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 1, 2019

VIA: ELECTRONIC FILING

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

Re: Tampa Electric Company's 2019 Ten-Year Site Plan

Dear Mr. Teitzman:

Attached for filing on behalf of Tampa Electric Company is the company's January 2019 to December 2028 Ten-Year Site Plan.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2019 to December 2028

Submitted to: Florida Public Service Commission
April 1, 2019

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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
	RT	=	Planned Retirement
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) 2019 Ten-Year Site Plan (TYSP) features plans to enhance electric generating capability as part of our efforts to meet projected incremental resource needs for 2019 through 2028. The 2019 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.

TEC added 144.7 MW_{AC} of solar photovoltaic (PV) on two sites in September 2018 for a system total of 167 MW_{AC} of solar capacity; that total will increase to 445 MW_{AC} of solar PV in 2019 and nearly 647 MW_{AC} of solar PV by 2021. By 2023, the Big Bend modernization project will result in the repowering of Unit 1 into a highly efficient combined cycle unit and the retirement of Unit 2. Additionally, TEC will add simple cycle combustion turbines in January 2023 and January 2026 to meet firm reserve margin requirements.

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 an economical combination of Demand Side Management (DSM), conservation, renewable energy, purchased power, and generation capacity additions. The resource additions in TEC's 2019 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 energy 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

TEC has three (3) generating stations that include steam units, combined cycle units, combustion turbine peaking units, and an integrated coal gasification combined cycle unit. Additionally, TEC has 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 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.

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. Polk 2 Combined Cycle utilizes four (4) natural gas-fired combustion turbines (formerly Polk 2-5 simple cycle CT's), four (4) HRSGs and one (1) steam turbine. Two of the combustion turbines can also be fired with distillate oil.

Solar

TEC owns a 1.6 MW_{AC} fixed tilt solar PV rooftop canopy array located atop the south parking garage at Tampa International Airport, a 1.4 MW_{AC} fixed tilt solar PV ground canopy array located at LEGOLAND® Florida, and a 19.4 MW_{AC} single axis tracking Big Bend Solar Station located at Big Bend Power Station. The 70.3 MW_{AC} Payne Creek Solar and 74.4 MW_{AC} Balm Solar Stations were placed in service in September 2018. In addition, TEC will place in service 278 MW_{AC} of single axis tracking PV solar in 2019.

Schedule 1

Existing Generating Facilities
As of December 31, 2018

(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
Payne Creek Solar		**Polk Co.**											
	1	**25,26/32S/23E**	PV	SOLAR	NA	NA	NA	NA	09/18	**	70,300	70.3	70.3
		30/32S/24E											
Balm Solar		**Hillsborough Co.**											
	1	**19,20/31S/21E**	PV	SOLAR	NA	NA	NA	NA	09/18	**	74,400	74.4	74.4
Solar Total											**167,500**	**167**	**167**
											TOTAL	**4,960**	**5,363**

Notes:

* Limited by environmental permit

** Undetermined

*** Plant firm net capability will be limited effective January 2023

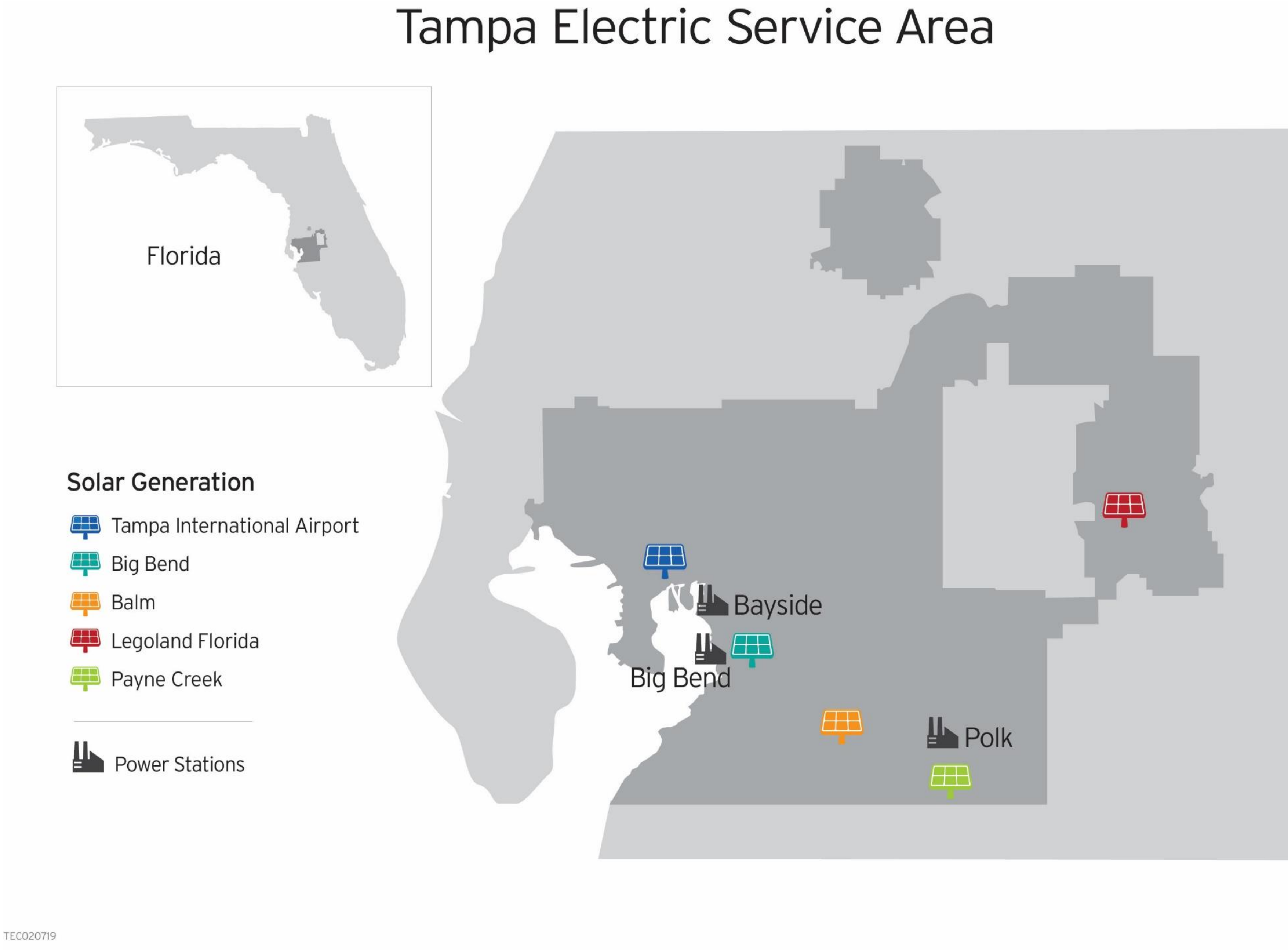

Figure I-1: Tampa Electric Service Area Map

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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 2019-2028 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the 2019-2028 time period.

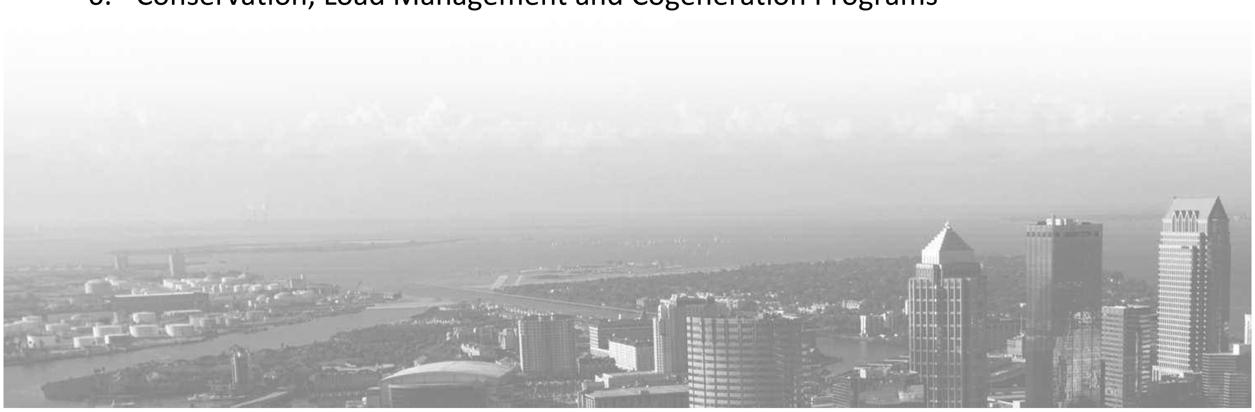
RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2019-2028 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 and demand. 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.

