-state
(888) 223-0800

To learn more about our rates and how you can make managing energy costs easier, visit **tampaelectric.com** for energy-savings tips that can help you lower your monthly electric bill.

Effective January 2018

Standard General Service, Demand (GSD)

Basic Service Charge:	$33.24 per month
Demand Charge:	$ 10.25 per kW
Energy Charge:	1.754 ¢ per kWh
Fuel Charge:	3.132 ¢ per kWh
Capacity Charge:	$ 0.20 per kW
Energy Conservation Charge:	$ 0.87 per kW
Environmental Charge:	0.342 ¢ per kWh

Optional General Service, Demand (GSD-option)

Basic Service Charge:	$33.24 per month
Energy Charge:	6.660 ¢ per kWh
Fuel Charge:	3.132 ¢ per kWh
Capacity Charge:	0.047 ¢ per kWh
Energy Conservation Charge:	0.201 ¢ per kWh
Environmental Charge:	0.342 ¢ per kWh

Time-of-Day General Service, Demand (GSDT)

Basic Service Charge:	$33.24 per month	
Demand Charge:	$ 3.46 per kW of billing demand $ 6.79 per kW of peak billing demand	
	On-Peak	Off-Peak
Energy Charge:	3.211 (¢ per kWh)	1.159 (¢ per kWh)
Fuel Charge:	3.330 (¢ per kWh)	3.047 (¢ per kWh)
Capacity Charge	$ 0.20 per kW	
Energy Conservation Charge:	$ 0.87 per kW	
Environmental Charge	0.342 ¢ per kWh	

Interruptible Service (IS) - Closed to new customers

Basic Service Charge:	$689.11 per month
Demand Charge:	$ 1.61 per kW
Energy Charge:	2.774 ¢ per kWh
Fuel Charge:	3.101 ¢ per kWh
Capacity Charge:	$ 0.14 per kW
Energy Conservation Charge:	$ 0.67 per kW
Environmental Charge:	0.333 ¢ per kWh

Interruptible Service Time-of-Day (IST) - Closed to new customers

Basic Service Charge:	$689.11 per month	
Demand Charge:	$ 1.61 per kW of billing demand	
	On-Peak	Off-Peak
Energy Charge:	2.774 (¢ per kWh)	2.774 (¢ per kWh)
Fuel Charge:	3.297 (¢ per kWh)	3.017 (¢ per kWh)
Capacity Charge:	$ 0.14 per kW	
Energy Conservation Charge:	$ 0.67 per kW	
Environmental Charge:	0.333¢ per kWh	

The fuel charge is used to pay the fuel suppliers and does not profit Tampa Electric.

Rate schedules are subject to gross receipts taxes, city and state taxes, and franchise fees, where applicable. A late payment charge may be applied to any unpaid balance on your electric bill that is not paid by the past-due date.

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Important Rate Information for Residential and Non-Demand Customers

Please note this important information about your 2018 electric bill, including changes to fuel charges.

Effective January 2018, your bill will reflect slightly higher fuel prices and other factors approved by the Florida Public Service Commission as part of an annual adjustment. Fuel costs are passed through from fuel suppliers to our customers with no markup or profit to Tampa Electric.

Effective January 2018		
Standard Residential Rate (RS)		
Basic Service Charge:	$16.62 per month	
Energy Charge:		
Usage up to 1,000 kWh	5.855 ¢ per kWh	
Usage over 1,000 kWh	6.963 ¢ per kWh	
Fuel Charge:		
Usage up to 1,000 kWh	2.818 ¢ per kWh	
Usage over 1,000 kWh	3.818 ¢ per kWh	
Residential Service Variable Pricing (RSVP-1)		
Basic Service Charge:	$16.62 per month	
Energy Charge:	4.900 ¢ per kWh	
Fuel Charge:	3.132 ¢ per kWh	
Standard General Service, Non-Demand (GS)		
Basic Service Charge:	$19.94 per month	
Energy Charge:	6.184 ¢ per kWh	
Fuel Charge:	3.132 ¢ per kWh	
Time-of-Day General Service, Non-Demand (GST)		
Basic Service Charge:	$22.16 per month	
	On-Peak (¢ per kWh)	Off-Peak (¢ per kWh)
Energy Charge:	15.823	1.665
Fuel Charge:	3.330	3.047

The rate schedules above are subject to gross receipts taxes, city and state taxes, and franchise fees, where applicable. A late payment charge may be applied to any unpaid balance on your electric bill that is not paid by the past-due date.

The energy charge includes 0.655 cents per kWh for rate schedule RS, (0.649) cents per kWh for rate schedule RSVP-1 (based on P2 pricing – rate can vary based on rate tier), 0.635 cents per kWh for rate schedules GS and GST for the conservation, environmental and capacity cost recovery charges.

About your bill

Basic Service Charge

The monthly basic service charge covers the cost of maintaining your electric meter and the wires that bring electrical service to your home or business. The basic service charge also covers the cost of reading the meter and maintaining customer records and accounting for bill payments, credit and other transactions affecting your account. Basic service charges are incurred even if no electricity is used during the month.

Energy Charge

The energy charge includes all other costs of producing the electricity you purchase, except fuel. This also includes conservation, environmental and capacity cost recovery charges. Effective January 2018, residential customers will be billed 5.855 cents per kilowatt-hour (kWh) for the first 1,000 kWh of energy usage and 6.963 cents per kWh for any usage over 1,000 kWh under Tampa Electric's tiered rate structure.

Fuel Charge

This is the cost of fuel used to produce your electricity. Fuel costs are passed through from fuel suppliers to our customers with no markup or profit to Tampa Electric. Effective January 2018, residential customers will be billed 2.818 cents per kWh for fuel usage up to 1,000 kWh, and 3.818 cents per kWh for any usage over 1,000 kWh.

To learn more about our rates and how you can make managing energy costs easier, visit **tampaelectric.com** for energy-savings tips that can help you lower your monthly electric bill. If you prefer to speak with a representative, please call:

Hillsborough County
(813) 223-0800

Polk County
(863) 299-0800

All other counties and out-of-state
1-888-223-0800

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TEC 102317

9. TECO requests that the proposed tariff changes if approved be effective with the first billing cycle of January 2019. Please indicate when the first billing cycle of January will begin.

A. The first billing cycle of January 2019 will be January 3, 2019.

10. Twenty-fourth revised tariff sheet 6.030 indicates that the energy and demand charge for the first 1,000 kWh for residential service will increase from 4.896 cents per kWh to 5.143 cents per kWh. Please discuss the reason for this increase.

A. Please see the direct testimony of William R. Ashburn, Exhibit No. WRA-1, Document No. 2, Page 2 of 17. This increase occurs to recover the appropriately allocated Second SoBRA revenue requirement from residential service customers.

11. Page 9 of witness Ashburn's direct testimony states that certain rates in each rate class were increased to recover the identified revenue requirement. Please expand on this statement.

A. As described in that testimony, and as directed as part of the 2017 Settlement Agreement, certain rates in each rate class are to be increased to recover the SoBRA revenue requirement. At page 7 of witness Ashburn's direct testimony, an explanation is provided as to how certain rates are to be impacted, and were impacted, within the SoBRA rate design.

7

Staff's Second Data Request Nos. 27 – 38

(See additional files contained on Staff Hearing Exhibit CD/USB for 28.)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180133-EI EXHIBIT: 7
PARTY: STAFF – (DIRECT)
DESCRIPTION: James Rocha

[5] Document No. 04813-2018, filed on July 23, 2018, in Docket No. 20180133-EI.

27. Referring to TECO's witness Rocha Direct Testimony, page 9, lines 17 – 21, please explain why the depreciation expense used in the calculation of Second SoBRA Revenue Requirements is deemed a "reasonable" estimate.

A. The detailed costs of the Second SoBRA projects are described in Mr. Ward's testimony. The cost is subject to a cap and a subsequent true-up. Tampa Electric determined that the appropriate economic life of a photovoltaic solar facility is thirty years. In addition, Tampa Electric is aware that other solar projects regulated by the FPSC have used a thirty-year book life. Future SoBRA true-up filings will capture any differences from estimated costs.

28. Please refer to witness Rocha's Direct Testimony, Exhibit RJR-1, Document 3, for the following questions:

a. Referring to page 1 of Document 3, please specify, respectively, the depreciation expense amounts included in the Revenue Requirement for each of the five projects, as well as in total, of TECO's Second SoBRA.

b. Referring to page 1 of Document 3, please identify the following that were used in deriving the depreciation expense amount discussed in Question (a): i) average service life, ii) plant-in-service amount each month and; iii) depreciation rate(s) used with specification of Commission order(s) by which the rate(s) was/were approved.

c. Referring to page 1 of Document 3, please explain in detail how each depreciation expense amount discussed in Question (a) was derived.

d. Please provide working papers in Microsoft Excel, with formulas intact, to support TECO's response to Interrogatory No. 2.(c).

e. Please explain how the schedule presented on page 2 of Document 3 was derived from the schedule presented on page 1 of Document 3.

A. a. Book depreciation for Lithia Solar is $3.3 million, Grange Hall Solar is $2.6 million, Peace Creek Solar is $2.4 million, Bonnie Mine Solar is $1.7 million, and Lake Hancock Solar is $1.4 million for a total of $11.343 million in annual book depreciation for the Second SoBRA shown on Exhibit No. RJR-1, page 1 of Document No. 3.

b. The company uses a thirty-year book life, with straight line depreciation for tracking photovoltaic solar facilities. The in-service date of January 1, 2019 used in Document 3, page 1, includes 260.3 MW_{AC} of solar in-service on the same date.

c. In the Excel file referred to in the company's response to Data Request No. 28(d), these project costs include AFUDC and are shown in cells E3 through E25. The useful life of the solar asset is listed as the book life shown on row 31 as thirty years. Annual book depreciation is 1/30th of the capital and AFUDC cost of the depreciable assets. By adding the book depreciation for Lithia Solar, Grange Hall Solar, Peace Creek Solar, Bonnie Mine Solar and Lake Hancock Solar, the Second SoBRA book depreciation is $11.343 million.

d. The Excel file titled "20180133 Staff's 2nd Data Request.xlsx" tab "Q28" provides the calculation of the revenue requirement for the Second SoBRA without the incentive.

e. The difference between Exhibit No. RJR-1, Document No. 3, Page 1 and Page 2, is the incentive, or sharing mechanism.

29. Referring to witness Rocha Direct Testimony, page 15, lines 23 – 24, for the following questions:

a. Please explain in detail how the referenced "book depreciation" was calculated, and specify the associated depreciation rate, average service life, and the plant-in-service amounts used in calculation.

b. Please provide working papers in Microsoft Excel, with formulas intact, to support TECO's response to Interrogatory No. 3.(a).

c. Please identify the amount of annual "book depreciation" witness Rocha derived.

