Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2017 to December 2026

Submitted to: Florida Public Service Commission
April 3, 2017

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GLOSSARY OF TERMS

CODE IDENTIFICATION SHEET

Unit Type:	CC	=	Combined Cycle
	D	=	Diesel
	FS	=	Fossil Steam
	GT	=	Gas Turbine (includes jet engine design)
	HRSG	=	Heat Recovery Steam Generator
	IC	=	Internal Combustion
	IGCC	=	Integrated Gasification Combined Cycle
	PV	=	Photovoltaic
	ST	=	Steam Turbine
Unit Status:	LTRS	=	Long-Term Reserve Stand-By
	OP	=	Operating (In commercial operation)
	OT	=	Other
	P	=	Planned
	T	=	Regulatory Approval Received
	U	=	Under Construction, less than or equal to 50 percent complete
	V	=	Under Construction, more than 50 percent complete
Fuel Type:	BIT	=	Bituminous Coal
	RFO	=	Residual Fuel Oil (Heavy - #6 Oil)
	DFO	=	Distillate Fuel Oil (Light - #2 Oil)
	NG	=	Natural Gas
	PC	=	Petroleum Coke
	WH	=	Waste Heat
	BIO	=	Biomass
	SOLAR	=	Solar Energy
Environmental:	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	SCR	=	Selective Catalytic Reduction
Transportation:	PL	=	Pipeline
	RR	=	Railroad
	TK	=	Truck
	WA	=	Water
Other:	EV	=	Electric Vehicle(s)
	NA	=	Not Applicable

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Executive Summary

Tampa Electric Company's (TEC) 2017 Ten Year Site Plan (TYSP) features plans to enhance electric generating capability as part of our efforts to meet projected incremental resource needs for the 2017 – 2026 time period. The 2017 TYSP provides the Florida Public Service Commission (FPSC) with assurance that TEC will be able to supply cost effective alternatives to ensure the delivery of adequate, safe and reliable power to TEC's customers.

The resource plan presented here is similar to the plan presented by TEC in 2016. The Polk 2 Combined Cycle conversion project is complete, increasing incremental capacity by 463 MW winter and 459 MW summer. In 2015 TEC constructed a 1.6 MW_{AC} photovoltaic (PV) solar array located at Tampa International Airport (TIA) as well as a 1.5 MW_{AC} PV solar array at LEGOLAND®. TEC also completed an 18 MW_{AC} solar PV located at Big Bend Power Station with commercial operation in February 2017. In addition, TEC plans are to add peaking combustion turbines in 2021 and 2024 to continue to adequately meet reserve margin in future years.

TEC is committed to reliably serve the system's demand and energy requirements of its customers. TEC will continue to meet resource requirements with the most economical combination of Demand Side Management (DSM), conservation, renewable energy, purchased power, and generation capacity additions. The resource additions in TEC's 2017 TYSP are projected to be needed based on our current Integrated Resource Planning (IRP) process. The IRP process incorporates an on-going evaluation of demand and supply resources and conservation measures to maintain system reliability. The IRP process is discussed further in Chapter III.

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Chapter I

DESCRIPTION OF EXISTING FACILITIES

Tampa Electric has three (3) generating stations that include fossil steam units, combined cycle units, combustion turbine peaking units, an integrated coal gasification combined cycle unit and multiple solar facilities.

Big Bend Power Station

Big Bend units 1-4 are four (4) pulverized coal-fired steam units equipped with desulfurization scrubbers, electrostatic precipitators, and Selective Catalytic Reduction (SCR) air pollution control systems. Big Bend CT 4 is one (1) aero-derivative combustion turbine that entered into service in 2009 and can be fired with natural gas or distillate oil.

H.L. Culbreath Bayside Power Station

The station operates two (2) natural gas-fired combined cycle units and (4) aero derivative combustion turbines. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) heat recovery steam generators (HRSGs) and one (1) steam turbine. Bayside Unit 2 utilizes four (4) combustion turbines, four (4) HRSGs and one (1) steam turbine. Bayside 3,4,5,6 are four (4) natural gas fired aero-derivative combustion turbines that were placed into service in 2009.

Polk Power Station

The station operates one (1) integrated coal gasification combined cycle unit and one (1) natural gas-fired combined cycle unit. Polk Unit 1 is an integrated gasification combined cycle (IGCC) unit fired with synthetic gas produced from gasified coal and other carbonaceous fuels. This technology integrates state-of-the-art environmental processes to create a clean fuel gas from a variety of feedstock with the efficiency benefits of combined cycle generation equipment. Unit 1 can also be fired with natural gas. On January 16, 2017 Polk 2 Combined Cycle entered commercial operation. Polk 2 CC utilizes four (4) combustion turbines (formally Polk 2-5 simple cycle CT's), four (4) HRSGs and one (1) steam turbine.

Solar

At Tampa International Airport there are 6,175 fixed solar PV panels located atop the south economy parking garage that was placed into service in 2015. The PV solar array located at LEGOLAND® Florida consists of 5,000 solar panels and began operation on December 8, 2016. In addition, the Big Bend Solar Station consisting of 200,000 PV modules located near Big Bend Power Station on nearly 106 acres began operation on February 10, 2017.

Schedule 1

Existing Generating Facilities
As of December 31, 2016

(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	**	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									**1,029,379**	**824**	**952**
	1		IGCC	PC/BIT	NG	WA/TK	PL	*	09/96	**	326,299	220	220
	2		GT	NG	DFO	PL	TK	*	07/00	**	175,770	151	183
	3		GT	NG	DFO	PL	TK	*	05/02	**	175,770	151	183
	4		GT	NG	NA	PL	NA	NA	03/07	**	175,770	151	183
	5		GT	NG	NA	PL	NA	NA	04/07	**	175,770	151	183
TIA		**Hillsborough**											
	1	**Co. 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	**	1,500	1.5	1.5
											TOTAL	**4,339**	**4,731**

Notes:

* Limited by environmental permit

** Undetermined

Figure I-I: Tampa Electric Service Area Map

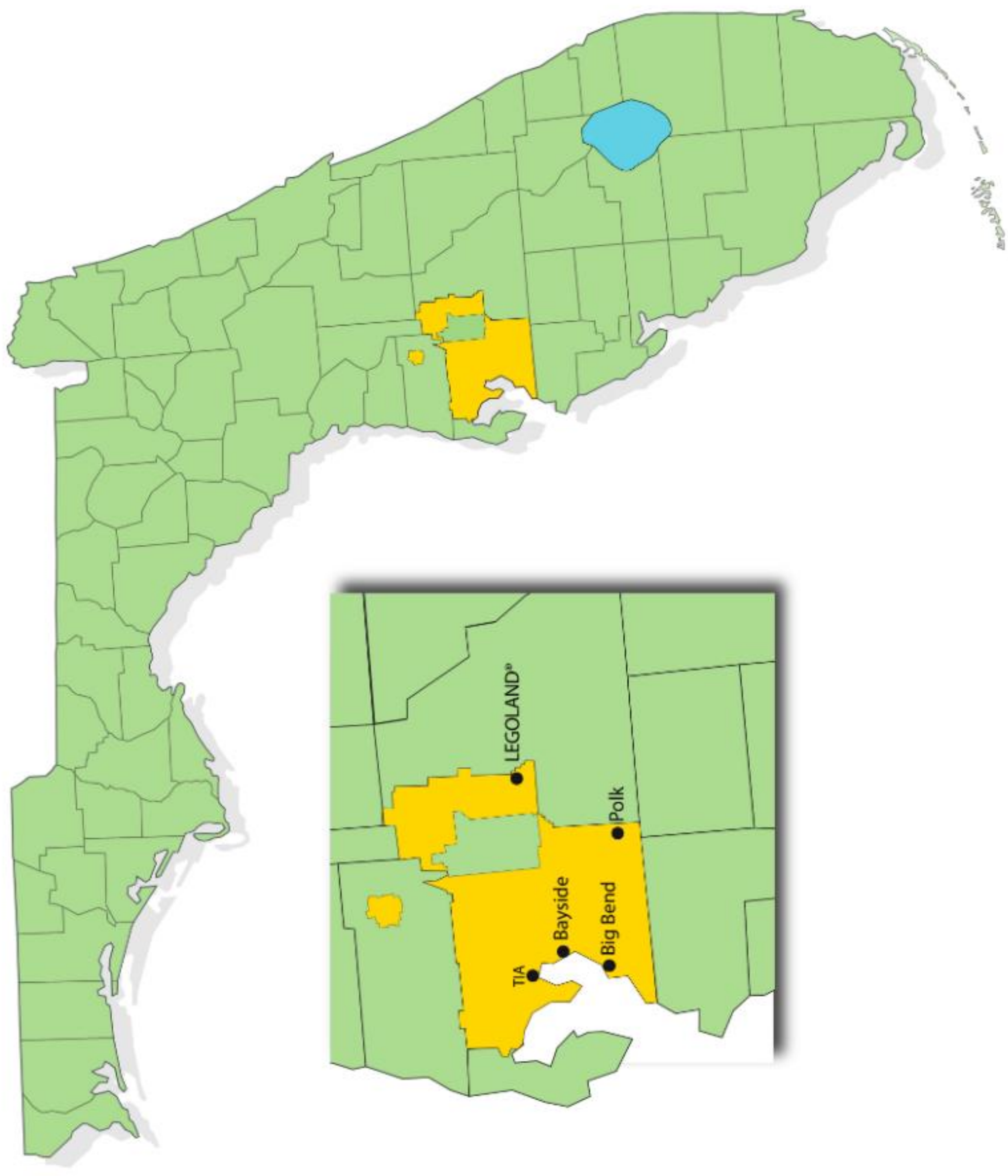

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Figure I-II: Tampa Electric Service Area Transmission System

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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 2017-2026 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the 2017-2026 time period.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2017-2026 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 is forecasted separately and then combined in the final forecast, as well as the effects of photovoltaic (PV) and electric vehicle (EV) related energy. Likewise, the effects of TEC's conservation, load management, and cogeneration programs are incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

1. Economic Analysis

The economic assumptions used in the forecast models are derived from forecasts from Moody's Analytics and the University of Florida's Bureau of Economic and Business Research (BEBR).

See the "Base Case Forecast Assumptions" section of this chapter for an explanation of the most significant economic inputs to the MetrixND models.

2. Customer Multiregression Model

The customer multiregression forecasting model is a seven-equation model. The primary economic drivers in the customer forecast models are population estimates, service area households and employment growth. Below is a description of the models used for the five-customer classes.

1. *Residential Customer Model:* Customer projections are a function of regional population. Since a strong correlation exists between regional population and historical changes in service area customers, regional population estimates were used to forecast the future growth patterns in residential customers.

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

    a. The <u>Commercial Customer Model</u> is a function of population. An increase in the number of households provides the need for additional services, restaurants, and retail establishments. The amount of residential activity also plays a part in the attractiveness of the Tampa Bay area as a place to relocate or start a new business.

    b. Projections of employment in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the <u>Temporary Service Model</u> projects the number of customers as a function of construction employment.

3. *Industrial Customer Model (Non-Phosphate):* Non-phosphate industrial customers include two rate classes that have been modeled individually: General Service and General Service Demand.
    a. The <u>General Service Customer Model</u> is a function of Hillsborough County

commercial employment.

b. The General Service Demand Customer Model is based on Hillsborough County manufacturing employment and the recent growth trend in the sector.

4. *Public Authority Customer Model:* Customer projections are based on the recent growth trend in the sector.

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

3. Energy Multiregression Model

There are a total of seven energy models. All of these models represent average usage per customer (kWh/customer), except for the temporary services model which represents total kWh sales. The average usage models interact with the customer models to arrive at total sales for each class.

The energy models are based on an approach known as Statistically Adjusted Engineering (SAE). SAE entails specifying end-use variables, such as heating, cooling and base use appliance/equipment, and incorporating these variables into regression models. This approach allows the models to capture long-term structural changes that end-use models are known for, while also performing well in the short-term time frame, as do econometric regression models.

1. *Residential Energy Model:* The residential forecast model is made up of three major components: (1) end-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements; (2) changes in the economy such as household income, household size, and the price of electricity; and, (3) weather variables, which serve to allocate the seasonal impacts of weather throughout the year. The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment (XHeat y,m), cooling equipment (XCool y,m), and other equipment (XOther y,m). The XHeat, XCool, and XOther variables are defined as a product of an annual equipment index and a monthly usage multiplier.

   $$\text{Average Usage}_{y,m} = (\text{XHeat}_{y,m} + \text{XCool}_{y,m} + \text{XOther}_{y,m})$$

   Where:

   $$\text{XHeat}_{y,m} = \text{HeatEquipIndex}_{y} \times \text{HeatUse}_{y,m}$$
   $$\text{XCool}_{y,m} = \text{CoolEquipIndex}_{y} \times \text{CoolUse}_{y,m}$$
   $$\text{XOtherUse}_{y,m} = \text{OtherEquipIndex}_{y} \times \text{OtherUse}_{y,m}$$

The annual equipment variables (HeatEquipIndex, CoolEquipIndex, OtherEquipIndex) are defined as a weighted average across equipment types multiplied by equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations and operating efficiencies. The weights are defined by the estimated energy use per household for each equipment type in the base year.

Where:

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

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

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

Next, the monthly usage multiplier or utilization variables (HeatUse, CoolUse, OtherUse) are defined using economic and weather variables. A customer's monthly usage level is impacted by several factors, including weather, household size, income levels, electricity prices and the number of days in the billing cycle. The degree day variables serve to allocate the seasonal impacts of weather throughout the year, while the remaining variables serve to capture changes in the economy.

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

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

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

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

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

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

The SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels and gives estimates of weather sensitivities that vary over time as well as estimate trend adjustments.

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

    a. Commercial Energy Model: The model framework for the commercial sector is the same as the residential model. It also has three major components and utilizes the SAE model framework. The differences lie in the type of end-use equipment and in the economic variables used. The end-use equipment variables are based on commercial appliance/equipment saturation and efficiency assumptions. The economic drivers in the commercial model are commercial productivity measured in terms of dollar output and the price of electricity for the commercial sector. The third component, weather variables, is the same as in the residential model.

b. Temporary Service Energy Model: This model is a subset of the total commercial sector and is a rather small percentage of the total commercial sector. Although small in nature, it is still a component that needs to be included. A simple regression model is used with the primary driver being temporary service customer growth.

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

   a. The General Service Energy Model utilizes the same SAE model framework as the commercial energy model. The weather component is consistent with the residential and commercial models.

   b. The General Service Demand Energy Model is based on manufacturing output, the price of electricity in the industrial sector, cooling degree-days and number of days billed. Unlike the previous models discussed, heating load does not impact this sector.

4. *Public Authority Sector Model:* Within this model, the equipment index is based on the same commercial equipment saturation and efficiency assumptions used in the commercial model. The economic component is based on government sector productivity and the price of electricity in this sector. Weather variables are consistent with the residential and commercial models.

5. *Street & Highway Lighting Sector Model:* The street and highway lighting sector is not impacted by weather; therefore; it is a rather simple model and the SAE modeling approach does not apply. The model is a linear regression model where street and highway lighting energy consumption is a function of the number of billing days in the cycle, and the number of daylight hours in a day for each month.

The seven energy models described above, plus the effects of PV and EV related energy, and an exogenous interruptible and phosphate forecast, are added together to arrive at the total retail energy sales forecast. A line loss factor is applied to the energy sales forecast to produce the retail net energy for load forecast.

In summary, the SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels, gives estimates of weather sensitivity that varies over time, as well as estimates trend adjustments.

4. Peak Demand Multiregression Model

After the retail net energy for load forecast is complete, it is integrated into the peak demand model as an independent variable along with weather variables. The energy variable represents the long-term economic and appliance trend impacts. To stabilize the peak demand data series and improve model accuracy, the volatility of the phosphate load is removed. To further stabilize the data, the peak demand models project on a per customer basis.

The weather variables provide the monthly seasonality to the peaks. The weather variables used are heating and cooling degree-days for both the temperature at the time of the peak and the 24-hour average on the day of the peak and day prior to the peak. By incorporating both temperatures, the model is accounting for the fact that cold/heat buildup contributes to determining the peak day.

The non-phosphate per customer kW forecast is multiplied by the final customer forecast. This result is then aggregated with a phosphate-coincident peak forecast to arrive at the final projected peak demand.