   Commercial Customer Model: Total commercial customers include commercial customers plus temporary service customers (construction sites); therefore, two models are used to forecast total commercial customers:

2. The Commercial Customer Model 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.

3. Projections of permits in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the Temporary Service Model projects the number of customers as a function of new construction permits.

   Industrial Customer Model (Non-Phosphate): Non-phosphate industrial customers include two rate classes that have been modeled individually: General Service and General Service Demand.

4. The General Service Customer Model is a function of Hillsborough County commercial employment.

5. The General Service Demand Customer Model is a function of employment in the manufacturing sector as well as recent trends.

6. *Public Authority Customer Model:* Customer projections are based on the recent growth trends in the governmental sector and are modeled individually for three rate classes: Residential Service, General Service and General Service Demand

    a. The <u>Residential Service Customer</u> Model is a function of recent trends.

    b. The General Service Customer Model is a function of governmental employment.

    c. The General Service Demand Model is a function of governmental employment, as well.

7. *Street & Highway Lighting Customer Model:* Customer projections are based on the recent growth trends in the sector.

3. Energy Multiregression Model

There are a total of nine energy models. All these models represent average usage per customer (kWh/customer), except for the temporary services and lighting models which represent 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:

$$\textbf{HeatEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_y \; / \; \text{Efficiency}_y}{\text{Saturation}_{\text{base y}} \; / \; \text{Efficiency}_{\text{base y}}} \right)$$

$$\textbf{CoolEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_y \; / \; \text{Efficiency}_y}{\text{Saturation}_{\text{base y}} \; / \; \text{Efficiency}_{\text{base y}}} \right)$$

$$\textbf{OtherEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_y \; / \; \text{Efficiency}_y}{\text{Saturation}_{\text{base y}} \; / \; \text{Efficiency}_{\text{base y}}} \right)$$

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.

$$\textbf{HeatUse}_{\mathbf{y,m}} =$$

$$\left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base } y,m}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base } y,m}} \right)^{.17} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base } y,m}} \right)^{.15} \times \left(\frac{\text{HDD}_{y,m}}{\text{Normal HDD}} \right)$$

$$\textbf{CoolUse}_{\mathbf{y,m}} =$$

$$\left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base } y,m}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base } y,m}} \right)^{.17} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base } y,m}} \right)^{.15} \times \left(\frac{\text{CDD}_{y,m}}{\text{Normal CDD}} \right)$$

$$\textbf{OtherUse}_{\mathbf{y,m}} =$$

$$\left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base } y,m}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base } y,m}} \right)^{.17} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base } y,m}} \right)^{.15} \times \left(\frac{\text{Billing Days}_{y,m}}{\text{Billing Days}_{\text{base } y,m}} \right)$$

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.

Commercial Energy Models: total commercial energy sales include commercial sales plus temporary service sales (construction sites); therefore, two models are used to forecast total commercial energy sales.

2. 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.

3. 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 along with the number of days billed, cooling and heating degree-days.

Industrial Energy Model (Non-Phosphate): Non-phosphate industrial energy includes two rate classes that have been modeled individually: General Service and General Service Demand.

4. 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.

5. 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.

Public Authority Sector Model: The governmental sector is modeled individually for three rate classes: Residential Service, General Service and General Service Demand.

6. The Residential Service Customer Model is based on the residential equipment saturation and efficiency assumptions used in the residential model, along with a projection of the customers in this rate class.

7. The General Service Customer Model 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.

8. The General Service Demand Model is a function of commercial output, as well as cooling and heating degree-days.

9. *Street & Highway Lighting Sector Model:* The street and highway lighting sector is not weather sensitive; 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 authority sector. The street and highway lighting forecast reflects the impacts of the company's LED lighting program.

The nine 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 conservation 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 2018, 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 (Conservation Street and Outdoor Lighting Conversion Program which will convert the remaining Metal Halide and High Pressure Sodium technology the company has to Light Emitting Diode technology). Also, in 2018, the company continued the process with all the other FEECA utilities in 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 in an organized setting and electric vehicles at participating high schools. 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 encourages 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.

33. Street and Outdoor Lighting Conversion – a program that recovers the remaining net book value for converting the company's existing metal halide and high pressure sodium street and outdoor luminaires to light emitting diode technology.

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 2018 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	1,177.8%
2016	7.7	4.1	187.8%	5.1	1.6	318.8%	13.2	3.5	377.1%
2017	6.9	5.2	132.7%	4.7	2.2	213.6%	14.9	4.8	310.4%
2018	8.0	6.5	123.0%	5.6	2.7	205.7%	17.1	6.1	280.3%
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	575.0%	10.4	2.7	385.2%	30.2	8.0	377.5%
2018	13.0	1.7	767.1%	15.0	3.3	453.6%	33.7	9.2	365.9%
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	236.8%	15.1	4.9	308.2%	45.1	12.8	352.3%
2018	21.0	8.2	256.5%	20.5	6.0	342.1%	50.8	15.3	331.8%
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 2019-2028. The average annual population growth rate is expected to be 1.7%.

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 (2019-2028), employment is assumed to rise at a 1.1% 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 2019-2028. 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 2019-2028, 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 2019-2028, retail energy sales are projected to rise at a 1.1% annual rate. The major contributors to growth include the residential and governmental categories, increasing at an annual rate of 1.5% and 1.6%, 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 2019-2028, 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.

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.

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.

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 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 system cost.

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, including interconnection costs, 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, the company's expansion plans include the addition of approximately 455 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, and 17.5 MW_{AC} of Shared Solar. Additionally, TEC will modernize Big Bend by first installing simple cycle 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 and DSM programs that may replace or delay the scheduled units. Such optimizations must achieve the overall objective of providing reliable power in a 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 a 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, U.S. Energy Information Administration, 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.

TEC RENEWABLE RESOURCES AND STORAGE TECHNOLOGY INITIATIVES

1. Renewable Energy Initiatives

Since being approved as a permanent Renewable Energy Program by the Commission in Docket No. 060678-EG, Order No. PSC-06-1063-TRF-EG, issued December 26, 2006, TEC has offered the Renewable Energy Program which 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 2018, TEC’s Renewable Energy Program has 1,500 customers purchasing over 2,100 blocks of renewable energy each month and there have been over 4,700 one-time blocks purchased since the program’s inception.

The company’s renewable-generation portfolio is a mix of various technologies and renewable generating sources, including smaller, company-owned photovoltaic (PV) arrays totaling 176 kW_{AC} and an increasing number of large-scale PV systems that provide ample solar kWh for the Renewable Energy Block Program. The smaller, community-sited PV arrays are installed at the Museum of Science and Industry, Walker Middle and Middleton High schools, Tampa Electric’s Manatee Viewing Center, Tampa’s Lowry Park Zoo, the Florida Aquarium, LEGOLAND Florida’s Imagination Zone, and a new 60 kW_{AC} array energized in December 2018. This newest PV array is located at the Florida Conservation and Technology Center (FCTC), an environmental and energy education facility located in Apollo Beach.

The Renewable Energy Program installations are strategically located throughout the community and are designed to educate students and the public on the benefits of renewable energy. Educational signage tout the advantages of solar energy and interactive displays provide hands-on experience to engage visitors’ interest in clean, renewable technologies.