A. a. The associated depreciation rate and average service life is as described in the response to Staff's Second Data Request, No. 27. Tampa Electric provided an Excel file labeled "20180133 Staff's 1st Data Request W Formulas Provided 08032018.xlsx" on August 3, 2018, as part of the response to Staff's First Data Request, No. 1. Tab "Q1" of that file provides the plant in-service amounts, with incentive, at cells E3 through E25.

b. Tampa Electric provided an Excel file labeled "20180133 Staff's 2nd Data Request.xlsx" as part of the response to Staff's Second Data Request, No. 28. Tab "Q28" of that file provides the plant in-service amounts, without incentive. Also see the response to Staff's Second Data Request, No. 29, subpart (a).

c. With incentive, the annual book depreciation is $11.396 million.

30. Please refer to witness Rocha Direct Testimony, page 16, lines 4 – 10, and page 20, lines 16 – 19, for the following questions:

a. Does TECO plan to recover its solar generation costs in excess of the Second SoBRA? (The excess costs are the expense amounts associated with constructing 278 MW – 260.3 MW = 17.7 MW solar generation)

b. If TECO's response to Question 4 (a) is positive, please discuss when and how TECO is planning to do so and how such plan comports with the 2017 Agreement.

c. With respect to the recovery of solar generation capital investment through depreciation, please explain how TECO will book the plant assets associated with the 260.3 MW (recoverable for the Second SoBRA) and 17.7 MW (non-recoverable for the Second SoBRA) solar facilities separately onto a same set of affected depreciation accounts.

A. a. In accordance with Tampa Electric's 2017 Settlement agreement, the company will not recover these revenue requirements in the Second SoBRA but will include the costs of the 17.7 MW of solar generation in surveillance reporting.

b. At the time that the company submits its petition for its third tranche of solar projects it would include the depreciated net book value of the 17.7 MW. Since the MW amounts of solar generation to be included in the company's SoBRA are limited in accordance with Paragraph 6(b) of the 2017 Agreement, the company would pass the fuel benefits to customers and defer the recovery of costs until allowed to do so in accordance with Paragraph 6(b) of the 2017 Agreement. Information has already been provided to demonstrate the 17.7 MW are cost-effective and below the $1,500 per kWac cost cap requirement in the agreement.

c. When the asset goes into service, the total amount will be included in the depreciable base for the various solar accounts. Tampa Electric will be able to separately identify the depreciation for the additional 17.7 MW of solar generation when the Third SoBRA filing is submitted.

For all questions and requests please refer to the direct testimony of witness Rocha, exhibit RJR-1, Document 1 of the instant docket, the direct testimony of witness Rocha, exhibit RJR-1, in TECO's previous petition for SoBRA (docket No. 20180260-EI), and TECO's 2018 Ten Year Site Plan (TYSP):

31. The energy forecast in Exhibit RJR-1, Document 1 of the instant docket shows a projected decrease from 2018 (20,588 GWh) to 2019 (20,445 GWh). No other decreases appear from 2020 through 2048. What are the reasons for this decrease?

A. The company updated its demand and energy forecast after the TYSP filing. The updated energy forecast shown on Exhibit No. RJR-1, Document No. 1, of witness Rocha's testimony includes actual data from the first quarter of 2018. In the first quarter of 2018, Tampa Electric experienced favorable weather in January and February, resulting in an overall higher energy forecast for 2018 when compared to 2019. Otherwise, the Tampa Electric forecast is based on a normal weather pattern.

32. Does the energy forecast in Exhibit RJR-1, Document 1 of the instant docket represent TECO's most current forecast?

A. Yes. The energy forecast in Exhibit No. RJR-1, Document No. 1 represents Tampa Electric's most current energy forecast.

33. Why does TECO's energy forecast, as shown in Exhibit RJR-1, Document 1 exceed the forecast in the its 2018 TYSP, Schedule 2.2, Column (8), for each year through 2027?

A. As explained in the company's response to Staff's Second Data Request, No. 31, the company updated its demand and energy forecast after the TYSP filing. In addition, the forecast shown in Exhibit No. RJR-1, Document No. 1 is higher than the TYSP, Schedule 2.2, Column (8), because it includes losses and company use.

34. The peak summer and winter demand forecasts shown in Exhibit RJR-1, Document 1 differ from the forecasts of summer and winter peak demand shown in Schedules 3.1 and 3.2, total peak demand, column (2) and Net Firm Demand, column (10), of TECO's 2018 TYSP. What are the reasons for these differences?

A. As explained in the company's response to Staff's Second Data Request, No. 31, the company updated its demand and energy forecast after the TYSP filing.

35. Please clarify whether the 2018 winter demand forecast in Exhibit RJR-1, Document 1, of 4,044 MW corresponds to the 2017/18 or 2018/19 forecast in Schedule 3.2 of the 2018 TYSP. If the answer is 2017/2018, does the entry represent the actual winter demand for 2018?

A. The 2018 winter demand forecast in Exhibit No. RJR-1, Document No. 1, of 4,044 MW corresponds to the winter period December 2017 through March 2018. The 2018 entry is the actual peak demand from January of 2018.

36. On what date did the energy forecast in Exhibit RJR-1, Document 1 become TECO's official forecast?

A. The energy forecast shown in Exhibit No. RJR-1, Document No. 1 was approved in June of 2018. It is standard practice for Tampa Electric to update its inputs prior to the fuel filing every year.

37. What is the date of the next expected revision to TECO's energy forecast?

A. The energy forecast is updated annually and is typically completed in June of each year.

38. Please reconcile the energy forecast in Exhibit RJR-1 with the billing determinants in the rates schedules contained in witness Ashburn's exhibit WRA-1, Document 2, Schedule E-13c, including all relevant worksheets.

A. Exhibit No. RJR-1, Document No. 1, page 1 of 1, shows demand or energy values. The demand values shown are coincident peak demands in MW for the summer and winter periods. The billing determinants used in witness Ashburn's Exhibit No. WRA-1, Document No. 2, Schedule E-13c, are not coincident peak demands, but rather billing demands. The energy values shown in witness Rocha's exhibit are total system energy at the generator level. The energy billing determinants used in witness Ashburn's exhibit are billed energy at the meter.

8

Staff's 1st Interrogatories Nos. 1 – 5

Confidential DN. 05478-2018

(Nos. 1 and 5)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180133-EI   EXHIBIT: 8
PARTY: STAFF – (DIRECT)
DESCRIPTION: James Rocha

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Petition for limited proceeding to approve second solar base rate adjustment (SoBRA), effective January 1, 2019 by Tampa Electric Company	**DOCKET NO. 20180133-EI** **FILED: August 23, 2018**

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST SET OF INTERROGATORIES (NOS. 1-5)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 1-5) propounded and served on August 9, 2018, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
INDEX TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-5)

Number	Witness	Subject	Bates Stamped Page
1	Rocha	Please refer to TECO's supplemental response to Staff's First Data Request (filed August 6, 2018), No. 23. a. Are TECO's fuel price sensitivities (values) for the "near and mid-term" time periods obtained solely from PIRA? As in, did PIRA completely formulate the near and mid-term fuel price sensitivity levels discussed in the aforecited response? b. If the response to (a.) is negative, how and by what methodology does TECO adjust the values/information purchased from PIRA related to forecasted fuel price sensitivity levels? Please fully explain how such adjustments to the data obtained from PIRA are formulated. c. Are TECO's fuel price sensitivities values for the "long-term time period" sourced solely from the Energy Information Administration (EIA)? As in, did the EIA wholly formulate in the long-term fuel price sensitivity levels discussed to in the aforecited response? d. If the response to (c.) is negative, how and by what methodology does TECO adjust the values/information sourced from the EIA related to forecasted fuel price sensitivity levels? Please fully explain how such adjustments to the data sourced from the EIA are formulated.	1
2	Rocha	In its response to Staff's First Data Request, No. 27(a), TECO indicates "Actual natural gas prices often vary from forecasted prices by more than 20 percent. This occurs despite the forecasted prices being based on independent, industry-recognized sources". What probabilities, if any, did TECO assign to its base, high, and low natural gas price forecasts in this proceeding, and what method did the Company use to derive such probabilities?	11

3	Rocha	Please refer to witness Rocha's direct testimony exhibit, Document No. 2 and TECO's response to Staff's First Production of Documents, No. 5. What probabilities, if any, did TECO assign to its base, high, and low coal price forecasts in this proceeding, and what method did the Company use to derive such probabilities?	12
4	Rocha	If TECO did not assign probabilities to it base, high, and low natural gas and coal price forecasts provided in this proceeding, please explain why it chose not to do so.	13
5	Rocha	Please refer to the Direct Testimony of TECO witness Rocha, Exhibit RJR-1, Document No. 2, Page 1 of 1. Do the forecasted prices shown on this exhibit include transportation/delivery costs? If not, please provide an updated fuel price forecast listing separate commodity and transportation/delivery charges.	14

Jim Rocha
Director, Planning Strategy and Compliance

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

1. Please refer to TECO's supplemental response to Staff's First Data Request (filed August 6, 2018), No. 23.

   a. Are TECO's fuel price sensitivities (values) for the "near and mid-term" time periods obtained solely from PIRA? As in, did PIRA completely formulate the near and mid-term fuel price sensitivity levels discussed in the aforecited response?

   b. If the response to (a.) is negative, how and by what methodology does TECO adjust the values/information purchased from PIRA related to forecasted fuel price sensitivity levels? Please fully explain how such adjustments to the data obtained from PIRA are formulated.

   c. Are TECO's fuel price sensitivities values for the "long-term time period" sourced solely from the Energy Information Administration (EIA)? As in, did the EIA wholly formulate in the long-term fuel price sensitivity levels discussed to in the aforecited response?

   d. If the response to (c.) is negative, how and by what methodology does TECO adjust the values/information sourced from the EIA related to forecasted fuel price sensitivity levels? Please fully explain how such adjustments to the data sourced from the EIA are formulated.

A. a. No, the near-term and mid-term forecasts are not obtained solely from PIRA. The near-term prices are from NYMEX for natural gas and from the *Coal Daily* published index forward prices for coal. Prices transition from the near-term source to the mid-term source by progressive blending of the two sources over several years. This process allows a smooth transition from one source to the other. The tables provided in the response to subpart (d) show the weighting percentages as the forecasts are aligned.

b. The mid-term data source for both natural gas and coal is PIRA's Scenario Planning Service issued in February 2018.

The natural gas forecast adjustments are listed below.

1. Calculate the nominal price of natural gas by applying the projected Consumer Price Index Less Energy inflation adjustment factors to PIRA's "real" (also known as "constant dollar") forecasted price of natural gas;

2. A basis adjustment is applied to account for the location of Tampa Electric's pipeline receipt points, which are mostly near Mobile, Alabama (called FGT Zone 3), instead of at Henry Hub, which is the receipt point for the PIRA, NYMEX and EIA price forecasts.