5. Interruptible Demand and Energy Analysis

TEC interruptible customers are relatively few in number, which has allowed the company's Sales and Marketing Department to obtain detailed knowledge of industry developments including:

- Knowledge of expansion and close-out plans;
- Familiarity with historical and projected trends;
- Personal contact with industry personnel;
- Governmental legislation;
- Familiarity with worldwide demand for phosphate products.

This department's familiarity with industry dynamics and their close working relationship with phosphate and other company representatives were used to form the basis for a survey of the interruptible customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast and the commercial/industrial interruptible rate class forecasts are based. Further inputs are provided by individual customer trend analysis and discussions with industry experts.

6. Conservation, Load Management and Cogeneration Programs

Conservation and Load Management demand and energy savings are forecasted for each individual program. The savings are based on a forecast of the annual number of new participants, estimated annual average energy savings per participant and estimated summer and winter average demand savings per participant. The individual forecasts are aggregated and represent the cumulative amount of DSM savings throughout the forecast horizon.

TEC retail demand and energy forecasts are adjusted downward to reflect the incremental demand and energy savings of these DSM programs.

TEC has developed conservation, load management and cogeneration programs to achieve five major objectives:

1. Defer expansion, particularly production plant construction.

2. Reduce marginal fuel cost by managing energy usage during higher fuel cost periods.

3. Provide customers with some ability to control energy usage and decrease energy costs.

4. Pursue the cost-effective accomplishment of the FPSC ten-year demand and energy goals for the residential and commercial/industrial sectors.

5. Achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act (FEECA).

In 2016, 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 successfully completed the phased closure of the company's residential load management program (Prime Time) pursuant to Consummating Order No. PSC-15-0434-CO-EG. 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. 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 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.

7. Residential Heating and Cooling – a rebate program that encourages residential customers to install high-efficiency residential heating and cooling equipment in existing homes.

8. Neighborhood Weatherization – a program that provides for the installation of energy efficient measures for qualified low-income customers.

9. 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.

10. Residential Wall Insulation – a rebate program that encourages existing residential customers to install additional wall insulation in existing homes.

11. Residential Window Replacement – a rebate program that encourages existing residential customers to install window upgrades in existing homes.

12. Commercial Ceiling Insulation – a rebate program that encourages commercial and industrial customers to install additional ceiling insulation in existing commercial structures.

13. Commercial Chiller – a rebate program that encourages commercial and industrial customers to install high efficiency chiller equipment.

14. 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.

15. 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.

16. Cool Roof – a rebate program that encourages commercial and industrial customers to install a cool roof system above conditioned spaces.

17. Commercial Cooling – a rebate program that encourages commercial and industrial customers to install high efficiency direct expansion commercial air conditioning cooling equipment.

18. Demand Response – a turn-key incentive program for commercial and industrial customers to reduce their demand for electricity in response to market signals.

19. Commercial Duct Repair – a rebate program that encourage existing commercial and industrial customers to repair leaky ductwork of central air-conditioning systems in existing commercial and industrial facilities.

20. 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.

21. Industrial Load Management – an incentive program whereby large industrial customers allow for the interruption of their facility or portions of their facility electrical load.

22. 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.

23. 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.

24. Lighting Occupancy Sensors – a rebate program that encourages commercial and industrial customers to install occupancy sensors to control commercial lighting systems.

25. 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.

26. 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.

27. Standby Generator – an incentive program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.

28. Thermal Energy Storage - a rebate program that encourages commercial and industrial customers to install an off-peak air conditioning system.

29. Commercial Wall Insulation – a rebate program that encourages commercial and industrial customers to install wall insulation in existing commercial and industrial structures.

30. Commercial Water Heating – a rebate program that encourages commercial and industrial customers to install high efficiency water heating systems.

31. Conservation Research and Development (R&D) – a program that allows for the exploration of DSM measures that have insufficient data on the cost-effectiveness of the measure and the potential impact to TEC and its ratepayers.

The programs listed above were developed to meet FPSC demand and energy goals established in Docket No. 130201-EI, Order No. PSC-14-0696-FOF-EU, Issued December 16, 2014. The 2016 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

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Variance	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Variance	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % Variance
2015	12.3	2.6	473.1%	10.8	1.1	981.8%	21.2	1.8	1177.8%
2016	7.7	4.1	187.8%	5.1	1.6	318.8%	13.2	3.5	377.1%
2017		5.2			2.2			4.8	
2018		6.5			2.7			6.1	
2019		7.6			3.1			6.9	
2020		7.6			3.3			7.4	
2021		8.0			3.3			7.7	
2022		7.4			3.0			6.9	
2023		6.8			2.9			6.3	
2024		6.1			2.5			5.5	

Commercial/Industrial

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Variance	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Variance	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % 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		1.6			2.7			8.0	
2018		1.7			3.3			9.2	
2019		1.6			3.3			9.9	
2020		1.7			3.5			10.3	
2021		1.9			3.6			10.4	
2022		1.9			3.3			10.2	
2023		1.8			3.5			9.9	
2024		1.7			3.2			9.6	

Combined Total

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Variance	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Variance	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % 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		6.8			4.9			12.8	
2018		8.2			6.0			15.3	
2019		9.2			6.4			16.8	
2020		9.3			6.8			17.7	
2021		9.9			6.9			18.1	
2022		9.3			6.3			17.1	
2023		8.6			6.4			16.2	
2024		7.8			5.7			15.1	

BASE CASE FORECAST ASSUMPTIONS

RETAIL LOAD

Numerous assumptions are inputs to the MetrixND models, of which the more significant ones are listed below.

1. Population and Households
2. Commercial, Industrial and Governmental Employment
3. Commercial, Industrial and Governmental Output
4. Real Household Income
5. Price of Electricity
6. Appliance Efficiency Standards
7. Weather

1. Population and Households

Florida and Hillsborough County population forecasts are the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Moody's Analytics supply population projections for Hillsborough County and Florida comparisons. BEBR's population growth for Hillsborough County was used to project future growth patterns in residential customers for the period of 2017-2026. The average annual population growth rate is expected to be 1.8%.

2. Commercial, Industrial and Governmental Employment

Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. Over the next ten years (2017-2026), employment is assumed to rise at a 1.4% 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 3.4% average annual rate from 2017-2026. 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 2017-2026, 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 2017-2026, retail energy sales are projected to rise at a 1.2% annual rate. The major contributors to growth include the residential and commercial categories, increasing at an annual rate of 1.5% and 0.9%, respectively.

2. Wholesale Energy

For 2017-2018, TEC will sell Reedy Creek Improvement District (RCID) 15 MW of firm wholesale power.

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 2017-2026, TEC's base retail firm peak demand is expected to increase at an average annual rate of 1.4% 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 energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders.

The process incorporates a reliability analysis to determine timing of future needs and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. Initially, a demand and energy forecast, which excludes incremental energy efficiency and conservation programs, is developed. Then, without any incremental energy efficiency and conservation, an interim supply plan based on the system requirements is developed based upon this new demand and energy forecast. This interim supply plan is used to identify the basis for the next potential avoided unit(s). The data from this interim supply plan provides the baseline data that is used to perform a comprehensive cost effectiveness analysis of the energy efficiency and conservation programs.

Once this comprehensive analysis is complete, and the cost-effective energy efficiency and conservation programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the energy efficiency and conservation programs and supply-side resources.

The cost-effectiveness of energy efficiency and demand-response programs is based on the following standard Commission tests: the Rate Impact Measure test (RIM), the Total Resource Cost test (TRC) and the Participants Cost test (PCT). Using the FPSC's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are used in this analysis. All measures that pass the RIM and PCT tests in the energy efficiency and demand response analysis are considered for utility program adoption.

Each adopted measure is quantified into its coincident summer and winter peak kW reduction contribution and its annual kWh savings and is reflected in the demand and energy forecast. TEC evaluates and reports energy efficiency and demand response measures that comports with Rule 25-17.008, F.A.C., the FPSC's prescribed cost-effectiveness methodology.

Generating resources to be considered are determined through an alternative technology screening analysis, which is designed to determine the economic viability of a wide range of generating technologies for the TEC service area.

The technologies that pass the screening are included in a supply-side analysis that examines various supply-side alternatives for meeting future capacity requirements.