The Renewable Energy Program is projecting to fund an exciting PV project for solar powered street lighting in a newly built community in 2019. In addition to these smaller arrays, the company is planning on installing a number of PV arrays that will provide solar powered charging stations for small electronics (cell phones, tablets) in a highly visited location.

TEC continually analyzes renewable energy alternatives with the objective to integrate them into our generation portfolio as well as provide choices on their program and energy preferences. In late 2018, TEC filed for a 17.5 MW_{AC} Shared Solar Program that is slated to go live in 2019, providing another choice for customers unable to install rooftop solar but prefer their energy generated from solar.

In September 2017, TEC announced the Company’s plans to install an additional 600 MW_{AC} at ten new sites by January 2021, which is enough electricity to power more than 100,000 homes. When the projects are complete, TEC will have 827 watts per customer of solar capacity and over 7 percent of TEC’s generation will come from the sun. The first two project sites, Payne Creek Solar and Balm Solar, went in service in September 2018 with the ability to generate 144.7 MW_{AC} of clean, renewable energy for more than 22,000 homes. The solar additions will significantly reduce Tampa Electric's carbon dioxide emissions and give customers the benefit of zero fuel-cost solar generation for years to come.

As market conditions continue to change and technology improves in this sector, renewable alternatives, such as solar, become more cost-effective to our customers. Rooftop solar is currently cost-effective for some of our customers. Through December 2018, more than 3,000 customers installed PV systems on their homes or businesses, accounting for more than 26 MW_{AC} of net metered, distributed solar generation interconnected on TEC's grid.

2. Storage Technology Initiatives

Battery storage costs have declined over the last few years and are expected to continue to decline in the future. In 2019, a 12.6 MW lithium-ion energy storage system (ESS) will be installed at TEC's Big Bend Solar site after all applicable approvals are received. The ESS will be AC coupled with the solar array and will charge via solar. Several of the expected project benefits include firming of the solar output during peak times and contribution to contingency reserves. TEC will continue to analyze storage technology and its applications with the objective to integrate these resources into our portfolio.

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 firm 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 firm reserve margin employs an industry accepted method of using total available generating capacity 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, and 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 8.1 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
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	1,408,864	2.6	9,418	670,517	14,046	6,266	74,895	83,664
2019	1,437,616	2.6	9,396	681,322	13,792	6,229	75,304	82,721
2020	1,469,414	2.6	9,551	695,011	13,742	6,266	75,612	82,875
2021	1,497,480	2.6	9,685	707,997	13,680	6,297	75,861	83,006
2022	1,524,883	2.5	9,851	720,760	13,668	6,340	76,210	83,190
2023	1,551,660	2.5	9,991	733,249	13,626	6,394	76,600	83,473
2024	1,577,725	2.5	10,135	745,420	13,596	6,452	76,916	83,880
2025	1,603,001	2.5	10,280	757,236	13,575	6,509	77,155	84,366
2026	1,627,470	2.5	10,427	768,684	13,564	6,570	77,375	84,911
2027	1,651,067	2.5	10,573	779,733	13,560	6,632	77,612	85,452
2028	1,673,898	2.5	10,729	790,431	13,574	6,698	77,879	86,007

Notes:
December 31, 2018 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.1

History and 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
2019	1,450,853	2.6	9,457	684,648	13,813	6,237	75,393	82,725
2020	1,490,198	2.6	9,675	701,814	13,786	6,282	75,794	82,882
2021	1,526,112	2.6	9,876	718,425	13,746	6,321	76,139	83,017
2022	1,561,669	2.6	10,111	734,958	13,757	6,373	76,589	83,205
2023	1,596,900	2.6	10,323	751,360	13,739	6,436	77,083	83,493
2024	1,632,926	2.6	10,541	767,581	13,732	6,503	77,506	83,906
2025	1,668,521	2.6	10,762	783,579	13,734	6,571	77,856	84,397
2026	1,703,595	2.6	10,988	799,337	13,747	6,642	78,192	84,945
2027	1,738,117	2.6	11,217	814,818	13,766	6,715	78,547	85,492
2028	1,772,009	2.6	11,457	830,065	13,803	6,793	78,935	86,053

Notes:
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.1

History and 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
2019	1,422,698	2.6	9,336	677,996	13,770	6,222	75,216	82,717
2020	1,447,053	2.5	9,427	688,241	13,697	6,251	75,432	82,867
2021	1,467,456	2.5	9,497	697,671	13,613	6,273	75,586	82,995
2022	1,486,972	2.5	9,597	706,769	13,578	6,308	75,838	83,174
2023	1,486,972	2.4	9,669	715,490	13,513	6,353	76,127	83,453
2024	1,504,516	2.4	9,743	723,797	13,461	6,401	76,340	83,855
2025	1,521,096	2.4	9,816	731,657	13,417	6,449	76,473	84,337
2026	1,536,709	2.3	9,891	739,067	13,383	6,500	76,586	84,876
2027	1,551,307	2.3	9,963	746,001	13,356	6,552	76,713	85,414
2028	1,565,002	2.3	10,043	752,512	13,346	6,608	76,868	85,963

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				Street &	Other Sales	Total Sales
			Average KWH	Railroads	Highway	to Public	to Ultimate
			Consumption	and Railways	Lighting	Authorities	Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH **	GWH	GWH
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	2,014	1,588	1,268,262	0	0	1,933	19,631
2019	1,850	1,597	1,158,519	0	0	2,007	19,482
2020	1,789	1,606	1,114,000	0	0	2,028	19,634
2021	1,820	1,614	1,127,539	0	0	2,048	19,851
2022	1,739	1,623	1,071,315	0	0	2,072	20,002
2023	1,757	1,632	1,077,060	0	0	2,105	20,247
2024	1,763	1,639	1,075,544	0	0	2,143	20,493
2025	1,781	1,647	1,081,393	0	0	2,181	20,751
2026	1,785	1,654	1,079,528	0	0	2,222	21,004
2027	1,803	1,661	1,085,610	0	0	2,264	21,273
2028	1,823	1,667	1,093,280	0	0	2,307	21,557

Notes:
December 31, 2018 Status
*Average of end-of-month customers for the calendar year.
**Sales shown 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

History and Forecast of Energy Consumption and Number of Customers by Customer Class High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				Street &	Other Sales	Total Sales
			Average KWH Consumption	Railroads and Railways	Highway Lighting	to Public Authorities	to Ultimate Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH **	GWH	GWH
2019	1,853	1,597	1,160,059	0	0	2,016	19,563
2020	1,795	1,606	1,117,388	0	0	2,046	19,797
2021	1,829	1,616	1,132,045	0	0	2,076	20,102
2022	1,751	1,625	1,077,774	0	0	2,109	20,345
2023	1,773	1,633	1,085,786	0	0	2,152	20,684
2024	1,783	1,641	1,086,348	0	0	2,201	21,028
2025	1,804	1,649	1,094,046	0	0	2,251	21,388
2026	1,812	1,656	1,094,488	0	0	2,304	21,747
2027	1,834	1,664	1,102,131	0	0	2,358	22,124
2028	1,858	1,671	1,112,052	0	0	2,414	22,522

Notes:
*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

History and 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
2019	1,847	1,596	1,157,247	0	0	1,998	19,402
2020	1,783	1,605	1,110,867	0	0	2,010	19,471
2021	1,811	1,613	1,123,056	0	0	2,021	19,603
2022	1,727	1,622	1,064,651	0	0	2,035	19,666
2023	1,742	1,630	1,068,571	0	0	2,058	19,821
2024	1,744	1,637	1,065,556	0	0	2,085	19,974
2025	1,758	1,645	1,068,969	0	0	2,113	20,138
2026	1,759	1,651	1,065,667	0	0	2,143	20,294
2027	1,773	1,658	1,069,489	0	0	2,174	20,463
2028	1,789	1,665	1,074,706	0	0	2,205	20,645