The coal adjustments are listed below.

1. Recent price ratios are used to derive a forecast price for Illinois Basin coal from the Central Appalachian and/or foreign low sulfur coal price forecasts provided by PIRA.
2. The nominal price of coal is calculated by adjusting PIRA's real price forecast by the projected Consumer Price Index Less Energy inflation adjustment factor.
3. The price forecast is adjusted the price to reflect the specific quality characteristics of Illinois Basin coal needed for Tampa Electric's units.

c. No. For natural gas the long-term time period price forecasts contain a transition period where the weighting of the PIRA price forecast percent change diminishes and the weighting of the EIA price forecast percent change increases each year until the EIA forecast changes represent 100% of the forecast used for the years after PIRA's forecast ends.

For coal, the mid-term period forecast is based on the PIRA forecast changes, and then the annual escalation from the natural gas forecast during the transition period and the 100% EIA period is applied to the coal price forecast to extend it past the mid-term period after the PIRA forecast ends.

These processes allow a smooth transition from one forecast source to another. Also see the tables provided in the response to subpart (d).

d. See the response to subpart (c) and the following tables and charts.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
STAFF'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 1

FILED: AUGUST 23, 2018

Tampa Electric Derivation of Natural Gas Commodity Price Forecast - High
$/MMBtu

				Weighting Factors			TEC Forecast		
	NYMEX	PIRA	EIA	NYMEX	PIRA	EIA	TEC NG @ HH	HH to FGT Z3 Basis	@FGT Z3 Receipt
2018	2.84	[redacted]	3.29	100%	0%	0%	[redacted]	[redacted]	[redacted]
2019	2.79	[redacted]	4.41	100%	0%	0%	[redacted]	[redacted]	[redacted]
2020	2.77	[redacted]	5.52	75%	25%	0%	[redacted]	[redacted]	[redacted]
2021	2.81	[redacted]	5.93	50%	50%	0%	[redacted]	[redacted]	[redacted]
2022	2.86	[redacted]	6.36	25%	75%	0%	[redacted]	[redacted]	[redacted]
2023	2.92	[redacted]	6.90	0%	100%	0%	[redacted]	[redacted]	[redacted]
2024	2.97	[redacted]	7.45	0%	100%	0%	[redacted]	[redacted]	[redacted]
2025	3.03	[redacted]	7.96	0%	100%	0%	[redacted]	[redacted]	[redacted]
2026	3.08	[redacted]	8.33	0%	100%	0%	[redacted]	[redacted]	[redacted]
2027	3.14	[redacted]	8.68	0%	100%	0%	[redacted]	[redacted]	[redacted]
2028		[redacted]	9.01	0%	100%	0%	[redacted]	[redacted]	[redacted]
2029		[redacted]	9.39	0%	100%	0%	[redacted]	[redacted]	[redacted]
2030		[redacted]	9.55	0%	100%	0%	[redacted]	[redacted]	[redacted]
2031		[redacted]	9.77	0%	90%	10%	[redacted]	[redacted]	[redacted]
2032		[redacted]	10.05	0%	80%	20%	[redacted]	[redacted]	[redacted]
2033		[redacted]	10.30	0%	70%	30%	[redacted]	[redacted]	[redacted]
2034		[redacted]	10.70	0%	60%	40%	[redacted]	[redacted]	[redacted]
2035		[redacted]	11.07	0%	50%	50%	[redacted]	[redacted]	[redacted]
2036		[redacted]	11.59	0%	40%	60%	[redacted]	[redacted]	[redacted]
2037		[redacted]	11.96	0%	30%	70%	[redacted]	[redacted]	[redacted]
2038		[redacted]	12.40	0%	20%	80%	[redacted]	[redacted]	[redacted]
2039		[redacted]	12.77	0%	10%	90%	[redacted]	[redacted]	[redacted]
2040		[redacted]	13.17	0%	0%	100%	[redacted]	[redacted]	[redacted]
2041		[redacted]	13.62	0%	0%	100%	[redacted]	[redacted]	[redacted]
2042		[redacted]	13.94	0%	0%	100%	[redacted]	[redacted]	[redacted]
2043		[redacted]	14.38	0%	0%	100%	[redacted]	[redacted]	[redacted]
2044		[redacted]	15.24	0%	0%	100%	[redacted]	[redacted]	[redacted]
2045		[redacted]	16.03	0%	0%	100%	[redacted]	[redacted]	[redacted]
2046		[redacted]	16.66	0%	0%	100%	[redacted]	[redacted]	[redacted]
2047		[redacted]	17.45	0%	0%	100%	[redacted]	[redacted]	[redacted]
2048		[redacted]	18.63	0%	0%	100%	[redacted]	[redacted]	[redacted]

Note: 2018 values for NYMEX, PIRA and EIA reflect actual NYMEX closed prices for the first six months of the year and forecasted prices for the last six months of the year.

REDACTED

[redacted]

REDACTED

Tampa Electric Derivation of Natural Gas Commodity Price Forecast - Low
$/MMBtu

				Weighting Factors			TEC Forecast		
	NYMEX	PIRA	EIA	NYMEX	PIRA	EIA	TEC NG @ HH	HH to FGT Z3 Basis	@FGT Z3 Receipt
2018	2.84	[redacted]	2.91	100%	0%	0%	[redacted]	[redacted]	[redacted]
2019	2.79	[redacted]	3.24	100%	0%	0%	[redacted]	[redacted]	[redacted]
2020	2.77	[redacted]	3.60	75%	25%	0%	[redacted]	[redacted]	[redacted]
2021	2.81	[redacted]	3.42	50%	50%	0%	[redacted]	[redacted]	[redacted]
2022	2.86	[redacted]	3.32	25%	75%	0%	[redacted]	[redacted]	[redacted]
2023	2.92	[redacted]	3.38	0%	100%	0%	[redacted]	[redacted]	[redacted]
2024	2.97	[redacted]	3.50	0%	100%	0%	[redacted]	[redacted]	[redacted]
2025	3.03	[redacted]	3.65	0%	100%	0%	[redacted]	[redacted]	[redacted]
2026	3.08	[redacted]	3.84	0%	100%	0%	[redacted]	[redacted]	[redacted]
2027	3.14	[redacted]	4.02	0%	100%	0%	[redacted]	[redacted]	[redacted]
2028		[redacted]	4.16	0%	100%	0%	[redacted]	[redacted]	[redacted]
2029		[redacted]	4.26	0%	100%	0%	[redacted]	[redacted]	[redacted]
2030		[redacted]	4.32	0%	100%	0%	[redacted]	[redacted]	[redacted]
2031		[redacted]	4.40	0%	90%	10%	[redacted]	[redacted]	[redacted]
2032		[redacted]	4.47	0%	80%	20%	[redacted]	[redacted]	[redacted]
2033		[redacted]	4.50	0%	70%	30%	[redacted]	[redacted]	[redacted]
2034		[redacted]	4.54	0%	60%	40%	[redacted]	[redacted]	[redacted]
2035		[redacted]	4.61	0%	50%	50%	[redacted]	[redacted]	[redacted]
2036		[redacted]	4.72	0%	40%	60%	[redacted]	[redacted]	[redacted]
2037		[redacted]	4.78	0%	30%	70%	[redacted]	[redacted]	[redacted]
2038		[redacted]	4.91	0%	20%	80%	[redacted]	[redacted]	[redacted]
2039		[redacted]	5.07	0%	10%	90%	[redacted]	[redacted]	[redacted]
2040		[redacted]	5.19	0%	0%	100%	[redacted]	[redacted]	[redacted]
2041		[redacted]	5.27	0%	0%	100%	[redacted]	[redacted]	[redacted]
2042		[redacted]	5.37	0%	0%	100%	[redacted]	[redacted]	[redacted]
2043		[redacted]	5.48	0%	0%	100%	[redacted]	[redacted]	[redacted]
2044		[redacted]	5.62	0%	0%	100%	[redacted]	[redacted]	[redacted]
2045		[redacted]	5.72	0%	0%	100%	[redacted]	[redacted]	[redacted]
2046		[redacted]	5.84	0%	0%	100%	[redacted]	[redacted]	[redacted]
2047		[redacted]	5.99	0%	0%	100%	[redacted]	[redacted]	[redacted]
2048		[redacted]	6.17	0%	0%	100%	[redacted]	[redacted]	[redacted]

Note: 2018 values for NYMEX, PIRA and EIA reflect actual NYMEX closed prices for the first six months of the year and forecasted prices for the last six months of the year.

REDACTED

[redacted]

REDACTED

Tampa Electric Derivation of STD Coal Commodity Price Forecast - High
$/MMBtu

	Published Index	PIRA	EIA NG Esc %	Weighting Factors: Index	Weighting Factors: PIRA	Weighting Factors: EIA NG Esc %	TEC Forecast STD Coal
2018	1.67	[redacted]	[redacted]	100%	0%	0%	[redacted]
2019	1.61	[redacted]	[redacted]	75%	25%	0%	[redacted]
2020	1.63	[redacted]	[redacted]	50%	50%	0%	[redacted]
2021	1.73	[redacted]	[redacted]	25%	75%	0%	[redacted]
2022		[redacted]	[redacted]	0%	100%	0%	[redacted]
2023		[redacted]	[redacted]	0%	100%	0%	[redacted]
2024		[redacted]	[redacted]	0%	100%	0%	[redacted]
2025		[redacted]	[redacted]	0%	100%	0%	[redacted]
2026		[redacted]	[redacted]	0%	100%	0%	[redacted]
2027		[redacted]	[redacted]	0%	100%	0%	[redacted]
2028		[redacted]	[redacted]	0%	100%	0%	[redacted]
2029		[redacted]	[redacted]	0%	100%	0%	[redacted]
2030		[redacted]	[redacted]	0%	100%	0%	[redacted]
2031		[redacted]	[redacted]	0%	0%	100%	[redacted]
2032		[redacted]	[redacted]	0%	0%	100%	[redacted]
2033		[redacted]	[redacted]	0%	0%	100%	[redacted]
2034		[redacted]	[redacted]	0%	0%	100%	[redacted]
2035		[redacted]	[redacted]	0%	0%	100%	[redacted]
2036		[redacted]	[redacted]	0%	0%	100%	[redacted]
2037		[redacted]	[redacted]	0%	0%	100%	[redacted]
2038		[redacted]	[redacted]	0%	0%	100%	[redacted]
2039		[redacted]	[redacted]	0%	0%	100%	[redacted]
2040		[redacted]	[redacted]	0%	0%	100%	[redacted]
2041		[redacted]	[redacted]	0%	0%	100%	[redacted]
2042		[redacted]	[redacted]	0%	0%	100%	[redacted]
2043		[redacted]	[redacted]	0%	0%	100%	[redacted]
2044		[redacted]	[redacted]	0%	0%	100%	[redacted]
2045		[redacted]	[redacted]	0%	0%	100%	[redacted]
2046		[redacted]	[redacted]	0%	0%	100%	[redacted]
2047		[redacted]	[redacted]	0%	0%	100%	[redacted]
2048		[redacted]	[redacted]	0%	0%	100%	[redacted]