TEC uses a computer model developed by ABB, System Optimizer (SO), to evaluate supply-side resources. SO utilizes a mixed integer linear program (MILP) to develop an estimate of the timing and type of supply-side resources for capacity additions that would most economically meet the system demand and energy requirements. The objective function of the MILP is to compare all feasible combinations of generating unit additions, satisfy the specified reliability criteria, and determine the schedule and addition with the lowest total present worth revenue requirements.

Detailed cost analyses for each of the top ranked resource plans are performed using the Planning & Risk (PaR) production cost model, also developed by ABB. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources in our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

The result of the IRP process provides TEC with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Schedule 8.1. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, TEC has converted Polk Units 2-5 to Polk 2 CC, a natural gas combined cycle unit with the addition of a steam turbine that has gone in-service in 2017. The company is also planning the addition of a simple cycle combustion turbine in 2021 and another simple cycle combustion turbine in 2024.

TEC will continue to assess competitive purchase power agreements that may replace or delay the scheduled new units. Such alternatives would be considered if better suited to the overall objective of providing reliable power in the most cost effective manner.

FINANCIAL ASSUMPTIONS

TEC makes numerous financial assumptions as part of the preparation for its TYSP process. These assumptions are based on the current financial status of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code 25-6, an amount for AFUDC is recorded by the company during the construction phase of each capital project that meets the requirements. This rate is approved by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company’s currently approved AFUDC rate.
- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the TYSP.

- The financing cost rates reflect the incremental cost of capital associated with each of the sources of long-term financing.
- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.
- Depreciation represents the annual cost to amortize the total original investment in a plant over its useful life less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the TYSP represents the average expected life for that type of asset.

EXPANSION PLAN ECONOMICS AND FUEL FORECAST

The overall economics and cost-effectiveness of the plan were analyzed using TEC's IRP process. As part of this process, TEC evaluated various planning and operating alternatives against expected operations, with the objective to: meet compliance requirements in the most cost-effective and reliable manner, maximize operational flexibility and minimize total costs.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine the options that were the most feasible overall. Those alternatives that failed to meet the qualitative and quantitative considerations were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in more detailed economic analyses.

TEC forecasts base case natural gas, coal, and oil fuel commodity prices by analyzing current market prices and price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, Wood Mackenzie Energy Group, Coal Daily, Inside FERC, and Platt's Oilgram. For natural gas, coal and oil prices, the company produces both high and low fuel price projections, which represent alternative forecasts to the company's base case outlook.

TAMPA ELECTRIC'S RENEWABLE ENERGY 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.

Through December 2016, TEC's Renewable Energy Program has over 1,749 customers purchasing over 2,600 blocks of renewable energy each month and there have been over 4,000 one-time blocks purchased.

The company's renewable-generation portfolio is a mix of various technologies and renewable fuel sources, including seven smaller, company-owned photovoltaic (PV) arrays. The smaller, community-sited PV arrays are installed at the Museum of Science and Industry, Walker Middle and Middleton High schools, TEC's Manatee Viewing Center, Tampa's Lowry Park Zoo, the Florida Aquarium and LEGOLAND® Florida's Imagination Zone. To further educate the public on the benefits of renewable energy, the installations at these facilities include interactive displays that were built to provide a hands-on experience to engage visitors' interest in solar technology.

TEC continually analyzes renewable energy alternatives with the objective to integrate them into our resource portfolio. The company completed the installation of its first large-scale solar facility at Tampa International Airport in December 2015. The solar PV array, sized at 1.6 MW_{AC}, can produce enough electricity to power up to 250 homes. In December 2016, TEC completed its second large-scale PV system – a 1.5 MW_{AC} array at LEGOLAND® Florida in Winter Haven. This array was constructed on a shade canopy in the park's preferred parking lot and generates enough energy to power more than 200 homes. TEC owns both large-scale solar PV facilities and the electricity they produce goes to the grid to benefit TEC customers. In February 2017, TEC placed in operation the 18 MW_{AC} array which is located at the company's Big Bend Station.

Renewable program participation has reached a level where it is necessary to supplement the company's renewable resources with incremental purchases from a biomass facility in south Florida. Through December 2016, participating customers have utilized over 83 GWh of renewable energy since the program inception.

As market conditions continue to change and technology improves in this sector, renewable alternatives, such as solar, become more cost effective to our customers. Through December 2016, more than 1,100 customers installed PV systems on their homes or businesses, accounting for more than 12 MW of net metered, distributed solar generation interconnected on TEC's grid.

GENERATING UNIT PERFORMANCE ASSUMPTIONS

TEC's generating unit performance assumptions are used to evaluate long-range system operating costs associated with integrated resource plans. Generating units are characterized by several different performance parameters. These parameters include capacity, heat rate, unit derations, planned maintenance days, and unplanned outage rates.

The unit performance projections are based on historical data trends, engineering judgment, time since last planned outage, and recent equipment performance. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on a repetitive pattern.

The forecasted outage schedule is based on unit-specific maintenance needs, material lead-time, labor availability, and the need to supply our customers with power in the most economical manner. Unplanned outage rates are projected based on an average of three years of historical data, future expectations, and any necessary adjustments to account for current unit conditions.

GENERATION RELIABILITY CRITERIA

TEC calculates reserve margin in two ways to measure reliability of the generating system. The company utilizes a minimum 20 percent reserve margin with a minimum contribution of 7 percent supply-side resources. TEC's approach to calculating percent reserves are consistent with the agreement that is outlined in the Commission approved Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, issued December 22, 1999. The calculation of the minimum 20 percent reserve margin employs an industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and 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 CONSTRAINTS AND IMPACTS

Based on a variety of assessments and sensitivity studies of the TEC transmission system, using year 2016 Florida Reliability Coordinating Council (FRCC) database models, no transmission constraints that violate the criteria as described in the Transmission Planning Reliability Criteria section of this document were identified in these studies.

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 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 TEC 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 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 System Planning department ensures 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 BES transmission system elements out of service are analyzed at a variety of load levels. The TEC transmission system is designed such that double contingencies meet the criteria as described in the Transmission Planning Reliability Standards Criteria section of this document

4. *Transmission Construction and Upgrade Plans*

A specific list of the proposed directly associated transmission construction projects corresponding with the proposed generating facilities can be found in Chapter V, Schedule 10. This list represents the latest BES transmission construction related to the generation expansion on Schedule 8 and 9. However, due to the timing of this document in relationship to the company's internal planning schedule, this plan may change in the future. The current transmission construction and upgrade plan for the planning horizon does not require any electric utility system lines to be certified under the Transmission Line Siting Act (403.52-403.536, F.S.).

ENERGY EFFICIENCY, CONSERVATION, AND ENERGY SAVINGS DURABILITY

TEC ensures that DSM programs the company offers are directly monitorable and yield measurable results. The achievements and durability of energy savings from the company's conservation and load management programs is validated by several methods. First, TEC has established a monitoring and evaluation process where historical analysis validates the energy savings. These include:

1. Periodic system load reduction analysis for price responsive load management (Energy Planner), Commercial industrial load management and Commercial demand response to confirm and verify the accuracy of TEC's load reduction estimation formulas.

2. Billing energy usage and demand analysis of participants in certain energy efficiency and conservation programs as compared to control groups.

3. Analysis of DOE2 modeling of various program participants.

4. End-use monitoring and evaluation of projects and programs.

5. Specific metering of loads under control to determine the actual demand and energy savings in commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response.

Second, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Specifically, those programs that promote the installation of energy-efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, wall insulation, window replacements, air distribution system repairs, DX commercial cooling units, chiller replacements, water heating replacements, and ECM motor upgrades) have program standards that require the new equipment to be installed in a permanent manner thus ensuring their durability.

Chapter IV

FORECAST OF ELECTRIC POWER, DEMAND AND ENERGY CONSUMPTION

Tables in Schedules 2 through 4 reflect three different levels of load forecasting: base case, high case, and low case. The expansion plan is developed using the base case load forecast and is reflected on Schedules 5 through 9. This forecast band best represents the current economic conditions and the long-term impacts to TEC's service territory.

Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 3.1: History and Forecast of Summer Peak Demand (Base, High & Low)

Schedule 3.2: History and Forecast of Winter Peak Demand (Base, High & Low)

Schedule 3.3: History and Forecast of Annual Net Energy for Load (Base, High & Low)

Schedule 4: Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month (Base, High & Low)

Schedule 5: History and Forecast of Fuel Requirements

Schedule 6.1: History and Forecast of Net Energy for Load by Fuel Source in GWh

Schedule 6.2: History and Forecast of Net Energy for Load by Fuel Source as a Percent

Schedule 2.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	**Hillsborough County Population**	**Members Per Household**	**GWH**	**Customers***	**Average KWH Consumption Per Customer**	**GWH**	**Customers***	**Average KWH Consumption Per Customer**
2007	1,194,436	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,238,951	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,256,118	2.6	8,395	603,594	13,909	6,185	71,143	86,937
2013	1,276,410	2.6	8,470	613,206	13,812	6,090	71,966	84,619
2014	1,301,887	2.6	8,656	623,846	13,875	6,142	72,647	84,548
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
2016	1,352,797	2.5	9,187	646,221	14,217	6,310	74,313	84,911
2017	1,381,555	2.5	8,951	658,429	13,595	6,334	75,259	84,165
2018	1,409,550	2.5	9,093	670,752	13,556	6,388	76,050	84,000
2019	1,437,372	2.5	9,256	683,068	13,551	6,457	76,763	84,119
2020	1,464,810	2.5	9,377	695,253	13,487	6,506	77,440	84,015
2021	1,491,254	2.5	9,496	707,020	13,431	6,551	78,097	83,886
2022	1,517,131	2.5	9,652	718,565	13,433	6,610	78,744	83,948
2023	1,542,488	2.5	9,784	729,906	13,404	6,676	79,373	84,106
2024	1,567,349	2.5	9,927	741,053	13,396	6,747	79,979	84,362
2025	1,591,735	2.5	10,077	752,012	13,400	6,819	80,563	84,638
2026	1,615,661	2.5	10,230	762,788	13,412	6,892	81,130	84,954

Notes:
December 31, 2016 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2017	1,388,319	2.5	9,009	661,597	13,617	6,348	75,426	84,158
2018	1,423,392	2.5	9,210	677,234	13,599	6,416	76,391	83,986
2019	1,458,605	2.5	9,436	693,010	13,616	6,500	77,288	84,098
2020	1,493,741	2.5	9,621	708,799	13,574	6,564	78,155	83,987
2021	1,528,176	2.5	9,808	724,307	13,541	6,625	79,010	83,852
2022	1,562,334	2.6	10,034	739,729	13,565	6,701	79,862	83,910
2023	1,597,256	2.6	10,238	755,081	13,558	6,784	80,704	84,062
2024	1,631,939	2.6	10,457	770,370	13,574	6,874	81,528	84,315
2025	1,666,401	2.6	10,685	785,601	13,601	6,965	82,337	84,589
2026	1,700,661	2.6	10,919	800,775	13,635	7,058	83,135	84,903

Notes:

*Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.1

Forecast of Energy Consumption and Number of Customers by Customer Class
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
2017	1,374,791	2.5	8,894	655,261	13,574	6,321	75,093	84,172
2018	1,395,775	2.5	8,976	664,302	13,513	6,361	75,710	84,015
2019	1,416,346	2.5	9,079	673,223	13,485	6,415	76,244	84,141
2020	1,436,301	2.4	9,137	681,905	13,400	6,449	76,735	84,043
2021	1,455,049	2.4	9,193	690,069	13,322	6,479	77,202	83,920
2022	1,473,022	2.4	9,283	697,914	13,301	6,522	77,653	83,987
2023	1,490,277	2.4	9,347	705,462	13,250	6,571	78,082	84,149
2024	1,506,845	2.4	9,422	712,726	13,220	6,625	78,483	84,408
2025	1,522,756	2.4	9,501	719,718	13,201	6,678	78,858	84,688
2026	1,538,031	2.4	9,581	726,444	13,190	6,733	79,211	85,006

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
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,494	1,207,299	0	74	1,761	18,564
2012	2,001	1,537	1,302,171	0	75	1,756	18,412
2013	2,027	1,564	1,295,916	0	75	1,756	18,418
2014	1,901	1,572	1,208,831	0	75	1,752	18,526
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	1,945	1,651	1,178,491	0	80	1,803	19,114
2018	1,940	1,668	1,162,826	0	81	1,823	19,325
2019	1,959	1,682	1,164,809	0	81	1,850	19,603
2020	1,974	1,691	1,167,309	0	82	1,869	19,808
2021	1,993	1,701	1,171,695	0	82	1,887	20,010
2022	1,887	1,712	1,101,842	0	82	1,913	20,144
2023	1,910	1,724	1,107,858	0	81	1,941	20,391
2024	1,925	1,735	1,109,344	0	80	1,973	20,651
2025	1,947	1,746	1,115,255	0	78	2,004	20,926
2026	1,970	1,757	1,121,347	0	76	2,038	21,206

Notes:
December 31, 2016 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				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
2017	1,948	1,653	1,178,343	0	80	1,804	19,188
2018	1,945	1,672	1,163,021	0	81	1,825	19,476
2019	1,967	1,687	1,165,696	0	81	1,852	19,836
2020	1,985	1,699	1,168,202	0	82	1,872	20,123
2021	2,006	1,711	1,172,683	0	82	1,891	20,412
2022	1,903	1,724	1,103,911	0	82	1,917	20,638
2023	1,929	1,738	1,110,147	0	81	1,946	20,979
2024	1,948	1,751	1,112,247	0	80	1,979	21,337
2025	1,974	1,764	1,118,774	0	78	2,011	21,713
2026	2,000	1,777	1,125,567	0	76	2,046	22,099

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

Schedule 2.2

Forecast of Energy Consumption and
Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				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
2017	1,943	1,649	1,178,229	0	80	1,802	19,040
2018	1,935	1,664	1,162,572	0	81	1,822	19,174
2019	1,951	1,676	1,164,166	0	81	1,848	19,374
2020	1,964	1,684	1,166,226	0	82	1,866	19,498
2021	1,980	1,692	1,170,154	0	82	1,883	19,617
2022	1,871	1,701	1,099,700	0	82	1,908	19,665
2023	1,891	1,710	1,105,644	0	81	1,936	19,826
2024	1,902	1,719	1,106,649	0	80	1,966	19,995
2025	1,922	1,728	1,112,070	0	78	1,997	20,177
2026	1,941	1,737	1,117,656	0	76	2,030	20,362

Notes:
*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
Base Case

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
2010	305	1,149	20,667	7,827	670,991
2011	93	642	19,298	7,869	675,799
2012	69	839	19,320	7,962	684,236
2013	0	760	19,177	7,999	694,735
2014	0	789	19,315	8,095	706,161
2015	0	1,098	20,105	8,168	718,713
2016	9	930	20,173	8,353	730,503
2017	104	942	20,160	8,371	743,710
2018	104	952	20,381	8,449	756,919
2019	0	966	20,570	8,526	770,039
2020	0	977	20,784	8,604	782,988
2021	0	987	20,996	8,682	795,500
2022	0	994	21,137	8,759	807,780
2023	0	1,006	21,397	8,837	819,840
2024	0	1,019	21,670	8,914	831,681
2025	0	1,033	21,959	8,992	843,314
2026	0	1,047	22,253	9,070	854,744

Notes:

December 31, 2016 Status

*Includes sales to Duke Energy Florida (DEF), Wauchula (WAU), Ft. Meade (FTM), St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
Contract ended with FTM on 12/31/08, DEF on 2/31/11, WAU on 9/31/11, STC on 12/31/2012, FPL on 12/31/12, and RCID on 12/31/10. RCID began again in 2016.
Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.