Notes:

*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 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Base 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**
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	1,031	20,662	9,254	756,254
2019	0	963	20,445	9,218	767,442
2020	0	968	20,602	9,301	781,530
2021	0	979	20,830	9,387	794,860
2022	0	987	20,989	9,483	808,076
2023	0	999	21,246	9,585	821,065
2024	0	1,011	21,504	9,689	833,665
2025	0	1,024	21,775	9,791	845,828
2026	0	1,037	22,041	9,893	857,607
2027	0	1,050	22,323	9,996	869,002
2028	0	1,064	22,622	10,100	880,078

Notes:

December 31, 2018 Status

*Includes sales to Duke Energy Florida (DEF), Wauchula (WAU), St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
Contract ended with 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

History and 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
2019	0	967	20,529	9,237	770,875
2020	0	976	20,774	9,338	788,552
2021	0	992	21,094	9,444	805,624
2022	0	1,004	21,348	9,559	822,731
2023	0	1,020	21,705	9,681	839,757
2024	0	1,037	22,065	9,805	856,533
2025	0	1,056	22,444	9,929	873,013
2026	0	1,073	22,820	10,053	889,238
2027	0	1,092	23,216	10,178	905,207
2028	0	1,112	23,634	10,304	920,975

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.

Schedule 2.3

History and 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
2019	0	959	20,361	9,200	764,008
2020	0	960	20,431	9,264	774,542
2021	0	967	20,570	9,331	784,201
2022	0	970	20,637	9,408	793,637
2023	0	978	20,799	9,491	802,738
2024	0	986	20,960	9,575	811,349
2025	0	994	21,132	9,657	819,432
2026	0	1,002	21,296	9,739	827,043
2027	0	1,010	21,473	9,822	834,194
2028	0	1,020	21,665	9,905	840,950

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.

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
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	4,287	0	4,287	125	0	160	98	106	3,798
2019	4,392	0	4,392	94	0	165	100	107	3,926
2020	4,456	0	4,456	95	0	171	100	110	3,980
2021	4,518	0	4,518	95	0	177	101	113	4,032
2022	4,572	0	4,572	85	0	183	101	116	4,087
2023	4,637	0	4,637	85	0	189	102	119	4,143
2024	4,701	0	4,701	83	0	194	102	123	4,199
2025	4,765	0	4,765	83	0	200	103	126	4,253
2026	4,829	0	4,829	82	0	206	103	129	4,309
2027	4,893	0	4,893	82	0	212	103	132	4,363
2028	4,959	0	4,959	82	0	218	104	135	4,420

Notes:

December 31, 2018 Status
2010, 2016 and 2018 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID, DEF, WAU, STC and FP&L. Contract ended with 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
2019	4,418	0	4,418	94	0	165	100	107	3,952
2020	4,501	0	4,501	95	0	171	100	110	4,025
2021	4,582	0	4,582	95	0	177	101	113	4,096
2022	4,657	0	4,657	85	0	183	101	116	4,172
2023	4,742	0	4,742	85	0	189	102	119	4,248
2024	4,828	0	4,828	83	0	194	102	123	4,326
2025	4,915	0	4,915	83	0	200	103	126	4,403
2026	5,001	0	5,001	82	0	206	103	129	4,481
2027	5,090	0	5,090	82	0	212	103	132	4,560
2028	5,181	0	5,181	82	0	218	104	135	4,642

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)	(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
2019	4,383	0	4,383	94	0	165	100	107	3,917
2020	4,429	0	4,429	95	0	171	100	110	3,953
2021	4,472	0	4,472	95	0	177	101	113	3,986
2022	4,507	0	4,507	85	0	183	101	116	4,022
2023	4,552	0	4,552	85	0	189	102	119	4,058
2024	4,596	0	4,596	83	0	194	102	123	4,094
2025	4,640	0	4,640	83	0	200	103	126	4,128
2026	4,682	0	4,682	82	0	206	103	129	4,162
2027	4,725	0	4,725	82	0	212	103	132	4,195
2028	4,769	0	4,769	82	0	218	104	135	4,230

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
Values shown may be affected due to rounding.

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
2008/09	4,781	152	4,629	181	105	462	75	52	3,754
2009/10	5,140	67	5,073	117	109	470	75	56	4,246
2010/11	4,697	122	4,575	140	88	480	75	58	3,735
2011/12	4,186	120	4,066	103	68	487	83	58	3,267
2012/13	3,780	15	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	4,670	0	4,670	66	0	548	96	77	3,883
2018/19	4,969	0	4,969	89	0	555	96	77	4,151
2019/20	5,024	0	5,024	69	0	563	97	79	4,215
2020/21	5,094	0	5,094	70	0	572	97	80	4,274
2021/22	5,154	0	5,154	60	0	580	98	81	4,336
2022/23	5,227	0	5,227	60	0	588	98	82	4,398
2023/24	5,297	0	5,297	58	0	596	99	83	4,460
2024/25	5,368	0	5,368	58	0	605	100	84	4,521
2025/26	5,437	0	5,437	57	0	613	100	85	4,582
2026/27	5,508	0	5,508	57	0	621	101	86	4,643
2027/28	5,579	0	5,579	57	0	629	102	87	4,703

Notes:

December 31, 2018 Status
2011/2012 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID, DEF, WAU, STC and FP&L. Contract ended with 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
2018/19	4,998	0	4,998	89	0	555	96	77	4,180
2019/20	5,073	0	5,073	69	0	563	97	79	4,264
2020/21	5,164	0	5,164	70	0	572	97	80	4,344
2021/22	5,244	0	5,244	60	0	580	98	81	4,426
2022/23	5,339	0	5,339	60	0	588	98	82	4,510
2023/24	5,432	0	5,432	58	0	596	99	83	4,595
2024/25	5,527	0	5,527	58	0	605	100	84	4,680
2025/26	5,621	0	5,621	57	0	613	100	85	4,766
2026/27	5,717	0	5,717	57	0	621	101	86	4,852
2027/28	5,814	0	5,814	57	0	629	102	87	4,938

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)	(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
2018/19	4,960	0	4,960	89	0	555	96	77	4,142
2019/20	4,997	0	4,997	69	0	563	97	79	4,188
2020/21	5,047	0	5,047	70	0	572	97	80	4,227
2021/22	5,086	0	5,086	60	0	580	98	81	4,268
2022/23	5,139	0	5,139	60	0	588	98	82	4,310
2023/24	5,187	0	5,187	58	0	596	99	83	4,350
2024/25	5,237	0	5,237	58	0	605	100	84	4,390
2025/26	5,283	0	5,283	57	0	613	100	85	4,428
2026/27	5,331	0	5,331	57	0	621	101	86	4,466
2027/28	5,379	0	5,379	57	0	629	102	87	4,503

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
Values shown may be affected due to rounding.

Schedule 3.3

History and Forecast of Annual Net Energy for Load (GWh)
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total*	Residential Conservation**	Comm./Ind. Conservation	Retail	Wholesale ***	Utility Use & Losses	Net Energy for Load	Load **** Factor %
2009	19,449	444	231	18,774	191	978	19,943	53.4
2010	19,923	458	251	19,213	305	1,149	20,667	51.1
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	20,647	618	399	19,631	0	1,031	20,662	58.3
2019	20,497	629	386	19,482	0	963	20,445	53.8
2020	20,668	643	392	19,634	0	968	20,602	53.5
2021	20,906	657	398	19,851	0	979	20,830	53.5
2022	21,077	671	404	20,002	0	987	20,989	53.3
2023	21,342	685	410	20,247	0	999	21,246	53.2
2024	21,608	699	416	20,493	0	1,011	21,504	53.0
2025	21,887	714	422	20,751	0	1,024	21,775	53.1
2026	22,160	728	428	21,004	0	1,037	22,041	53.1
2027	22,449	742	434	21,273	0	1,050	22,323	53.1
2028	22,754	756	440	21,557	0	1,064	22,622	53.0

Notes:

December 31, 2018 Status

*Includes residential and commercial/industrial conservation.