REDACTED

[redacted]

REDACTED

Tampa Electric Derivation of STD Coal Commodity Price Forecast - Low
$/MMBtu

				Weighting Factors			TEC
	Published Index	PIRA	EIA NG Esc %	Index	PIRA	EIA NG Esc %	Forecast STD Coal
2018	1.67	[redacted]	[redacted]	100%	0%	0%	[redacted]
2019	1.61	[redacted]	[redacted]	75%	25%	0%	[redacted]
2020	1.63	[redacted]	[redacted]	50%	50%	0%	[redacted]
2021	1.73	[redacted]	[redacted]	25%	75%	0%	[redacted]
2022		[redacted]	[redacted]	0%	100%	0%	[redacted]
2023		[redacted]	[redacted]	0%	100%	0%	[redacted]
2024		[redacted]	[redacted]	0%	100%	0%	[redacted]
2025		[redacted]	[redacted]	0%	100%	0%	[redacted]
2026		[redacted]	[redacted]	0%	100%	0%	[redacted]
2027		[redacted]	[redacted]	0%	100%	0%	[redacted]
2028		[redacted]	[redacted]	0%	100%	0%	[redacted]
2029		[redacted]	[redacted]	0%	100%	0%	[redacted]
2030		[redacted]	[redacted]	0%	100%	0%	[redacted]
2031		[redacted]	[redacted]	0%	0%	100%	[redacted]
2032		[redacted]	[redacted]	0%	0%	100%	[redacted]
2033		[redacted]	[redacted]	0%	0%	100%	[redacted]
2034		[redacted]	[redacted]	0%	0%	100%	[redacted]
2035		[redacted]	[redacted]	0%	0%	100%	[redacted]
2036		[redacted]	[redacted]	0%	0%	100%	[redacted]
2037		[redacted]	[redacted]	0%	0%	100%	[redacted]
2038		[redacted]	[redacted]	0%	0%	100%	[redacted]
2039		[redacted]	[redacted]	0%	0%	100%	[redacted]
2040		[redacted]	[redacted]	0%	0%	100%	[redacted]
2041		[redacted]	[redacted]	0%	0%	100%	[redacted]
2042		[redacted]	[redacted]	0%	0%	100%	[redacted]
2043		[redacted]	[redacted]	0%	0%	100%	[redacted]
2044		[redacted]	[redacted]	0%	0%	100%	[redacted]
2045		[redacted]	[redacted]	0%	0%	100%	[redacted]
2046		[redacted]	[redacted]	0%	0%	100%	[redacted]
2047		[redacted]	[redacted]	0%	0%	100%	[redacted]
2048		[redacted]	[redacted]	0%	0%	100%	[redacted]

REDACTED

[redacted]

2. In its response to Staff's First Data Request, No. 27(a), TECO indicates "Actual natural gas prices often vary from forecasted prices by more than 20 percent. This occurs despite the forecasted prices being based on independent, industry-recognized sources". What probabilities, if any, did TECO assign to its base, high, and low natural gas price forecasts in this proceeding, and what method did the Company use to derive such probabilities?

A. For its natural gas price at Henry Hub forecasts, PIRA assigns 20% probability to its low price forecast, 50% to its base (reference) price forecast, and 30% to its high price forecast. However in this proceeding, Tampa Electric did not assign probabilities to the results of the sensitivities, but rather evaluated the results of the sensitivities individually. The company presented results separately for base, high and low price forecasts.

3. Please refer to witness Rocha's direct testimony exhibit, Document No. 2 and TECO's response to Staff's First Production of Documents, No. 5. What probabilities, if any, did TECO assign to its base, high, and low coal price forecasts in this proceeding, and what method did the Company use to derive such probabilities?

A. For its coal price forecasts, PIRA assigns 30% probability to its low price forecast, 50% to its base (reference) price forecast, and 20% to its high price forecast. However in this proceeding, Tampa Electric did not assign probabilities to the results of the sensitivities, but rather evaluated the results of the sensitivities individually. The company presented results separately for base, high and low price forecasts.

4. If TECO did not assign probabilities to it base, high, and low natural gas and coal price forecasts provided in this proceeding, please explain why it chose not to do so.

A. Tampa Electric analyzed the full projected impact of each of these sensitivities. For example, natural gas prices are at historical lows so while low price forecasts can only go to zero, high price forecasts do not have such a limit.

5. Please refer to the Direct Testimony of TECO witness Rocha, Exhibit RJR-1, Document No. 2, Page 1 of 1. Do the forecasted prices shown on this exhibit include transportation/delivery costs? If not, please provide an updated fuel price forecast listing separate commodity and transportation/delivery charges.

A. The forecasted prices shown on witness Rocha's Exhibit No. RJR-1, Document 2, Page 1 of 1, include variable delivery costs. They do not include the fixed component of gas transportation. See the following tables for base natural gas fuel price forecasts showing the components of commodity and transportation. For example on the natural gas table, the column labeled variable delivered cost matches the information shown in Exhibit RJR-1, Document No. 2, Page 1 of 1, and the following column presents the additional fixed cost of one of the company's firm gas pipeline contracts.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
STAFF'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 5

FILED: AUGUST 23, 2018

Tampa Electric Components of Natural Gas Delivered Price Forecast - Base
$/MMBtu

	Commodity						
	TEC NG Fcst @ HH	HH to FGT Z3 Basis	@FGT Z3 Receipt Point	FGT Fuel and Usage	Variable Delivered Cost	FGT FTS-2 Res. @ 100% Util.	All-in Delivered Cost
2018	[redacted]						3.68
2019							3.64
2020							3.70
2021							3.93
2022							4.10
2023							4.18
2024							4.36
2025							4.62
2026							4.92
2027							5.19
2028							5.47
2029							5.72
2030							5.99
2031							6.30
2032							6.59
2033							6.86
2034							7.10
2035							7.33
2036							7.65
2037							7.93
2038							8.29
2039							8.65
2040							9.00
2041							9.24
2042							9.54
2043							9.81
2044							10.12
2045							10.42
2046							10.72
2047							11.05
2048							11.55

REDACTED

Tampa Electric Components of STD Coal Delivered Price Forecast - Base $/MMBtu					
	Commodity TEC STD Coal	Variable Rail Rate	Variable Delivered Cost	Fixed Rail Rate	All-in Delivered Cost
2018	[redacted]				2.87
2019					2.88
2020					2.85
2021					2.90
2022					2.95
2023					3.03
2024					3.08
2025					3.20
2026					3.35
2027					3.44
2028					3.54
2029					3.63
2030					3.72
2031					3.84
2032					3.93
2033					4.01
2034					4.09
2035					4.15
2036					4.24
2037					4.31
2038					4.40
2039					4.49
2040					4.58
2041					4.62
2042					4.74
2043					4.85
2044					4.97
2045					5.08
2046					5.15
2047					5.27
2048					5.45

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is a Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's First Set of Interrogatories, (Nos. 1-5) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 23rd day of August, 2018.

Penelope A Rusk

Sworn to and subscribed before me this 23rd day of August, 2018.

Cynthia R. Kyle

Notary Public State of Florida
Cynthia R Kyle
My Commission FF 197516
Expires 03/01/2019

My Commission expires ____________________

9

Staff's 1st POD, No. 1

Confidential DN. 05481-2018 (No. 1)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180133-EI EXHIBIT: 9
PARTY: STAFF – (DIRECT)
DESCRIPTION: James Rocha

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Petition for limited proceeding to approve second solar base rate adjustment (SoBRA), effective January 1, 2019 by Tampa Electric Company	**DOCKET NO. 20180133-EI** **FILED: August 23, 2018**

REDACTED

TAMPA ELECTRIC COMPANY'S ANSWERS TO FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NO. 1) OF FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Production of Documents (No. 1) propounded and served on August 9, 2018, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
INDEX TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NO. 1)

Number	Subject	Bates Stamped Pages
1	Please refer to TECO's supplemental response to Staff's First Data Request (filed August 6, 2018), No. 23(h.), page 2 of 2, second to last paragraph of this response. A portion of this response reads: ". . . to the high and low fuel price sensitivities provided by PIRA for the near and mid-term pricing." Please provide a copy of the "high and low fuel price sensitivities provided by PIRA."	1 - 6

1. Please refer to TECO's supplemental response to Staff's First Data Request (filed August 6, 2018), No. 23(h.), page 2 of 2, second to last paragraph of this response. A portion of this response reads: ". . . to the high and low fuel price sensitivities provided by PIRA for the near and mid-term pricing." Please provide a copy of the "high and low fuel price sensitivities provided by PIRA."

A. The requested information is attached.

REDACTED

PIRA SPS Quarterly Update
North American Gas Scenario Price Summary

Henry Hub Constant 2016 $/MMBtu

Year	Reference (SPS 2018)	Low	High
2000	[redacted]		
2001			
2002			
2003			
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			
2013			
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2037			
2038			
2039			
2040			
Avg 2018-40			

REDACTED

PIA SPS Quarterly Update: 2018

COAL PRICE SCENARIOS

Constant 2016$/Ton

NYMEX CAPP ($/mmbtu)	Probability	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(Reference)	50%	[redacted]									
(Low)	30%										
(High)	20%										

ARA CIF ($/mmbtu)		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(Reference)	50%	[redacted]									
(Low)	30%										
(High)	20%										

Nominal$

NYMEX CAPP ($/mmbtu)		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(Reference)	50%	[redacted]									
(Low)	30%										
(High)	20%										

ARA CIF ($/mmbtu)		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(Reference)	50%	[redacted]									
(Low)	30%										
(High)	20%										

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Inflation Index (2015 = 1.0)	[redacted]									

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
STAFF'S FIRST REQUEST FOR PODS
FILED: AUGUST 23, 2018

REDACTED

PIRA SPS Quarterly Update
COAL PRICE SCENARIOS
Constant 2016$/Ton

NYMEX CAPP ($/mmbtu)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(Reference)	[redacted]										
(Low)											
(High)											

ARA CIF ($/mmbtu)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(Reference)	[redacted]										
(Low)											
(High)											

Nominal$

NYMEX CAPP ($/mmbtu)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(Reference)	[redacted]										
(Low)											
(High)											