**Utility Use and Losses include accrued sales.

***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.

****Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.3

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

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
2017	104	946	20,238	8,371	747,047
2018	104	960	20,540	8,449	763,746
2019	0	978	20,813	8,526	780,511
2020	0	992	21,116	8,604	797,257
2021	0	1,007	21,419	8,681	813,709
2022	0	1,018	21,655	8,760	830,075
2023	0	1,035	22,014	8,837	846,360
2024	0	1,053	22,390	8,914	862,563
2025	0	1,071	22,784	8,992	878,694
2026	0	1,091	23,190	9,069	894,756

Notes:

*Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
**Utility Use and Losses include accrued sales.
***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
****Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.3

Forecast of Energy Consumption and Number of Customers by Customer Class
Low 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
2017	104	939	20,083	8,371	740,374
2018	104	945	20,224	8,449	750,125
2019	0	955	20,329	8,526	759,669
2020	0	961	20,459	8,604	768,928
2021	0	968	20,585	8,681	777,644
2022	0	970	20,635	8,760	786,028
2023	0	978	20,804	8,837	794,091
2024	0	987	20,982	8,914	801,842
2025	0	996	21,173	8,992	809,296
2026	0	1,005	21,367	9,069	816,461

Notes:
*Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
**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)	(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
2007	4,428	172	4,256	159	69	80	18	53	3,876
2008	4,276	148	4,128	143	69	84	53	55	3,723
2009	4,316	136	4,180	120	54	90	58	59	3,799
2010	4,171	118	4,053	73	33	97	75	65	3,710
2011	4,130	28	4,102	109	48	103	75	68	3,699
2012	4,089	15	4,073	133	45	111	86	71	3,627
2013	4,072	0	4,072	131	39	122	89	77	3,614
2014	4,270	0	4,270	170	36	132	91	83	3,757
2015	4,245	0	4,245	111	21	143	98	87	3,784
2016	4,403	15	4,388	138	0	150	101	92	3,907
2017	4,310	15	4,294	110	0	154	101	96	3,833
2018	4,372	15	4,357	108	0	159	102	99	3,888
2019	4,426	0	4,426	108	0	164	102	103	3,948
2020	4,486	0	4,486	108	0	170	103	107	3,998
2021	4,546	0	4,546	108	0	175	104	112	4,047
2022	4,598	0	4,598	95	0	181	104	116	4,101
2023	4,662	0	4,662	95	0	186	105	120	4,156
2024	4,728	0	4,728	94	0	191	106	125	4,212
2025	4,796	0	4,796	95	0	197	106	129	4,269
2026	4,862	0	4,862	95	0	202	107	133	4,325

Notes:

December 31, 2016 Status
2010 and 2016 Net Firm Demand is not coincident with system peak
*Includes residential and commercial/industrial conservation.
**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with FTM on 12/31/08, DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract began again with RCID on 01/01/2016.
Forecast includes long-term firm wholesale sales to RCID, 2016 through 2018.
***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
2017	4,327	15	4,311	110	0	154	101	96	3,850
2018	4,406	15	4,391	108	0	159	102	99	3,922
2019	4,479	0	4,479	108	0	164	102	103	4,001
2020	4,557	0	4,557	108	0	170	103	107	4,069
2021	4,637	0	4,637	108	0	175	104	112	4,138
2022	4,710	0	4,710	95	0	181	104	116	4,213
2023	4,795	0	4,795	95	0	186	105	120	4,289
2024	4,882	0	4,882	94	0	191	106	125	4,366
2025	4,973	0	4,973	95	0	197	106	129	4,446
2026	5,063	0	5,063	95	0	202	107	133	4,526

Notes:
*Includes residential and commercial/industrial conservation.
**Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
***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
2017	4,293	15	4,277	110	0	154	101	96	3,816
2018	4,338	15	4,323	108	0	159	102	99	3,854
2019	4,374	0	4,374	108	0	164	102	103	3,896
2020	4,416	0	4,416	108	0	170	103	107	3,928
2021	4,457	0	4,457	108	0	175	104	112	3,958
2022	4,490	0	4,490	95	0	181	104	116	3,993
2023	4,534	0	4,534	95	0	186	105	120	4,028
2024	4,579	0	4,579	94	0	191	106	125	4,063
2025	4,626	0	4,626	95	0	197	106	129	4,099
2026	4,671	0	4,671	95	0	202	107	133	4,134

Notes:
*Includes residential and commercial/industrial conservation.
**Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
***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)	(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**
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,405	152	4,253	120	130	456	53	52	3,443
2008/09	4,696	67	4,629	181	105	462	75	52	3,754
2009/10	5,195	122	5,073	117	109	470	75	56	4,246
2010/11	4,695	120	4,575	140	88	480	75	58	3,735
2011/12	4,081	15	4,066	103	68	487	83	58	3,267
2012/13	3,764	0	3,764	130	65	501	90	61	2,918
2013/14	3,876	0	3,876	61	63	512	97	64	3,079
2014/15	4,195	0	4,195	79	44	521	96	65	3,390
2015/16	4,025	0	4,025	145	13	533	96	67	3,171
2016/17	4,818	15	4,803	94	0	540	98	69	4,002
2017/18	4,882	15	4,867	92	0	547	98	70	4,060
2018/19	4,938	0	4,938	92	0	554	99	71	4,122
2019/20	5,010	0	5,010	92	0	562	100	73	4,183
2020/21	5,073	0	5,073	93	0	570	100	74	4,236
2021/22	5,128	0	5,128	79	0	578	101	76	4,294
2022/23	5,197	0	5,197	80	0	586	101	78	4,352
2023/24	5,265	0	5,265	79	0	594	102	80	4,411
2024/25	5,337	0	5,337	79	0	602	103	81	4,472
2025/26	5,408	0	5,408	79	0	610	103	83	4,532

Notes:

December 31, 2016 Status
2011/2012 Net Firm Demand is not coincident with system peak
*Includes residential and commercial/industrial conservation.
**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with FTM on 12/31/08, DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract began again with RCID on 01/01/2016.
Forecast includes long-term firm wholesale sales to RCID, 2016 through 2018.
***Includes energy planner program
Values shown may be affected due to rounding.

Schedule 3.2

Forecast of Winter 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
2016/17	4,836	15	4,821	94	0	540	98	69	4,020
2017/18	4,918	15	4,903	92	0	547	98	70	4,096
2018/19	4,993	0	4,993	92	0	554	99	71	4,177
2019/20	5,085	0	5,085	92	0	562	100	73	4,258
2020/21	5,168	0	5,168	93	0	570	100	74	4,331
2021/22	5,244	0	5,244	79	0	578	101	76	4,410
2022/23	5,336	0	5,336	80	0	586	101	78	4,491
2023/24	5,427	0	5,427	79	0	594	102	80	4,573
2024/25	5,522	0	5,522	79	0	602	103	81	4,657
2025/26	5,618	0	5,618	79	0	610	103	83	4,742

Notes:
*Includes residential and commercial/industrial conservation.
**Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
***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
2016/17	4,800	15	4,785	94	0	540	98	69	3,984
2017/18	4,846	15	4,831	92	0	547	98	70	4,024
2018/19	4,884	0	4,884	92	0	554	99	71	4,068
2019/20	4,936	0	4,936	92	0	562	100	73	4,109
2020/21	4,980	0	4,980	93	0	570	100	74	4,143
2021/22	5,014	0	5,014	79	0	578	101	76	4,180
2022/23	5,063	0	5,063	80	0	586	101	78	4,218
2023/24	5,110	0	5,110	79	0	594	102	80	4,256
2024/25	5,159	0	5,159	79	0	602	103	81	4,294
2025/26	5,208	0	5,208	79	0	610	103	83	4,332

Notes:
*Includes residential and commercial/industrial conservation.
**Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
***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 %
2007	20,153	421	200	19,533	829	916	21,278	56.6
2008	19,632	431	212	18,990	752	909	20,650	56.8
2009	19,449	444	231	18,774	191	978	19,943	54.4
2010	19,923	458	251	19,213	305	1,149	20,667	50.5
2011	19,296	474	259	18,564	93	642	19,298	53.0
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	20,053	597	342	19,114	104	942	20,160	54.7
2018	20,285	609	352	19,325	104	952	20,381	54.6
2019	20,586	621	362	19,603	0	966	20,570	54.4
2020	20,815	634	374	19,808	0	977	20,784	54.1
2021	21,043	646	387	20,010	0	987	20,996	54.1
2022	21,203	659	400	20,144	0	994	21,137	53.9
2023	21,476	672	413	20,391	0	1,006	21,397	53.9
2024	21,761	684	425	20,651	0	1,019	21,670	53.7
2025	22,061	697	438	20,926	0	1,033	21,959	53.9
2026	22,367	709	451	21,206	0	1,047	22,253	53.9

Notes:

December 31, 2016 Status

*Includes residential and commercial/industrial conservation.

**Includes Energy Planner program

**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with FTM on 12/31/08, DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract began again with RCID on 01/01/2016.
Forecast includes long-term firm wholesale sales to RCID, 2016 through 2018.