**Includes Energy Planner program.

***Includes sales to RCID, DEF, WAU, STC and FP&L. Contract ended with 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.

Schedule 3.3

Forecast of Annual Net Energy for Load (GWh)
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	**Total***	**Residential Conservation****	**Comm./Ind. Conservation**	**Retail**	**Wholesale**	**Utility Use & Losses**	**Net Energy for Load**	**Load *** Factor %**
2019	20,577	629	386	19,563	0	967	20,529	53.7
2020	20,832	643	392	19,797	0	976	20,774	53.4
2021	21,157	657	398	20,102	0	992	21,094	53.4
2022	21,420	671	404	20,345	0	1,004	21,348	53.2
2023	21,779	685	410	20,684	0	1,020	21,705	53.1
2024	22,143	699	416	21,028	0	1,037	22,065	52.9
2025	22,524	714	422	21,388	0	1,056	22,444	53.0
2026	22,903	728	428	21,747	0	1,073	22,820	52.9
2027	23,300	742	434	22,124	0	1,092	23,216	52.9
2028	23,719	756	440	22,522	0	1,112	23,634	52.8

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.

Schedule 3.3

Forecast of Annual Net Energy for Load (GWh)
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	**Total***	**Residential Conservation****	**Comm./Ind. Conservation**	**Retail**	**Wholesale**	**Utility Use & Losses**	**Net Energy for Load**	**Load *** Factor %**
2019	20,417	629	386	19,402	0	959	20,361	53.7
2020	20,506	643	392	19,471	0	960	20,431	53.4
2021	20,658	657	398	19,603	0	967	20,570	53.4
2022	20,741	671	404	19,666	0	970	20,637	53.2
2023	20,916	685	410	19,821	0	978	20,799	53.1
2024	21,089	699	416	19,974	0	986	20,960	52.9
2025	21,273	714	422	20,138	0	994	21,132	53.0
2026	21,449	728	428	20,294	0	1,002	21,296	53.0
2027	21,639	742	434	20,463	0	1,010	21,473	53.0
2028	21,841	756	440	20,645	0	1,020	21,665	52.9

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.

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)
	2018 Actual		2019 Forecast		2020 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	4,044	1,645	4,337	1,515	4,382	1,513
February	3,120	1,404	3,555	1,331	3,589	1,331
March	2,881	1,430	3,397	1,468	3,425	1,465
April	3,267	1,551	3,557	1,566	3,592	1,566
May	3,607	1,739	3,762	1,812	3,798	1,814
June	3,956	1,973	4,043	1,952	4,102	1,976
July	3,955	2,030	4,070	2,042	4,124	2,068
August	4,037	2,067	4,121	2,063	4,176	2,089
September	4,021	1,997	3,849	1,933	3,900	1,958
October	3,877	1,849	3,623	1,762	3,669	1,784
November	3,272	1,501	3,034	1,443	3,073	1,461
December	2,890	1,476	3,917	1,560	3,971	1,578
TOTAL		20,662		20,445		20,602

Notes:

December 31, 2018 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)
	2018 Actual		2019 Forecast		2020 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	4,044	1,645	4,366	1,521	4,431	1,526
February	3,120	1,404	3,576	1,336	3,626	1,342
March	2,881	1,430	3,412	1,473	3,454	1,476
April	3,267	1,551	3,577	1,572	3,627	1,579
May	3,607	1,739	3,783	1,819	3,836	1,829
June	3,956	1,973	4,067	1,960	4,144	1,993
July	3,955	2,030	4,093	2,050	4,166	2,085
August	4,037	2,067	4,147	2,071	4,221	2,107
September	4,021	1,997	3,871	1,941	3,939	1,975
October	3,877	1,849	3,643	1,769	3,706	1,799
November	3,272	1,501	3,052	1,449	3,104	1,472
December	2,890	1,476	3,928	1,566	3,999	1,590
TOTAL		20,662		20,529		20,774

Notes:
December 31, 2018 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
**Values shown may be affected due to rounding.

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)
	2018 Actual		2019 Forecast		2020 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	4,044	1,645	4,328	1,509	4,355	1,501
February	3,120	1,404	3,546	1,326	3,564	1,321
March	2,881	1,430	3,383	1,462	3,396	1,453
April	3,267	1,551	3,547	1,560	3,566	1,554
May	3,607	1,739	3,751	1,805	3,770	1,800
June	3,956	1,973	4,032	1,943	4,073	1,959
July	3,955	2,030	4,059	2,033	4,096	2,050
August	4,037	2,067	4,112	2,054	4,149	2,071
September	4,021	1,997	3,839	1,925	3,872	1,941
October	3,877	1,849	3,613	1,754	3,643	1,769
November	3,272	1,501	3,027	1,437	3,053	1,449
December	2,890	1,476	3,895	1,554	3,931	1,565
TOTAL		20,662		20,362		20,431

Notes:
December 31, 2018 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)
			Actual	Actual										
	Fuel Requirements	**Unit**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	2,279	1,426	835	1,199	1,399	1,459	233	346	608	554	850	1,325
(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	0	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	0	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	100,445	121,662	124,025	122,338	117,555	115,022	126,596	127,169	125,533	127,827	125,686	118,227
(14)	ST	1000 MCF	8,445	19,777	17,999	14,891	6,486	1,812	435	618	887	841	1,201	1,627
(15)	CC	1000 MCF	91,202	101,372	105,193	106,811	106,701	110,364	125,570	126,026	124,147	126,456	124,086	114,905
(16)	GT	1000 MCF	798	513	833	636	4,368	2,846	591	525	499	530	399	1,695
(17)	Other (Specify)													
(18)	PC	1000 Ton	380	197	0	0	0	0	0	0	0	0	0	161

Notes:
Values shown may be affected due to rounding.
Actual values exclude ignition.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.

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 2017	Actual 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
(1)	Annual Firm Interchange	GWh	122	89	0	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	4,949	2,982	1,725	2,467	2,929	3,039	469	711	1,276	1,163	1,799	2,836
(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	13,685	16,097	16,734	16,618	16,274	16,328	19,156	19,175	18,893	19,279	18,931	17,729
(15)	ST	GWh	744	1,754	1,492	1,184	522	160	25	37	67	61	95	145
(16)	CC	GWh	12,871	14,297	15,168	15,379	15,305	15,877	19,080	19,093	18,783	19,171	18,802	17,434
(17)	GT	GWh	70	45	74	55	447	291	51	45	43	47	34	150
(18)	Renewable	GWh	45	118	1005	1413	1529	1523	1517	1515	1506	1500	1493	1491
(19)	Solar	GWh	45	118	1005	1413	1529	1523	1517	1515	1506	1500	1493	1491
(20)	Other (Specify)													
(21)	PC	GWh	1,064	551	0	0	0	0	0	0	0	0	0	459
(22)	Net Interchange	GWh	244	633	871	(6)	(12)	(11)	(6)	(7)	(10)	(11)	(10)	(3)
(23)	Purchased Energy from Non-Utility Generators	GWh	188	192	110	110	110	110	110	110	110	110	110	110
(24)	Net Energy for Load	GWh	20,298	20,662	20,445	20,602	20,830	20,989	21,246	21,504	21,775	22,041	22,323	22,622

Notes:

Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.