ARA CIF ($/mmbtu)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(Reference)	[redacted]										
(Low)											
(High)											

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Inflation Index (2015 = 1.0)	[redacted]										

REDACTED

PIRA SPS Quarterly Update
COAL PRICE SCENARIOS

Constant 2016$/Ton

NYMEX CAPP ($/mmbtu)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
(Reference)	[redacted]										
(Low)											
(High)											

ARA CIF ($/mmbtu)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
(Reference)	[redacted]										
(Low)											
(High)											

Nominal$

NYMEX CAPP ($/mmbtu)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
(Reference)	[redacted]										
(Low)											
(High)											

ARA CIF ($/mmbtu)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
(Reference)	[redacted]										
(Low)											
(High)											

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Inflation Index (2015 = 1.0)	[redacted]										

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
STAFF'S FIRST REQUEST FOR PODS
FILED: AUGUST 23, 2018

REDACTED

PIRA SPS Quarterly Update
COAL PRICE SCENARIOS

Constant 2016$/Ton

NYMEX CAPP ($/mmbtu)	2032	2033	2034	2035	2036	2037	2038	2039	2040
(Reference)	[redacted]								
(Low)									
(High)									

ARA CIF ($/mmbtu)	2032	2033	2034	2035	2036	2037	2038	2039	2040
(Reference)	[redacted]								
(Low)									
(High)									

Nominal$

NYMEX CAPP ($/mmbtu)	2032	2033	2034	2035	2036	2037	2038	2039	2040
(Reference)	[redacted]								
(Low)									
(High)									

ARA CIF ($/mmbtu)	2032	2033	2034	2035	2036	2037	2038	2039	2040
(Reference)	[redacted]								
(Low)									
(High)									

	2032	2033	2034	2035	2036	2037	2038	2039	2040
Inflation Index (2015 = 1.0)	[redacted]								

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
STAFF'S FIRST REQUEST FOR PODS
FILED: AUGUST 23, 2018

10

Staff's 2^{nd} Interrogatories Nos. 6-17

Supplemental Response to Nos. 11 & 12

2^{nd} Supplemental Response to No. 12

(See additional files contained on Staff Hearing Exhibit CD/USB for 12, 14 and 17.)

Confidential DN. 06034-2018

(No. 10)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180133-EI EXHIBIT: 10
PARTY: STAFF – (DIRECT)
DESCRIPTION: James Rocha6, 9, 11, 12, 14, 17Mark Ward 7, 8, 10, 13, 15, 16

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Petition for limited proceeding to approve second solar base rate adjustment (SoBRA), effective January 1, 2019 by Tampa Electric Company	**DOCKET NO. 20180133-EI** **FILED: September 13, 2018**

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SECOND SET OF INTERROGATORIES (NOS. 6-17)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 6-17) propounded and served on August 30, 2018, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180133-EI
INDEX TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 6-17)

Number	Witness	Subject	Bates Stamped Page
6	Rocha	Resource Planning. Please refer to TECO's response to Data Request 12. Has TECO taken solar capacity degradation into account in its planning process? If not, why not? If so, please explain the following: a. How degraded capacity values are calculated. b. What assumptions are required for calculating degraded capacity values. c. Was solar degradation is taken into account in TECO's cost-effectiveness evaluation. d. What causes solar capacity degradation. e. Please provide the assumed annual output for each project.	1
7	Ward	**Permitting.** Please refer to TECO's response to Data Request 20. Has the Department of Environmental Protection issued the Environmental Resource Program (ERP) permit for the Lake Hancock project? If not, when is it estimated to be issued?	3
8	Ward	**Commission Noticing.** Please state how TECO plans to inform the Commission that the 2019 solar projects are in-service.	4
9	Rocha	**Cost-Effectiveness.** Please refer to TECO witness Rocha's testimony Page 13, Lines 17 – 19. Please detail the amount the statewide property tax exemption for solar generation impacts each 2019 TECO solar project's annual revenue requirement.	5
10	Ward	**Cost-Effectiveness.** Please refer to Exhibit MDW-1, Document No. 5, Page 3 of 3. Please clarify how the $1,494/kW-ac total installed cost for the Lake Hancock project was calculated. In particular please clarify if the entirety of the 49.5 MW project is accounted for in the total installed cost. a. If the Lake Hancock project Total Installed Cost was calculated at 49.5 MW, please provide a revised Exhibit MDW-1, Document No. 5, Page 3 of 3 that calculates the Total $/kW-ac at 32 MW, with updated "Major Equipment" and	6

		"Balance of System" costs to reflect this change. b. Please explain how the Company divides costs between those sought for recovery through the SoBRA Mechanism and the remaining 17.7 MWs.	
11	Rocha	**Cost-Effectiveness.** Please refer to Exhibit RJR-1, Document Nos. 4 and 5. Please explain why there is a decrease in savings from $14.2 Million to $12.6 Million when the amount of solar increases from 260.3 MW to 278 MW, respectively.	8
12	Rocha	**Cost-Effectiveness.** Please refer to TECO's excel response to Staff Data Requests 12 and 15. a. Please refer to TECO's excel spreadsheet included in its response to Staff's Data Request 15, tab "Q15," row 4 labeled "Capital RR – Other New Units." Detail what "Other News Units" these revenue requirement costs/(savings) represent and provide the individual revenue requirements for them. b. Please reconcile the Company's claimed savings attributed to "Other New Units" with the response that there are no changes in unit additions or retirements.	9
13	Ward	**Cost-Effectiveness.** Please refer to the TECO's response to Staff Data Requests 3 – 7, subparts H. Please detail the amount of allocation of all items included in owners cost (e.g. preliminary geotechnical study and environmental studies, surveys, etc...) by project. For example, detail the Director of Renewables total salary and the allocation of the Director of Renewables salary by project.	10
14	Rocha	**Cost-Effectiveness.** Please refer to TECO's response to Staff Data Request 15. Please provide revised electronic (excel) files for the excel tabs "Q15", "Q15c – High Fuel" and "Q15c – Low Fuel" that corrects the discrepancy between the 29 year period for the "Total w/ CO2 & NOx Cost" to match the 31 year period for the "Sub Total w/o NOx or CO2 Cost".	11
15	Ward	**Cost-Effectiveness.** Please refer to Witness Ward Testimony Page 7, Lines 18 – 23. Please state if TECO plans to seek recovery of the 17.7 MW of the Lake Hancock solar project in a future proceeding. If so, please state what process of recovery TECO would seek.	15

16	Ward	**Cost-Effectiveness.** Please refer to Witness Ward Testimony Page 15, Lines 11 – 16. Please state if TECO expects the steel tariffs to add increase unit costs in future solar projects. a. If so, please state how TECO believes this additional cost will affect the ability to meet the $1,500 per kWac installed cost cap in future proceedings.	16
17	Rocha	**Cost-Effectiveness.** Please refer to EXH RJR-1, Document No. 4. For all planned solar generation, please provide the annual and cumulative values over a 30-year period (in nominal and net present value) for each of the following categories: Equipment and Installation, Incremental Fixed O&M, Fuel Savings, Emissions Savings, separated by type (CO2, etc.), Avoided Replacement Costs, Avoided Capacity Purchases, Avoided Fixed O&M, Avoided Variable O&M and Transmission Upgrades. Please provide this response in electronic (Excel) format. a. Please explain in detail the assumptions used to determine the value of each of the components evaluated in this analysis. b. Please explain whether TECO's emissions savings include CO2 or CO2 equivalent emissions. If so, please provide a sensitivity of the analysis without these costs and provide the revised annual and cumulative values (in nominal and net present value) for each category in electronic (Excel) format. c. Please provide a sensitivity of the fuel savings based upon a low fuel price forecast and a high fuel price forecast, with revised annual and cumulative values (in nominal and net present value) for each category in electronic (Excel) format.	17

Jim Rocha
Director, Planning Strategy and Compliance

Mark Ward
Director, Renewable Energy

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

6. Resource Planning. Please refer to TECO's response to Data Request 12. Has TECO taken solar capacity degradation into account in its planning process? If not, why not? If so, please explain the following:

a. How degraded capacity values are calculated.

b. What assumptions are required for calculating degraded capacity values.

c. Was solar degradation is taken into account in TECO's cost-effectiveness evaluation.

d. What causes solar capacity degradation.

e. Please provide the assumed annual output for each project.

A. Yes.

a. The historical operational data for solar generation is insufficient to forecast degradation based on actual performance. When suppliers provide design data they include an 8760 first-year solar output profile and an average degradation rate to represent the MW_{DC} output over time. Tampa Electric applied a 0.4% degradation rate to the solar output after the first full year of service for each solar site. Tampa Electric's solar sites are designed with more solar panels (MW_{DC}) than the rating of the inverters (MW_{AC}). Therefore, although the maximum MW_{AC} output is degraded, the amount of solar generation able to be sent to the grid would not decrease until the MW_{DC} degrades below the inverter ratings.

b. To take degradation into account Tampa Electric applied the assumptions described in the company's response to part (a).

c. Yes.

d. According to National Renewable Energy Laboratory ("NREL"), solar module performance degrades over time because of unavoidable elements like thermal cycling, damp heat, humidity freeze, and ultraviolet ("UV") exposure. Thermal cycling can cause solder bond failures and cracks in solar cells. Damp heat has been associated with delamination of encapsulants and corrosion of cells. Humidity freezing can cause junction box adhesion to fail. UV exposure contributes to discoloration and back-sheet degradation.

e. The estimated annual output by project is shown in the following table.

Forecasted Solar Generation (GWh)					
	Lithia	Grange Hall	Peace Creek	Bonnie Mine	Lake Hancock (31.8 MW)
2018	-	-	-	-	-
2019	172.1	141.1	128.0	86.6	73.5
2020	171.5	141.0	127.9	86.6	73.4
2021	170.7	140.0	126.9	85.9	72.9
2022	170.0	139.4	126.4	85.6	72.6
2023	169.4	138.9	125.9	85.2	72.3
2024	168.7	138.8	125.9	85.2	72.2
2025	168.0	137.8	124.9	84.6	71.7
2026	167.3	137.2	124.4	84.2	71.4
2027	166.7	136.7	123.9	83.9	71.1
2028	166.1	136.6	123.9	83.8	71.1
2029	165.3	135.6	122.9	83.2	70.6
2030	164.7	135.0	122.4	82.9	70.3
2031	164.0	134.5	122.0	82.6	70.0
2032	163.4	134.4	121.9	82.5	70.0
2033	162.7	133.4	121.0	81.9	69.4
2034	162.0	132.9	120.5	81.6	69.2
2035	161.4	132.4	120.0	81.2	68.9
2036	160.8	132.3	120.0	81.2	68.9
2037	160.1	131.3	119.0	80.6	68.4
2038	159.5	130.8	118.6	80.3	68.1
2039	158.8	130.3	118.1	79.9	67.8
2040	158.3	130.2	118.1	79.9	67.7
2041	157.6	129.2	117.2	79.3	67.3
2042	156.9	128.7	116.7	79.0	67.0
2043	156.3	128.2	116.2	78.7	66.7
2044	155.8	128.1	116.2	78.6	66.7
2045	155.1	127.2	115.3	78.1	66.2
2046	154.4	126.6	114.8	77.7	65.9
2047	153.8	126.1	114.4	77.4	65.6
2048	153.2	125.6	113.9	77.1	65.4

7. **Permitting.** Please refer to TECO's response to Data Request 20. Has the Department of Environmental Protection issued the Environmental Resource Program (ERP) permit for the Lake Hancock project? If not, when is it estimated to be issued?