****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 %
2017	20,127	597	342	19,188	104	946	20,238	54.7
2018	20,436	609	352	19,476	104	960	20,540	54.5
2019	20,819	621	362	19,836	0	978	20,813	54.4
2020	21,131	634	374	20,123	0	992	21,116	54.0
2021	21,445	646	387	20,412	0	1,007	21,419	54.0
2022	21,696	659	400	20,638	0	1,018	21,655	53.9
2023	22,063	672	413	20,979	0	1,035	22,014	53.8
2024	22,446	684	425	21,337	0	1,053	22,390	53.6
2025	22,848	697	438	21,713	0	1,071	22,784	53.7
2026	23,259	709	451	22,099	0	1,091	23,190	53.8

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
****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 %
2017	19,959	597	342	19,040	104	939	20,083	54.7
2018	20,114	609	352	19,174	104	945	20,224	54.6
2019	20,334	621	362	19,374	0	955	20,329	54.5
2020	20,481	634	374	19,498	0	961	20,459	54.2
2021	20,625	646	387	19,617	0	968	20,585	54.2
2022	20,699	659	400	19,665	0	970	20,635	54.0
2023	20,884	672	413	19,826	0	978	20,804	54.0
2024	21,079	684	425	19,995	0	987	20,982	53.8
2025	21,286	697	438	20,177	0	996	21,173	54.0
2026	21,497	709	451	20,362	0	1,005	21,367	54.0

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Forecast includes long-term firm wholesale sales to RCID, 2017 through 2018.
****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)
	2016 Actual		2017 Forecast		2018 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,339	1,472	4,209	1,488	4,265	1,500
February	3,105	1,370	3,479	1,322	3,522	1,333
March	3,169	1,476	3,323	1,460	3,363	1,473
April	3,619	1,534	3,483	1,556	3,526	1,571
May	3,633	1,780	3,695	1,800	3,742	1,820
June	3,971	1,950	3,978	1,957	4,028	1,980
July	4,146	2,089	4,002	2,011	4,054	2,036
August	4,116	2,035	4,059	2,057	4,113	2,083
September	3,822	1,925	3,781	1,903	3,830	1,927
October	3,557	1,686	3,581	1,704	3,629	1,725
November	2,891	1,382	3,001	1,406	3,040	1,423
December	2,996	1,474	3,762	1,495	3,814	1,512
TOTAL		20,173		20,160		20,381

December 31, 2016 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)
	2016 Actual		2017 Forecast		2018 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,339	1,472	4,227	1,494	4,301	1,511
February	3,105	1,370	3,494	1,327	3,551	1,343
March	3,169	1,476	3,336	1,466	3,391	1,484
April	3,619	1,534	3,497	1,561	3,555	1,583
May	3,633	1,780	3,710	1,807	3,773	1,834
June	3,971	1,950	3,994	1,965	4,062	1,995
July	4,146	2,089	4,018	2,019	4,087	2,053
August	4,116	2,035	4,076	2,065	4,147	2,099
September	3,822	1,925	3,796	1,910	3,862	1,942
October	3,557	1,686	3,596	1,711	3,658	1,739
November	2,891	1,382	3,013	1,412	3,064	1,434
December	2,996	1,474	3,777	1,500	3,845	1,522
TOTAL		20,173		20,238		20,540

December 31, 2016 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)
	2016 Actual		2017 Forecast		2018 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,339	1,472	4,191	1,483	4,229	1,488
February	3,105	1,370	3,465	1,318	3,493	1,323
March	3,169	1,476	3,309	1,455	3,336	1,462
April	3,619	1,534	3,468	1,550	3,497	1,559
May	3,633	1,780	3,680	1,793	3,711	1,806
June	3,971	1,950	3,962	1,950	3,995	1,964
July	4,146	2,089	3,985	2,002	4,021	2,020
August	4,116	2,035	4,042	2,049	4,079	2,066
September	3,822	1,925	3,765	1,895	3,799	1,911
October	3,557	1,686	3,567	1,697	3,599	1,712
November	2,891	1,382	2,990	1,401	3,017	1,412
December	2,996	1,474	3,747	1,489	3,783	1,500
TOTAL		20,173		20,084		20,224

December 31, 2016 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	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	3,682	3,005	3,761	3,635	3,781	3,604	3,222	3,101	3,138	3,244	3,283	3,283
(3)	Residual	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)	CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)	GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)	D	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	1000 BBL	1	1	0	0	0	0	0	0	0	0	0	0
(9)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)	CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)	GT	1000 BBL	1	1	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	74,847	77,896	71,973	77,042	75,535	79,583	88,875	91,917	92,301	94,204	94,997	98,270
(14)	ST	1000 MCF	0	8,736	4,650	4,519	4,597	4,458	4,037	3,899	3,921	4,086	4,110	4,131
(15)	CC	1000 MCF	66,304	59,525	64,508	67,413	67,422	70,868	78,381	79,565	82,281	81,176	82,087	83,458
(16)	GT	1000 MCF	8,543	9,635	2,815	5,110	3,516	4,257	6,457	8,453	6,099	8,942	8,800	10,681
(17)	Other (Specify)													
(18)	PC	1000 Ton	325	393	422	350	435	433	395	432	432	407	432	432

Notes:
Values shown may be affected due to rounding.
All values exclude ignition.

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 2015	Actual 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	Annual Firm Interchange	GWh	438	193	143	166	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	8,208	7,667	8,389	8,105	8,431	8,042	7,180	6,871	6,968	7,209	7,305	7,299
(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	9,919	10,129	10,066	10,660	10,536	11,086	12,335	12,649	12,857	12,987	13,092	13,425
(15)	ST	GWh	0	899	425	413	427	408	363	345	351	364	367	368
(16)	CC	GWh	9,161	8,381	9,392	9,792	9,800	10,303	11,395	11,546	11,961	11,818	11,932	12,093
(17)	GT	GWh	758	849	249	455	309	375	577	758	545	805	793	964
(18)	Renewable	GWh	0	3	34	47	47	46	46	46	45	45	45	44
(19)	Solar	GWh	0	3	34	47	47	46	46	46	45	45	45	44
(20)	Other (Specify)													
(21)	PC	GWh	911	1,100	1,193	988	1,231	1,224	1,116	1,220	1,220	1,148	1,220	1,220
(22)	Net Interchange	GWh	289	842	195	275	235	296	229	261	217	191	206	175
(23)	Purchased Energy from Non-Utility Generators	GWh	341	237	140	140	90	90	90	90	90	90	90	90
(24)	Net Energy for Load	GWh	20,105	20,173	20,160	20,381	20,570	20,784	20,996	21,137	21,397	21,670	21,959	22,253

Notes:
Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.

Schedule 6.2

History and Forecast of Net Energy for Load by Fuel Source
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources	Unit	Actual 2015	Actual 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	Annual Firm Interchange	%	2.2	1.0	0.7	0.8	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	%	40.8	38.0	41.6	39.8	41.0	38.7	34.2	32.5	32.6	33.3	33.3	32.8
(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	%	49.3	50.2	49.9	52.3	51.2	53.3	58.7	59.8	60.1	59.9	59.6	60.3
(15)	ST	%	0.0	4.5	2.1	2.0	2.1	2.0	1.7	1.6	1.6	1.7	1.7	1.7
(16)	CC	%	45.6	41.5	46.6	48.0	47.6	49.6	54.3	54.6	55.9	54.5	54.3	54.3
(17)	GT	%	3.8	4.2	1.2	2.2	1.5	1.8	2.7	3.6	2.5	3.7	3.6	4.3
(18)	Renewable	%	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(19)	Solar	%	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(20)	Other (Specify)													
(21)	PC	%	4.5	5.5	5.9	4.8	6.0	5.9	5.3	5.8	5.7	5.3	5.6	5.5
(22)	Net Interchange	%	1.4	4.2	1.0	1.3	1.1	1.4	1.1	1.2	1.0	0.9	0.9	0.8
(23)	Purchased Energy from													
(24)	Non-Utility Generators	%	1.7	1.2	0.7	0.7	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
(25)	Net Energy for Load	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Notes:
Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.

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Chapter V

FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility additions and changes 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 meet the expected system demand and energy requirements over the next ten years, both peaking and intermediate resources are needed. In 2017, TEC will be utilizing the newly converted Polk Power Station's simple cycle combustion turbines (Polk Units 2-5) to Polk 2 CC, a natural gas combined cycle (NGCC) unit for its intermediate load needs. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 9. TEC also completed an 18 MW_{AC} PV solar array located at Big Bend Station in early 2017. Beyond 2017, the company foresees the future needs being additional peaking capacity from two combustion turbines, one in 2021 and additional combustion turbine in 2024, which it proposes to meet by additions and/or future purchase power agreements.