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 2017	Actual 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
(1)	Annual Firm Interchange	%	0.6	0.4	0.0	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	%	24.4	14.4	8.4	12.0	14.1	14.5	2.2	3.3	5.9	5.3	8.1	12.5
(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	%	67.4	77.9	81.8	80.7	78.1	77.8	90.2	89.2	86.8	87.5	84.8	78.4
(15)	ST	%	3.7	8.5	7.3	5.7	2.5	0.8	0.1	0.2	0.3	0.3	0.4	0.6
(16)	CC	%	63.4	69.2	74.2	74.6	73.5	75.6	89.8	88.8	86.3	87.0	84.2	77.1
(17)	GT	%	0.3	0.2	0.4	0.3	2.1	1.4	0.2	0.2	0.2	0.2	0.2	0.7
(18)	Renewable	%	0.2	0.6	4.9	6.9	7.3	7.3	7.1	7.0	6.9	6.8	6.7	6.6
(19)	Solar	%	0.2	0.6	4.9	6.9	7.3	7.3	7.1	7.0	6.9	6.8	6.7	6.6
(20)	Other (Specify)													
(21)	PC	%	5.2	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0
(22)	Net Interchange	%	1.2	3.1	4.3	(0.0)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)
(23)	Purchased Energy from													
(24)	Non-Utility Generators	%	0.9	0.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
(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.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.

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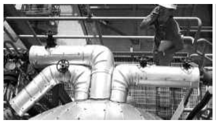
Chapter V



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 added 144.7 MW_{AC} of solar PV generation. In subsequent years, the company will install nearly 480 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 simple cycle 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 2019, TEC plans for 334 MW of cogeneration capacity operating in its service area.

Table IV-I **2019 Cogeneration Capacity Forecast**	**Capacity** **(MW)**
Self-service [1]	263
Firm to Tampa Electric	0
As-available to Tampa Electric	16
Export to other systems	55
Total	334

[1] Capacity and energy that cogenerators produce to serve their own internal load requirements

FIRM INTERCHANGE SALES AND PURCHASES

Currently, TEC has no long-term firm purchase power agreements.

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, Gulfstream Natural Gas System LLC, and Sabal Trail for delivery of natural gas to Big Bend, Bayside, and Polk. As shown in Schedule 6.2, in 2019, coal will fuel 8.4% of the net energy for load, natural gas will fuel 81.8%, and solar will provide 4.9% . The remaining net energy for load is served by firm, non-firm, and non-utility generator purchases. Some of the company's generating units have dual-fuel (i.e., natural gas or oil) capability, which enhances system reliability and provides fuel cost reduction opportunities.

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. 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:

- 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. 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 technology at Big Bend Station. Since Polk Power Station discharges gasification wastewater to the onsite deep injection well rather than to surface water, the limits are not applicable.

Solid Waste

The Coal Combustion Residuals Rule (CCR) became effective on October 19, 2015. The Big Bend Unit #4 Economizer Ash Ponds, the converted Units 1-3 slag fines pond and the South Gypsum Storage Area (SGSA) are covered by this rule. The slag pond will be cleaned out and lined in 2019 to allow for continued storm water storage. Planning is underway to close the Economizer Ponds in 2019-2021 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 by removing and processing the CCRs for beneficial use and restoring the area in 2018-2019. This CCR unit is now regulated by the CCR Rule due to its change in status as a beneficial use storage area. 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)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled * Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2019	5,238	0	0	0	5,238	3,926	1,312	33%	327	984	25%
2020	5,387	0	0	0	5,387	3,980	1,407	35%	391	1,017	26%
2021	5,330	0	0	0	5,330	4,032	1,298	32%	290	1,008	25%
2022	5,330	0	0	0	5,330	4,087	1,243	30%	291	952	23%
2023	5,704	0	0	0	5,704	4,143	1,562	38%	293	1,269	31%
2024	5,704	0	0	0	5,704	4,199	1,506	36%	294	1,212	29%
2025	5,704	0	0	0	5,704	4,253	1,451	34%	295	1,156	27%
2026	5,933	0	0	0	5,933	4,309	1,625	38%	297	1,328	31%
2027	5,933	0	0	0	5,933	4,363	1,570	36%	298	1,272	29%
2028	5,933	0	0	0	5,933	4,420	1,513	34%	299	1,214	27%

Notes:

* Includes 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)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled * Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2018-19	5,536	0	0	0	5,536	4,151	1,385	33%	465	920	22%
2019-20	5,790	0	0	0	5,790	4,215	1,576	37%	707	869	21%
2020-21	5,843	50	0	0	5,893	4,274	1,619	38%	759	859	20%
2021-22	5,753	100	0	0	5,853	4,336	1,517	35%	634	883	20%
2022-23	6,088	0	0	0	6,088	4,398	1,690	38%	634	1,055	24%
2023-24	6,088	0	0	0	6,088	4,460	1,628	37%	634	994	22%
2024-25	6,088	0	0	0	6,088	4,521	1,567	35%	634	932	21%
2025-26	6,332	0	0	0	6,332	4,582	1,751	38%	634	1,116	24%
2026-27	6,332	0	0	0	6,332	4,643	1,689	36%	634	1,055	23%
2027-28	6,332	0	0	0	6,332	4,703	1,629	35%	634	995	21%

Notes:

* Includes capacity unavailable at time of peak.

Values shown may be affected due to rounding.

Schedule 8.1

Planned and Prospective Generating Facility Additions and Changes

(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
Lithia Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	1/19	*	74,500	74.5	74.5	V
Grange Hall Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	1/19	*	61,100	61.1	61.1	V
Bonnie Mine Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	1/19	*	37,500	37.5	37.5	V
Peace Creek Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	3/19	*	55,400	55.4	55.4	V
Lake Hancock Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	4/19	*	49,500	49.5	49.5	V
Little Manatee River Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	1/20	*	74,500	74.5	74.5	P
Wimauma Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	1/20	*	74,800	74.8	74.8	P
Mountain View Solar**	1	Pasco County	PV	SOLAR	NA	NA	NA	-	1/21	*	52,500	52.5	52.5	P
Big Bend	2	Big Bend	ST	BIT	NG	WA/RR	PL	-	04/73	06/21	445,500	(385)	(395)	RT
Big Bend CT 5***	5M	Big Bend	GT	NG	NA	PL	NA	08/19	06/21	*	397,800	360	392	P
Big Bend CT 6***	6M	Big Bend	GT	NG	NA	PL	NA	08/19	06/21	*	397,800	360	392	P
Big Bend ST 1	1M	Big Bend	ST	NG	NA	PL	NA	06/20	01/23	*	445,500	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.

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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[1]	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	Under Construction	
(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[2] (In-Service Year $/kW)	1,494.17	
	Direct Construction Cost ($/kW)	1,460.43	
	AFUDC[3] Amount ($/kW)	33.74	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.17	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [4]	1.12	

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection
[3] Based on the current AFUDC rate of 6.46%
[4] w/o land

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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[1]	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	Under Construction	
(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[2] (In-Service Year $/kW)	1,437.52	
	Direct Construction Cost ($/kW)	1,420.87	
	AFUDC[3] Amount ($/kW)	16.65	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.17	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [4]	1.12	

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection
[3] Based on the current AFUDC rate of 6.46%
[4] w/o land

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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	37.5	MW-ac
	B. Winter	37.5	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[1]	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	Under Construction	
(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[2] (In-Service Year $/kW)	1,464.15	
	Direct Construction Cost ($/kW)	1,442.28	
	AFUDC[3] Amount ($/kW)	21.87	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.17	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [4]	1.12	

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection
[3] Based on the current AFUDC rate of 6.46%
[4] w/o land

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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	55.4	MW-ac
	B. Winter	55.4	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[1]	September 2017	
	B. Commercial In-Service Date	March 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	Under Construction	
(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[2] (In-Service Year $/kW)	1,491.62	
	Direct Construction Cost ($/kW)	1,466.99	
	AFUDC[3] Amount ($/kW)	24.63	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.17	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [4]	1.12	

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection
[3] Based on the current AFUDC rate of 6.46%
[4] w/o land

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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	49.5	MW-ac
	B. Winter	49.5	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[1]	January 2018	
	B. Commercial In-Service Date	April 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	+370 Acres	
(9)	Construction Status	Under Construction	
(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[2] (In-Service Year $/kW)	1,494.23	
	Direct Construction Cost ($/kW)	1,494.23	
	AFUDC[3] Amount ($/kW)	N/A	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.17	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [4]	1.12	