A. No. Tampa Electric submitted the Environmental Resource Permit ("ERP") application to the Florida Department of Environmental Protection ("FDEP") on June 29, 2018. Tampa Electric has submitted additional information requested by FDEP. The ERP is expected to be issued in late September or early October.

8. **Commission Noticing.** Please state how TECO plans to inform the Commission that the 2019 solar projects are in-service.

A. Tampa Electric will notify the Commission by letter when the projects are in service.

9. **Cost-Effectiveness.** Please refer to TECO witness Rocha's testimony Page 13, Lines 17 – 19. Please detail the amount the statewide property tax exemption for solar generation impacts each 2019 TECO solar project's annual revenue requirement.

A. The statewide property tax exemption for solar generation gives an 80% property tax abatement for non-residential renewable energy property that expires December 31, 2037. This exemption reduces property taxes for the solar projects as follows: Lithia by $10 million, Grange Hall by $8 million, Peace Creek by $7 million, Bonnie Mine by $5 million and Lake Hancock (49.5 MW) by $6 million for a total property tax exemption of $36 million. For 31.8 MW of the Lake Hancock project, instead of the total 49.5 MW, the property tax reduction is $4 million.

REDACTED

10. **Cost-Effectiveness.** Please refer to Exhibit MDW-1, Document No. 5, Page 3 of 3. Please clarify how the $1,494/kW-ac total installed cost for the Lake Hancock project was calculated. In particular please clarify if the entirety of the 49.5 MW project is accounted for in the total installed cost.

a. If the Lake Hancock project Total Installed Cost was calculated at 49.5 MW, please provide a revised Exhibit MDW-1, Document No. 5, Page 3 of 3 that calculates the Total $/kW-ac at 32 MW, with updated "Major Equipment" and "Balance of System" costs to reflect this change.

b. Please explain how the Company divides costs between those sought for recovery through the SoBRA Mechanism and the remaining 17.7 MWs.

A. The $1,494 per kW_{ac} total installed cost is calculated based on the entirety of the Lake Hancock project. The 17.7 MW excluded from the Second SoBRA is separated at this average total installed cost.

a. The requested information is provided in the following table.

Lake Hancock Solar Project (31.8 MWac) Projected Installed Cost by Category

Estimated Costs ($MM)	
Project Output (MW-ac)	31.8
Major Equipment[1]	[redacted]
Balance of System[2]	
Development	
Transmission Interconnect	2.7
Land	5.8
Owners Costs	0.2
Total Installed Cost ($MM)	47.5
AFUDC ($MM)	-
Total All-in-Cost ($MM)	47.5
Total ($/kW-ac)	1,494

[1] Major Equipment includes modules, inverters, and transformers

[2] Balance of System includes racking, posts, collection cables, EPC Contractor and Project Management systems.

b. The Lake Hancock project revenue requirement to include in the SoBRA mechanism was determined using 64.2 percent of the total installed costs for the project. The 64.2 percent was determined as follows:

31.8 MW / 49.5 MW = 64.2%.

This calculation removes the 17.7 MW of the project which exceed the maximum SoBRA recovery MW.

11. **Cost-Effectiveness.** Please refer to Exhibit RJR-1, Document Nos. 4 and 5. Please explain why there is a decrease in savings from $14.2 Million to $12.6 Million when the amount of solar increases from 260.3 MW to 278 MW, respectively.

A. The fuel savings from the additional 17.7 MW of solar generation is included in the cost-effectiveness analysis for both scenarios—260.3 MW and 278 MW. By contrast, the 260.3 MW scenario includes revenue requirements to recover the costs for 260.3 MW, and the 278 MW scenario includes revenue requirements to recover the costs of the full 278 MW. Therefore, the 278 MW cost-effectiveness analysis savings of $12.6 million is lower than the $14.2 million savings for the 260.3 MW scenario because these additional costs are included.

11. **Cost-Effectiveness.** Please refer to Exhibit RJR-1, Document Nos. 4 and 5. Please explain why there is a decrease in savings from $14.2 Million to $12.6 Million when the amount of solar increases from 260.3 MW to 278 MW, respectively.

A. The Lake Hancock project is expected to provide 49.5 MW of solar capacity when completed. Even though there isn't room in the Second SoBRA for all 49.5 MW of the Lake Hancock capacity, Tampa Electric is building all 49.5 MW of the available capacity and plans to place all 49.5 MW in service by January 1, 2019, because doing so accommodates the efficient planning and construction of the project as contemplated in paragraph 6(c) of the 2017 Agreement. As a result, the company's retail customers will receive the fuel benefit from the entire project (49.5 MW) beginning in January 2019, even though only a portion of the total revenue requirement for the project (31.8 MW) will be recovered through the new Second SoBRA rates sponsored by Mr. Ashburn. The approximately 17.7 MW difference referenced in the question is the portion of the Lake Hancock capacity that will not be recovered through the Second SoBRA.

A cost-effectiveness analysis was provided for the 260.3 MW of solar allowed in this Second SoBRA as well as the total 278 MW of solar constructed. The former is shown to prove this Second SoBRA is cost-effective, while the latter is shown to prove the total 278 MW of solar is cost-effective. The 260.3 MW is cost-effective by $14.2 million as shown in Document No. 5; the fuel savings for this case is $324.9 million from 260.3 MW of solar. The 278 MW is cost-effective by $12.6 million as shown in Document No. 4; the fuel savings for this case is $345.7 million from 278 MW of solar. The savings decline from $14.2 million to $12.6 million ($1.6 million) because the fuel savings increase by only $20.8 million while the remaining costs from the additional 17.7 MW increase by $22.4 million.

12. **Cost-Effectiveness.** Please refer to TECO's excel response to Staff Data Requests 12 and 15.

a. Please refer to TECO's excel spreadsheet included in its response to Staff's Data Request 15, tab "Q15," row 4 labeled "Capital RR – Other New Units." Detail what "Other News Units" these revenue requirement costs/(savings) represent and provide the individual revenue requirements for them.

b. Please reconcile the Company's claimed savings attributed to "Other New Units" with the response that there are no changes in unit additions or retirements.

A. a. The savings represented in the response to Staff's Data Request No. 15 under "Other New Units" is a credit given to reflect solar capacity value at the coincident peak. This credit is calculated in the same manner as if a small power production facility came to Tampa Electric for a Standard Offer contract. Although the next unit is not avoided, solar capacity provides value to the system.

b. See the company's response to part (a).

12. **Cost-Effectiveness.** Please refer to TECO's excel response to Staff Data Requests 12 and 15.

a. Please refer to TECO's excel spreadsheet included in its response to Staff's Data Request 15, tab "Q15," row 4 labeled "Capital RR – Other New Units." Detail what "Other News Units" these revenue requirement costs/(savings) represent and provide the individual revenue requirements for them.

b. Please reconcile the Company's claimed savings attributed to "Other New Units" with the response that there are no changes in unit additions or retirements.

A. a. The savings represented in the response to Staff's Data Request No. 15 under "Other New Units" is a credit given to reflect solar capacity value at the coincident peak. This credit is calculated in the same manner as if a small power production facility came to Tampa Electric for a Standard Offer contract. Although the next unit is not avoided, solar capacity provides value to the system.

The monthly firm capacity value employed is shown in the Excel file titled "(BS_9A) 20180133 No 12 Solar Capacity Value.xlsx," tab "Capacity Value," which shows an annual average result of 46.6 percent. This annual average is multiplied by the output of each project in the Excel spreadsheet titled "(BS_9B) 20180133 No 12 Value of Deferral_260.3_CT2023_CT2026.xls" and 0.4% output degradation is applied each year. The credit is calculated in column "N."

b. See the company's response to part (a).

12. **Cost-Effectiveness.** Please refer to TECO's excel response to Staff Data Requests 12 and 15.

a. Please refer to TECO's excel spreadsheet included in its response to Staff's Data Request 15, tab "Q15," row 4 labeled "Capital RR – Other New Units." Detail what "Other News Units" these revenue requirement costs/(savings) represent and provide the individual revenue requirements for them.

b. Please reconcile the Company's claimed savings attributed to "Other New Units" with the response that there are no changes in unit additions or retirements.

A. a. Paragraph 6 of the 2017 Settlement Agreement was intended by the parties to give Tampa Electric an opportunity to build 550 MW of cost-effective solar generation (plus an additional 50 MW as an incentive) over a period of time. The total capacity was divided into three tranches (with an optional fourth) and staged or allocated to future time periods to accommodate orderly construction and to phase in and moderate the rate impact to retail customers. During the negotiations, the company disclosed its plans to purchase the solar modules for the entire 600 MW and then finalized the purchase in 2017. Although the specifics of the cost-effectiveness test contemplated in the 2017 Settlement Agreement are not spelled out in paragraph 6, the way in which the company has apportioned solar capacity value and value of other deferred capacity in its CPVRR calculation is consistent with the way the parties discussed the solar additions in paragraph 6 of the 2017 Settlement Agreement and will have no precedential value beyond Tampa Electric's solar base rate adjustments and the 2017 Settlement Agreement.

Last September, the company calculated the firm solar capacity value of the deferred unit for all 600 MW as \$197.4 million. Additional future unit deferrals in the remainder of that expansion plan were not included in the \$197.4 million. For the First SoBRA the reported value of \$129.5 million in the response to Staff's Third Set of Interrogatories, No. 13, on row 4 and 39 labeled "Capital RR – Other New Units" of tab "Q13" in the Excel file "20170260 Staff's 3rd Set of IRR.xlsx" submitted in Docket No. 20170260-EI, represented \$50.5 million value of deferral for the first unit deferred as well as \$79.0 million for deferred units in the remainder of the expansion plan. The $79.0 million for deferred units in the remainder of the expansion plan is not shared with the other SoBRA tranches. The $197.4 million is shown in the Excel file titled "(BS_9C) 20180133 No 12 Value of Deferral_600_CT2021_CT2024_TR.xlsx" provided with this response.

The Tranche 2 solar projects do not change the expansion plan compared to the base case expansion plan with the Tranche 1 solar projects. Tranche 1 and the full 600 MW did defer future units. Therefore, Tampa Electric made the decision to pro-rate the first unit deferred across all four tranches. The credit shown in row 4 of tab "Q15" in the Excel file provided in response to Staff's Data Request No. 15 derives solely from a value of deferral calculated capacity value of the Tranche 2 solar projects. Only the firm (applies to reserve margin) portion of capacity value provides credit. This calculation is shown as a $78.8 million credit for Tranche 2 in the Excel file titled "(BS_9B) 20180133 No 12 Value of Deferral_260.3_CT2023_CT2026.xls" that was provided in this docket on September 21, 2018.

The Commission can be comfortable that there is no double counting of the assigned capacity values through a high-level proof of the pro-ration. On a per-MW basis, $47.7 million of the $197.4 million would be allocated to Tranche 1, and $85.6 million would be allocated to Tranche 2, for a total of $133.1 million. The actual amounts credited were $50.5 million and $78.8 million for Tranche 1 and Tranche 2, respectively, for a total of $129.3 million.[1] This $129.3 million credited to Tranches 1 and 2 is less than the $133.1 million from the pro-ration, proving there is no double counting. Using these values, both Tranche 1 and Tranche 2 pass the required cost-effectiveness test.

The company calculated these capacity values as a way to prorate the expansion plan savings from the entire 600 MW in the Agreement. It is also the same ratable approach of value of deferral used when evaluating demand-side management programs in Tampa Electric's conservation dockets. This was essential because expansion plan additions are "lumpy," and even 1 MW of Tranche 1 could be the tipping

[1] This $85.6 million proration for Tranche 2 is approximately $7 million greater than the savings included in the Second SoBRA cost-effectiveness analysis because the capital costs of the avoided unit declined from 2017 to 2018.

point to defer an expansion plan addition while Tranche 2 does not, even though it is 80 percent more MW than Tranche 1. To do otherwise would incorrectly benefit Tranche 1 at the expense of the other Tranches and would be inconsistent with the solar capacity addition in the Agreement, which led the company to plan and procure solar equipment.

Solar projects provide capacity value and can contribute to the deferral of the company's next generating unit. For these reasons, Tampa Electric presently uses the same basic approach considering capacity value and value of deferral when evaluating the cost-effectiveness of third-party solar PPA proposals. Doing so provides a consistent basis for evaluation and ensures that third-party solar is evaluated fairly against the company's future self-build options. It is worth noting that the 600 MW is now part of the current base case and any PPA proposals would receive a value of deferral for any unit deferrals compared to this base case.

The approach described in this answer assumes that Tampa Electric will build at least 550 MW of solar projects. Without objection from Tampa Electric, the parties and the Commission may reserve their rights to take appropriate action if at least 550 MW is not built out.

13. **Cost-Effectiveness.** Please refer to the TECO's response to Staff Data Requests 3 – 7, subparts H. Please detail the amount of allocation of all items included in owners cost (e.g. preliminary geotechnical study and environmental studies, surveys, etc...) by project. For example, detail the Director of Renewables total salary and the allocation of the Director of Renewables salary by project.

A. The owner's cost components and their allocations are provided in the following table.

Owner's Costs

	Grange Hall	Lithia	Peace Creek	Bonnie Mine	Lake Hancock
Labor	35%	16%	40%	27%	37%
Outside Services	16%	6%	0%	12%	23%
Consultants - Legal, Safety, ECT	44%	48%	52%	52%	35%
Equipment Rentals	0%	0%	0%	0%	0%
Material/SHI	1%	2%	3%	3%	2%
Permits and Gov't Fees	4%	9%	4%	6%	3%
Insurance	0%	20%	0%	0%	0%
Total	100%	100%	100%	100%	100%

The primary responsibility of the Director of Renewables is to provide management oversight of Tampa Electric's utility scale solar program, which includes the 10 projects that comprise 600 MW_{ac} of SoBRA solar projects. The Director of Renewables spends approximately 80 percent of his time managing the SoBRA projects. The allocation by project is shown in the following table.

Director of Renewables Salary Allocation

Tranche 2 SoBRA Projects	
Grange Hall	7.8%
Lithia	7.8%
Peace Creek	7.8%
Bonnie Mine	7.8%
Lake Hancock	7.8%
Tranche 1, 3 and 4 SoBRA Projects	40.0%
Administrative and Other	21.0%
Total	100.0%

14. **Cost-Effectiveness.** Please refer to TECO's response to Staff Data Request 15. Please provide revised electronic (excel) files for the excel tabs "Q15", "Q15c – High Fuel" and "Q15c – Low Fuel" that corrects the discrepancy between the 29 year period for the "Total w/ CO2 & NOx Cost" to match the 31 year period for the "Sub Total w/o NOx or CO2 Cost".

A. Please reference the Excel file "(BS14) 20180133 Staff Second Interrogatories No 14.xlsx", tabs "Q14," "Q14 – High Fuel," and "Q14 – Low Fuel" for the addition of one year of emissions savings to address the full 30-year life of the assets.

COST-EFFECTIVENESS TEST FOR SECOND SOBRA
(Based on the 260.3 MW Included in the Second SoBRA)

Delta CPVRR Revenue Requirements - **Base Fuel Sensitivity**	Cost/(Savings) (2018 US $ millions)
Capital RR - Other New Units	($78.8)
Capital RR - Solar New Arrays (w/Interconnect)	$326.7
RR of Land for Solar	$61.2
System VOM	($19.2)
FOM - Other Future Units	($0.0)
FOM - Solar Future Arrays	$29.9
System Fuel	($324.9)
System Capacity	($9.1)
Sub Total w/o NO_X or CO_2 Cost	($14.2)
Plus Emissions Costs	
CO_2 - Base	($25.3)
CO_2 - High	($91.0)
CO_2 - Low	$0.0
NO_X - Base	($1.1)
Total w/ CO_2 (Base) & NO_X Cost	($40.5)
Total w/ CO_2 (High) & NO_X Cost	($106.2)
Total w/ CO_2 (Low) & NO_X Cost	($15.2)

COST-EFFECTIVENESS TEST FOR SECOND SOBRA
(Based on the 260.3 MW Included in the Second SoBRA)

Delta CPVRR Revenue Requirements - **High Fuel Sensitivity**	Cost/(Savings) (2018 US $ millions)
Capital RR - Other New Units	($78.8)
Capital RR - Solar New Arrays (w/Interconnect)	$326.7
RR of Land for Solar	$61.2
System VOM	($15.1)
FOM - Other Future Units	($0.0)
FOM - Solar Future Arrays	$29.9
System Fuel	($458.0)
System Capacity	($9.1)
CPVRR w/o NO_X or CO_2 Cost	($143.1)
Plus Emissions Costs	
CO_2 - Base	($24.8)
CO_2 - High	($86.5)
CO_2 - Low	$0.0
NO_X - Base	($0.9)
Total w/ CO_2 (Base) & NO_X Cost	($168.9)
Total w/ CO_2 (High) & NO_X Cost	($230.6)
Total w/ CO_2 (Low) & NO_X Cost	($144.1)

COST-EFFECTIVENESS TEST FOR SECOND SOBRA
(Based on the 260.3 MW Included in the Second SoBRA)

Delta CPVRR Revenue Requirements - **Low Fuel Sensitivity**	Cost/(Savings) (2018 US $ millions)
Capital RR - Other New Units	($78.8)
Capital RR - Solar New Arrays (w/Interconnect)	$326.7
RR of Land for Solar	$61.2
System VOM	($20.5)
FOM - Other Future Units	($0.0)
FOM - Solar Future Arrays	$29.9
System Fuel	($233.8)
System Capacity	($9.1)
CPVRR w/o NO_X or CO_2 Cost	$75.6
Plus Emissions Costs	
CO_2 - Base	($26.3)
CO_2 - High	($93.8)
CO_2 - Low	$0.0
NO_X - Base	($1.2)
Total w/ CO_2 (Base) & NO_X Cost	$48.1
Total w/ CO_2 (High) & NO_X Cost	($19.5)
Total w/ CO_2 (Low) & NO_X Cost	$74.4

15. **Cost-Effectiveness.** Please refer to Witness Ward Testimony Page 7, Lines 18 – 23. Please state if TECO plans to seek recovery of the 17.7 MW of the Lake Hancock solar project in a future proceeding. If so, please state what process of recovery TECO would seek.

A. In accordance with Tampa Electric's 2017 Settlement Agreement, the company will not recover these revenue requirements in the Second SoBRA but will include the costs of the 17.7 MW of solar generation in surveillance reporting. The 17.7 MW excluded from recovery are from the company's highest-priced SoBRA project, cost-effective, and below the $1,500 per kW_{ac} cost cap requirement in the agreement.

Tampa Electric may use the 17.7 MW of solar generation in a community solar program. The program will be a cost-effective, voluntary program for customers who are interested in using renewable energy but do not have the opportunity or desire to install PV panels on their rooftops. The company is developing the community solar program and will submit it to the Commission for approval. The implementation date of the community solar program has not been determined but would likely be several months after the Second SoBRA projects are fully operational as customer enrollment and programming efforts will be required once the program is approved. If the community solar program is not approved, then at the time that the company submits its petition for its third tranche of solar projects it would include the depreciated net book value of the 17.7 MW.

Customers will begin receiving fuel savings from the incremental 17.7 MW of solar generation when the project is fully operational, even though the project costs will not be recovered until a later date.

16. **Cost-Effectiveness.** Please refer to Witness Ward Testimony Page 15, Lines 11 – 16. Please state if TECO expects the steel tariffs to add increase unit costs in future solar projects.

a. If so, please state how TECO believes this additional cost will affect the ability to meet the $1,500 per kWac installed cost cap in future proceedings.

A. Yes.

a. Steel import tariffs will increase unit costs in future solar projects. As stated in witness Ward's testimony, Tampa Electric estimates the cost impact of steel tariffs on SoBRA project costs is $20 to $30 per kW_{ac} per project. The additional cost from the steel import tariffs will be absorbed in project contingency and may result in project costs greater than first estimated. Currently, all remaining projects are expected to meet the $1,500 per kW_{ac} installed cost cap, including the cost impact of the steel import tariffs.

17. **Cost-Effectiveness.** Please refer to EXH RJR-1, Document No. 4. For all planned solar generation, please provide the annual and cumulative values over a 30-year period (in nominal and net present value) for each of the following categories: Equipment and Installation, Incremental Fixed O&M, Fuel Savings, Emissions Savings, separated by type (CO2, etc.), Avoided Replacement Costs, Avoided Capacity Purchases, Avoided Fixed O&M, Avoided Variable O&M and Transmission Upgrades. Please provide this response in electronic (Excel) format.

a. Please explain in detail the assumptions used to determine the value of each of the components evaluated in this analysis.

b. Please explain whether TECO's emissions savings include CO2 or CO2 equivalent emissions. If so, please provide a sensitivity of the analysis without these costs and provide the revised annual and cumulative values (in nominal and net present value) for each category in electronic (Excel) format.

c. Please provide a sensitivity of the fuel savings based upon a low fuel price forecast and a high fuel price forecast, with revised annual and cumulative values (in nominal and net present value) for each category in electronic (Excel) format.