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection
[3] Based on the current AFUDC rate of 6.46%
[4] w/o land

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Little Manatee River 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[1]	December 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	+572 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)	28.6 % (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[2] (In-Service Year $/kW)	1,414.50	
	Direct Construction Cost ($/kW)	1,414.50	
	AFUDC[3] Amount ($/kW)	N/A	
	Escalation ($/kW)	N/A	
	Fixed O&M[4] (In-Service Year $/kW – Yr)	11.63	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [5]	1.17	

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection and excludes land costs
[3] Based on the current AFUDC rate of 6.46%
[4] Fixed O&M cost includes land lease
[5] w/o land

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	74.8	MW-ac
	B. Winter	74.8	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[1]	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)	27.3 % (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[2] (In-Service Year $/kW)	1,490.50	
	Direct Construction Cost ($/kW)	1,458.23	
	AFUDC[3] Amount ($/kW)	32.27	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	5.46	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [4]	1.10	

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection
[3] Based on the current AFUDC rate of 6.46%
[4] w/o land

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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	52.5	MW-ac
	B. Winter	52.5	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[1]	November 2017	
	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	+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 (2021)	27.3 % (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[2] (In-Service Year $/kW)	1,453.34	
	Direct Construction Cost ($/kW)	1,403.61	
	AFUDC[3] Amount ($/kW)	49.73	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	5.58	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [4]	1.10	

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection
[3] Based on the current AFUDC rate of 6.46%
[4] w/o land

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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[1]
	B. Winter	392 MW[1]
(3)	Technology Type	Combustion Turbine[2]
(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	In Progress
(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)	4.4 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	9,557 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	533.17
	Direct Construction Cost ($/kW)	351.04
	AFUDC[3] 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] Net capability will be restricted to 330 MW S / 350 MW W until being placed into combined cycle mode in 2023
[2] Converts to 2x1 Combined Cycle with a HRSG & Big Bend ST 1 in 2023
[3] Based on the current AFUDC rate of 6.46%

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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[1]
	B. Winter	392 MW[1]
(3)	Technology Type	Combustion Turbine[2]
(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	In Progress
(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)	4.4 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	9,557 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	533.17
	Direct Construction Cost ($/kW)	351.04
	AFUDC[3] 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] Net capability will be restricted to 330 MW S / 350 MW W until being placed into combined cycle mode in 2023
[2] Converts to 2x1 Combined Cycle with a HRSG & Big Bend ST 1 in 2023
[3] Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 11 of 13)
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[1]
(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	In Progress
(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)	89.0 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	6,263 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	1,266.28
	Direct Construction Cost ($/kW)	1,037.75
	AFUDC[2] 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] Converts Big Bend CT 5 & 6 and HRSG's to 2x1 Combined Cycle
[2] Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 12 of 13)
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)	0.5 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	11,306 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	607.12
	Direct Construction Cost ($/kW)	532.00
	AFUDC[1] Amount ($/kW)	52.03
	Escalation ($/kW)	23.09
	Fixed O&M (In-Service Year $/kW – Yr)	6.20
	Variable O&M (In-Service Year $/MWh)	12.67
	K-Factor	1.4147

[1] Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 13 of 13)
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)	0.1 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	11,000 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	646.18
	Direct Construction Cost ($/kW)	532.00
	AFUDC[1] Amount ($/kW)	55.37
	Escalation ($/kW)	58.80
	Fixed O&M (In-Service Year $/kW – Yr)	6.60
	Variable O&M (In-Service Year $/MWh)	13.49
	K-Factor	1.5144

[1] Based on the current AFUDC rate of 6.46%

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines
As of December 31, 2018

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
Lithia Solar	Mines - Lithia - Aspen	1	ROW-TEC Owned	1	230 kV	January 2019	$4.0 Million	Lithia Metering Station, Mines & Aspen Substation	None
Little Manatee River Solar	Big Bend - Little Manatee River - Manatee	1	No ROW required	1	230 kV	January 2020	$8.3 Million	Little Manatee River Metering Station, Big Bend & Ruskin 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 request studies pertaining to a Large Generating Facility have been completed and the unit does not require any new transmission lines.