A. Please reference the Excel file titled "(BS19) 20180133 Staff Second Interrogatories No 17.xlsx."

a. A description of the Second SoBRA solar equipment and installation costs and transmission interconnect costs is provided in the direct testimony of Mark Ward, at pages 9 – 11. Each project's cost is reported by component in his Exhibit No. MDW-1, and the cost components for 31.8 MW of the Lake Hancock project (instead of the full 49.5 MW) are shown in the company's response to Interrogatory No. 10.

The fixed O&M costs for the solar projects are assumed to be $7 per kW-year. Fuel savings are calculated by the production cost model Planning and Risk and are based the fuel forecast and load presented in Mr. Rocha's direct testimony. The CO_2 price forecast used in the cost-effectiveness analysis for the second tranche of solar was purchased from a global consulting services company, ICF International, Inc., and developed in the third quarter of 2017. The NO_X price forecast is estimated using an actual sale of Tampa Electric's NO_X Ozone Season allowances in 2016, at $170 per ton, and escalated by one percent a year after 2017. The company's response to Interrogatory No. 12 describes the calculation of avoided replacement costs. Capacity purchases are modeled to maintain reserve margin reliability and are based on market prices. Tampa Electric updates its unit assumptions every year after the Ten Year Site Plan filing, including variable O&M costs. These updated unit assumptions are used in the company's analyses through the preparation of the next Ten Year Site Plan.

b. Tampa Electric's cost-effectiveness analysis results do not include emissions savings. However, the emissions savings are included for informational purposes.

c. See the Excel file titled "(BS19) 20180133 Staff Second Interrogatories No 17.xlsx," tabs "Q17 – High Fuel" and "Q17 – Low Fuel."

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is a Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (Nos. 6-17) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 12th day of September, 2018.

Penelope Rusk
____

Sworn to and subscribed before me this 12th day of September, 2018.

Cynthia R. Kyle
____

Notary Public State of Florida
Cynthia R Kyle
My Commission FF 197516
Expires 03/01/2019

My Commission expires ________________________

EXHIBIT NO. __11__

DOCKET NO: 20180133--EI

WITNESS:

PARTY: PSC

DESCRIPTION: Stipulations

DOCUMENTS:

PROFFERED BY:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180133-EI EXHIBIT: 11
PARTY: All
DESCRIPTION: Stipulations

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for limited proceeding to approve second solar base rate adjustment (SoBRA), effective January 1, 2019, by Tampa Electric Company.	DOCKET NO. 20180133-EI

Stipulations

VII. BASIC POSITION

Tampa Electric seeks approval of its Second Solar Base Rate Adjustment ("SoBRA") consistent, and in accordance with the 2017 Agreement. The 2017 Agreement is a carefully negotiated agreement – unique to Tampa Electric - that reflects a delicate balance of gives and takes among the parties, and which contains a collection of individual provisions that absent the others would likely not be acceptable to some or all of the parties if presented on a stand-alone basis. Paragraph 6, which authorizes a series of SoBRAs, is one such provision. Paragraph 9, which required Tampa Electric to make a one-time tax reform revenue requirement reduction of over $100 million effective January 2019 is another. There are many others.

The Parties to this docket have conducted extensive formal and informal discovery into the company's proposed Second SoBRA, whether it conforms to the unique aspects of the company's SoBRAs as intended by the parties and to ensure that the company met its burden of proof. Although OPC and FIPUG would not agree – absent the 2017 Agreement and its significant benefits to customers - to the kind of base rate increases proposed by the company in this docket, a deal is a deal. The company has shown by a preponderance of the evidence that the Second SoBRA projects are projected below the per project installed cost cap and are cost effective as specified and intended in the 2017 Agreement, and in the specific circumstances of this case, are otherwise prudent for Tampa Electric, regardless of the requirements of the Settlement. Accordingly, the Commission should (1) accept and adopt the stipulations of the parties on Issues 1 through 8, below, and (b) approve the Petition and the five proposed projects which comprise Tampa Electric's Second SoBRA pursuant to the 2017 Agreement approved by the Commission in Order No. PSC-2017-0456-S-EI. The parties intend that doing so will have no precedential value beyond this case and the 2017 Agreement.

Upon approval of the Second SoBRA, and with its tax reform rate reduction, both effective in January 2019, Tampa Electric will have among the lowest retail rates in Florida.

VIII. ISSUES AND POSITIONS

ISSUE 1: **Are the 2019 SoBRA projects proposed by TECO each eligible in their entirety for treatment pursuant to paragraph 6 of the 2017 Agreement?**

Yes. The 2019 SoBRA projects totaling 260.3 MW proposed by TECO each meet in their entirety all of the eligibility requirements for treatment pursuant to paragraph 6 of the 2017 Agreement.

250 MW of this total is the base amount of capacity specified in paragraph 6(b) of the 2017 Agreement.

5.3 MW is allowable in the Second SoBRA as unused capacity carried forward from the First SoBRA.

The remaining 5 MW is the 2% variance specified in paragraph 6(c) of the 2017 Agreement and is allowable for two reasons. First, building all 49 MW of the Lake Hancock project capacity, but including only 32 MW of that capacity in the Second SoBRA, accommodates efficient planning and construction of the Lake Hancock project that includes the projected delivery of greater fuel savings from the entire project. Second, the company has committed that if the 2019 actual annual fuel savings available to the general body of rate payers from the incremental 5 MW and additional 17.7 MW not included in the Second SoBRA does not equal or exceed $1.0 million, it will refund the shortfall to the general body of rate payers using the SoBRA true-up process in paragraph 6 of the 2017 Agreement.

ISSUE 2: **Are the 2019 SoBRA projects proposed by TECO cost effective pursuant to subparagraph 6(g) of the 2017 Agreement?**

Yes. Paragraph 6 of the 2017 Settlement Agreement was intended by the parties to give Tampa Electric an opportunity to build 550 MW of cost-effective solar generation (plus an additional 50 MW if certain requirements are met) over a period of time. The total capacity was divided into three tranches (with an optional fourth) and staged or allocated to future time periods to accommodate orderly construction and to phase in and moderate the rate impact to retail customers. During the negotiations, the company disclosed its plans to purchase the solar modules for the entire 600 MW and then finalized the purchase in 2017. Although the specifics of the cost-effectiveness test contemplated in the 2017 Settlement Agreement are not spelled out in paragraph 6, the way in which the company has apportioned solar capacity value and value of other deferred capacity in its cumulative present value of revenue requirement ("CPVRR") calculation is consistent with the way the parties discussed the solar additions in paragraph 6 of the 2017 Settlement Agreement and will have no precedential value beyond Tampa Electric's solar base rate adjustments and the 2017

Settlement Agreement. The cost-effectiveness test in this case is unique to Tampa Electric.

Solar projects provide capacity value and can contribute to the deferral of the company's next generating unit. For these reasons, Tampa Electric now uses the same basic approach considering capacity value and value of deferral when evaluating the cost-effectiveness of third-party solar PPA proposals. Doing so provides a consistent basis for evaluation and ensures that third-party solar is evaluated fairly against the company's future self-build options. The 600 MW is now part of the current base case and any PPA proposals would receive a value of deferral for any unit deferrals compared to this base case.

Based on the company's plans to build at least 550 MW of solar and as described in the answer to Staff's Interrogatory 12A (revised September 27, 2018), the five projects covered by the Second SoBRA lower the company's projected system CPVRR as compared to such CPVRR without the solar projects; therefore, the projects covered by the Second SoBRA satisfy the cost-effectiveness test in the 2017 Agreement. Without objection from Tampa Electric, the parties and the Commission have reserved or may reserve their rights to take appropriate action if at least 550 MW is not built out.

ISSUE 3: **Are the projected installed costs of each of the 2019 SoBRA projects proposed by TECO less than or equal to the Installed Cost Cap of $1,500 per kW_{ac} pursuant to subparagraph 6(d) of the 2017 Agreement?**

Yes. The projected installed costs of the five projects are as follows:

Project Name	Projected Installed Cost (per kW_{ac})
Lithia Solar	$1,494
Grange Hall Solar	$1,437
Peace Creek Solar	$1,492
Bonnie Mine Solar	$1,464
Lake Hancock Solar	$1,494

These installed costs are lower than the $1,500 per kW_{ac} Installed Cost Cap pursuant to subparagraph 6(d) of the 2017 Agreement.

ISSUE 4: **Is the projected average capital cost of the 2018 and 2019 SoBRA projects proposed by TECO less than or equal to $1,475 per kW_{ac} pursuant to subparagraph 6(c) of the 2017 Agreement?**

Yes. The projected average capital cost of the 2018 and 2019 SoBRA projects is less than or equal to $1,475 per kW_{ac} pursuant to subparagraph 6(c) of the 2017 Agreement.

ISSUE 5: **What are the estimated annual revenue requirements associated with TECO's 2019 SoBRA projects?**

Considering the explanation of, and assurances regarding, the 2% variance specified in Issue 1, the estimated annual revenue requirement associated with Tampa Electric's 2019 SoBRA projects is $46,045,000 including the incentive specified in the 2017 Agreement. This amount is calculated using the projected installed costs of the five projects and in accordance with the revenue requirement cost recovery provisions of the 2017 Agreement.

ISSUE 6: **What are the appropriate base rates needed to collect the estimated annual revenue requirement for the solar projects in the 2019 SoBRA?**

Considering the explanation of, and assurances regarding, the 2% variance specified in Issue 1, the appropriate base rates needed to collect the estimated annual revenue requirement for the solar projects in the 2019 SoBRA are those reflected in the redlined and clean tariffs set forth as Documents Nos. 6 and 7 of witness Ashburn's Exhibit No. ___ (WRA-1, revised September 24, 2018), which are incorporated herein by reference.

ISSUE 7: **Should the Commission approve the tariffs for TECO reflecting the base rate increases for the 2019 projects determined to be appropriate in these proceedings?**

Yes. Considering the explanation of, and assurances regarding, the 2% variance specified in Issue 1, the Commission should approve the revised tariffs for Tampa Electric reflecting the base rate increases for the 2019 projects comprising the company's Second SoBRA effective with the first meter reading in January 2019.

ISSUE 8: **Should the docket be closed?**

Yes. Once all issues in this docket are resolved, the docket should be closed.