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

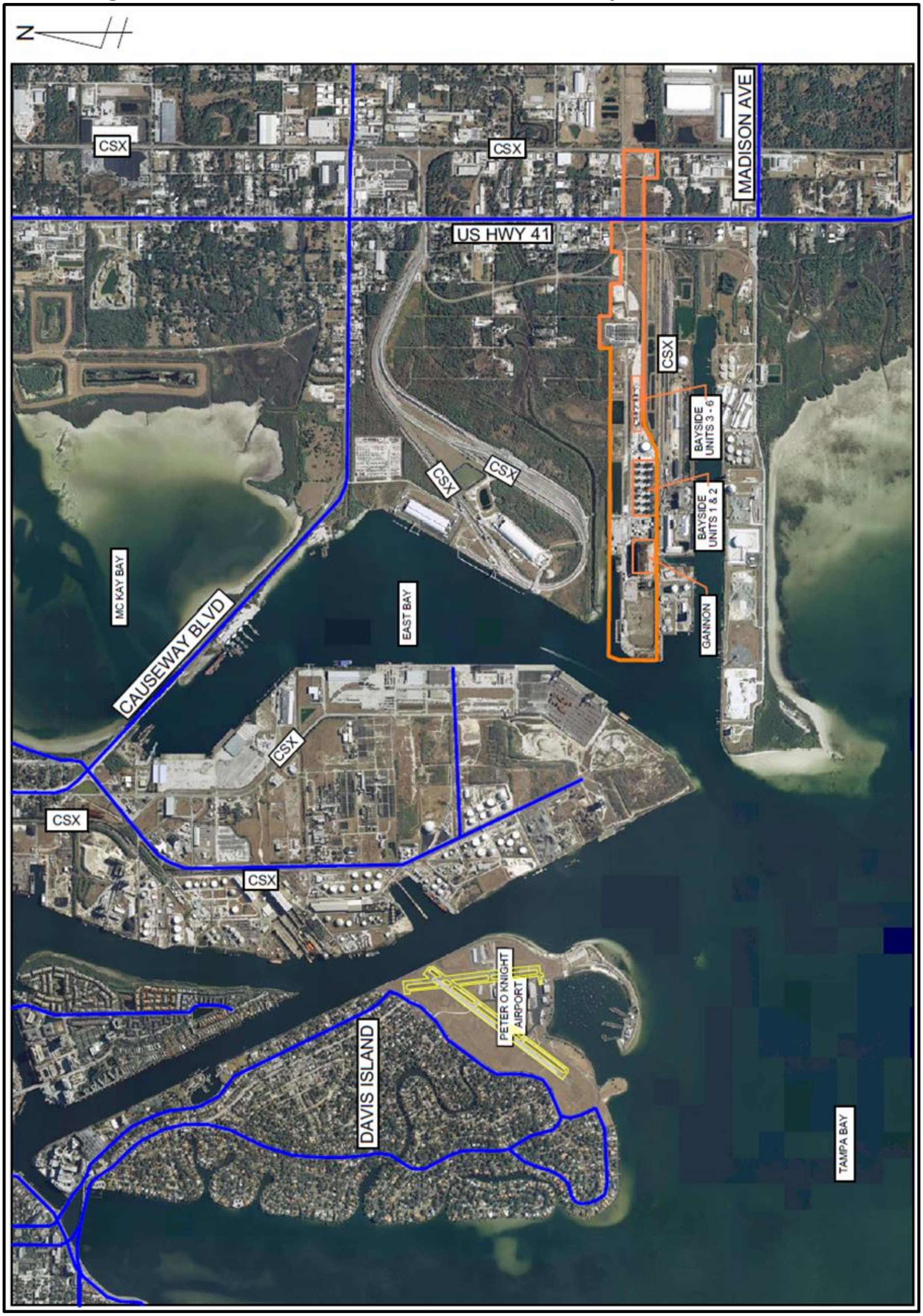

Figure VI-II: Site Location of Polk Power Station

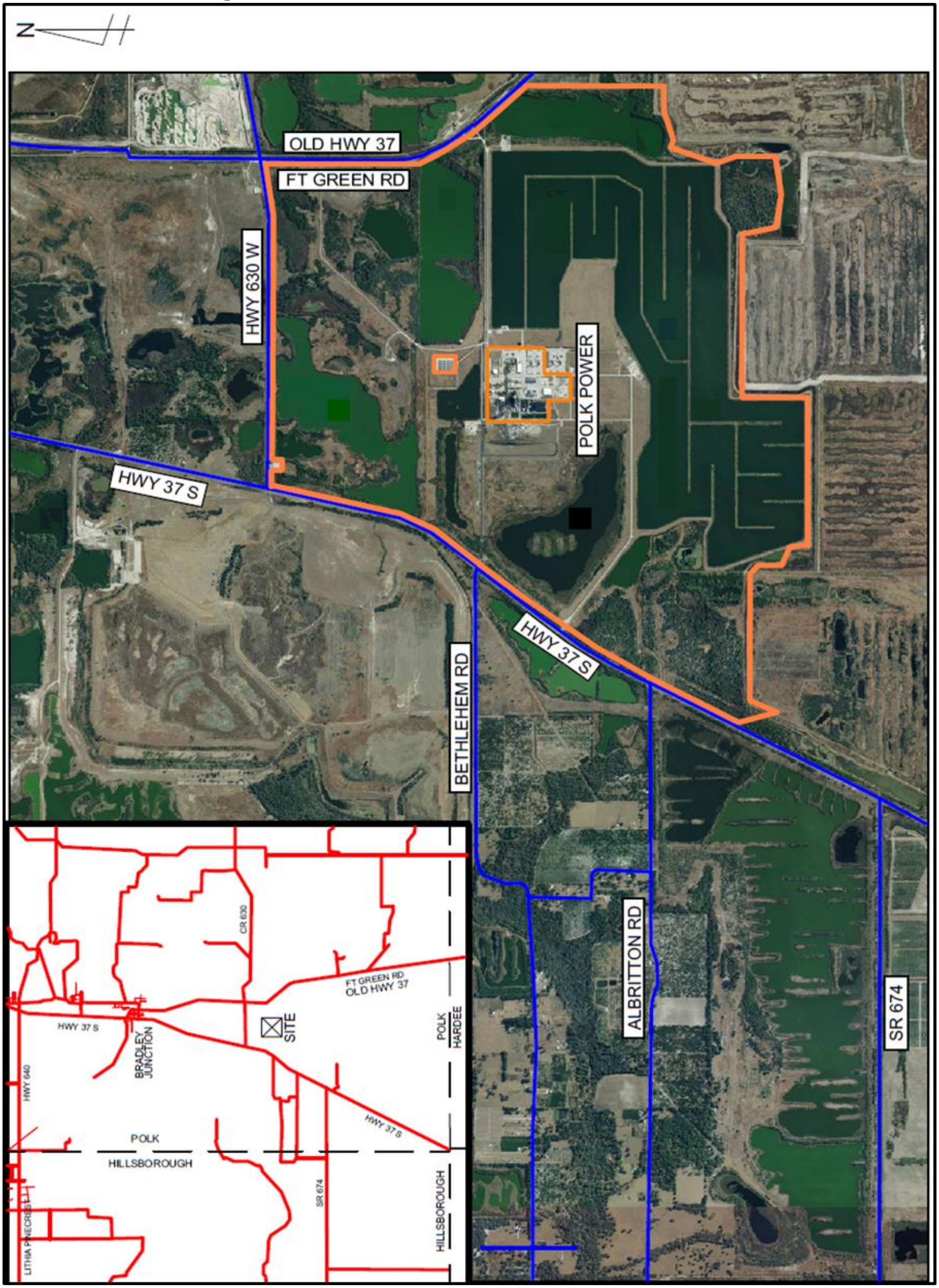

Figure VI-III: Site Location of Big Bend Power Station

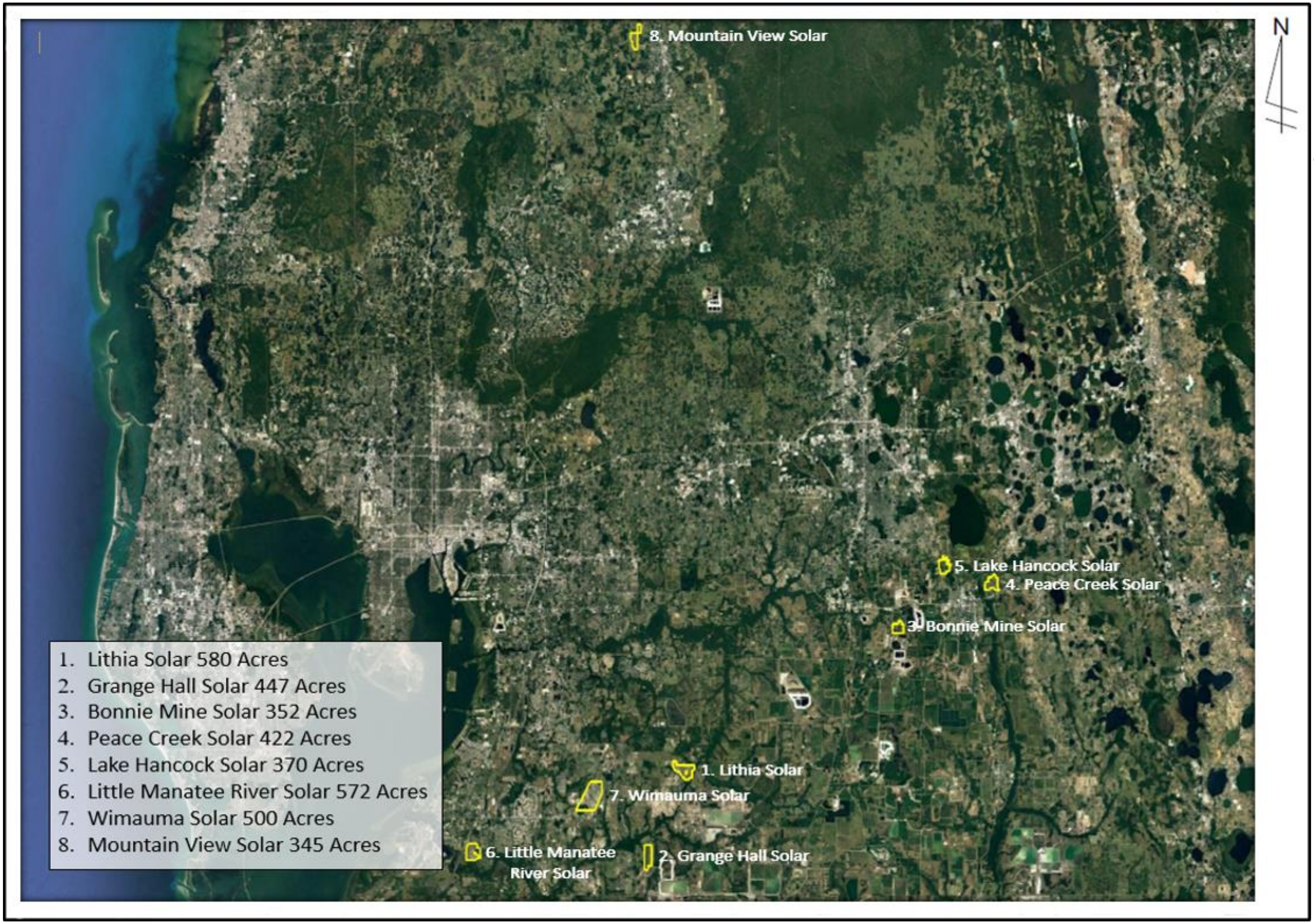

Figure VI-IV: Site Location of Future Solar Power Stations