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 2017, TEC plans for 369 MW of cogeneration capacity operating in its service area.

Table IV-I 2017 Cogeneration Capacity Forecast	Capacity (MW)
Self-service [1]	306
Firm to Tampa Electric	0
As-available to Tampa Electric	7
Export to other systems	56
Total	369

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

FIRM INTERCHANGE SALES AND PURCHASES

Currently, TEC has long-term firm sale and purchase power agreements. Below are the contracts for capacity and energy:

- 15 MW sale to Reedy Creek Improvement District (RCID) through December 31, 2018.
- 121 MW purchase from Quantum Pasco Power through December 2018
- 250 MW purchase from Duke Energy through February 28, 2017

FUEL REQUIREMENTS

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2. TEC currently uses a generation portfolio consisting mainly of solid fuels and natural gas for its energy requirements. TEC has firm transportation contracts with the Florida Gas Transmission Company and Gulfstream Natural Gas System LLC for delivery of natural gas to Big Bend, Bayside, and Polk. As shown in Schedule 6.2, in 2017 coal and petcoke will fuel 47.4% of the net energy for load and natural gas will fuel 50.1%. The remaining net energy for load is served by firm, non-firm, and non-utility generator purchases. Some of the company's generating units also have dual-fuel (i.e., natural gas or oil) capability, which enhances system reliability. However, TEC's capacity is roughly evenly split between solid fuels and natural gas.

ENVIRONMENTAL CONSIDERATIONS

Air Quality

TEC continually strives to reduce emissions from its generating facilities. Since 1998, TEC has reduced annual sulfur dioxides (SO_2) by 94 percent, nitrogen oxides (NO_x) by 91 percent, particulate matter (PM) by 87 percent and mercury emissions by 90 percent. These reductions were the result of a December 1999 agreement between the Florida Department of Environmental Protection and TEC. In February 2000, TEC reached a similar agreement with the U.S. Environmental Protection Agency in a Consent Decree. TEC fulfilled all commitments of the agreement and the motion to terminate the Consent Decree was granted on November 22, 2013. The order granting the motion to terminate the Consent Final Judgment was granted on May 6, 2015. TEC's major activities to increase pollution control and decrease emissions include:

- Improvement of the Big Bend electrostatic precipitators

- The installation of natural gas-fired igniters at Big Bend Station and ongoing engineering testing through 2017 will continue to provide opportunities to augment coal-fired operation and further reduce emissions during startup and normal operation.

- Polk Power Station combined-cycle project will improve system reliability and further reduce emissions system-wide.

TEC will continue to reduce emissions through project enhancements and best operation & maintenance work practices. However, the company recognizes that environmental regulations continue to change. As these regulations evolve, they will impact both cost and operations.

Water Quality

The final 316(b) rule became effective in October 2014 and seeks to reduce impingement and entrainment at cooling water intakes. This rule affects both Big Bend and Bayside Power Stations, since both withdraw cooling water from waters of the U.S. The full impact of the new regulations will be determined by the results of the study elements performed to comply with the rule as well as the actual requirements of the state regulatory agencies.

FDEP's numeric nutrient regulations are effective and may potentially impact the discharge from the Polk Power Station cooling water reservoir in the future. The established nitrogen allocations by Tampa Bay Nitrogen Management Consortium for both Bayside and Big Bend Power Stations are expected to meet the numeric nutrient criteria in Tampa Bay.

The final Effluent Limitations Guidelines (ELG) were published on November 3, 2015. The ELGs establish limits for wastewater discharges from flue gas desulfurization (FGD) processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals, gasification processes, and flue gas mercury controls. New limits will require new treatment technology at Big Bend Station and potentially require new treatment at Polk Power Station.

Solid Waste

The Coal Combustion Residuals Rule (CCR) became effective on October 19, 2015. The Big Bend Unit #4 Economizer Ash Ponds and the converted Units 1-3 slag fines pond are covered by this rule. The slag pond will be cleaned out and lined in 2017 to allow for continued storm water storage. Planning is underway to cap and close the Economizer Ponds in-place by 2019 and to perform post-closure care and monitoring for 30 years thereafter. 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)
	Firm 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
2017	4,804	121	15	0	4,910	3,833	1,077	28%	0	1,077	28%
2018	4,804	121	15	0	4,910	3,888	1,022	26%	0	1,022	26%
2019	4,804	0	0	0	4,804	3,948	857	22%	0	857	22%
2020	4,804	0	0	0	4,804	3,998	806	20%	0	806	20%
2021	5,008	0	0	0	5,008	4,047	961	24%	0	961	24%
2022	5,008	0	0	0	5,008	4,101	907	22%	0	907	22%
2023	5,008	0	0	0	5,008	4,156	852	21%	0	852	21%
2024	5,212	0	0	0	5,212	4,212	1,000	24%	0	1,000	24%
2025	5,212	0	0	0	5,212	4,269	943	22%	0	943	22%
2026	5,212	0	0	0	5,212	4,325	887	21%	0	887	21%

Notes:

* Includes purchase power agreement (PPA) Quantum Pasco Power of 121 MW through 2018.

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)
	Firm 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
2016-17	5,191	371	15	0	5,547	4,002	1,545	39%	0	1,545	39%
2017-18	5,191	121	15	0	5,297	4,060	1,237	30%	0	1,237	30%
2018-19	5,191	0	0	0	5,191	4,122	1,069	26%	0	1,069	26%
2019-20	5,191	0	0	0	5,191	4,183	1,008	24%	0	1,008	24%
2020-21	5,191	0	0	0	5,191	4,236	955	23%	0	955	23%
2021-22	5,411	0	0	0	5,411	4,294	1,117	26%	0	1,117	26%
2022-23	5,411	0	0	0	5,411	4,352	1,059	24%	0	1,059	24%
2023-24	5,411	0	0	0	5,411	4,411	1,000	23%	0	1,000	23%
2024-25	5,631	0	0	0	5,631	4,472	1,159	26%	0	1,159	26%
2025-26	5,631	0	0	0	5,631	4,532	1,099	24%	0	1,099	24%

Notes:

* Includes purchase power agreements (PPA) with Duke Energy Florida LLC of 250 MW through Feb 2017, and Quantum Pasco Power of 121 MW through 2018.

Schedule 8.1

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.						Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Summer MW	Winter MW	Status
Polk 2 CC	2	Polk	CC	NG	DFO	PL	TK	01/14	01/17	*	*	1,063	1,195	OP**
Big Bend Solar	1	Big Bend	PV	SOLAR	NA	NA	NA	5/16	02/17	*	*	18	18	OP**
Future CT 1	1	*	GT	NG	NA	PL	NA	05/19	05/21	*	*	204	220	P
Future CT 2	2	*	GT	NG	NA	PL	NA	05/22	05/24	*	*	204	220	P

Notes:

* Undetermined

** Polk 2 Combined Cycle began commercial operation 01/16/17 and Big Bend Solar began commercial operation 02/10/17.

Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future CT 1
(2)	Net Capability	
	A. Summer	204 MW
	B. Winter	220 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	Mar 2019
	B. Commercial In-Service Date	May 2021
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.04
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.94
	Resulting Capacity Factor (2021)	11.2 %
	Average Net Operating Heat Rate (ANOHR) [1]	10,944 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	854.71
	Direct Construction Cost ($/kW) [1]	629.39
	AFUDC* Amount ($/kW) [1]	87.71
	Escalation ($/kW) [1]	137.62
	Fixed O&M ($/kW – Yr) [1]	13.49
	Variable O&M ($/MWh) [1]	2.17
	K-Factor	1.4181

[1] Based on In-Service Year.

* Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 2 of 2)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future CT 2
(2)	Net Capability	
	A. Summer	204 MW
	B. Winter	220 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	Mar 2022
	B. Commercial In-Service Date	May 2024
(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)	9.6 %
	Average Net Operating Heat Rate (ANOHR) [1]	10,920 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	920.43
	Direct Construction Cost ($/kW) [1]	622.65
	AFUDC* Amount ($/kW) [1]	94.45
	Escalation ($/kW) [1]	203.34
	Fixed O&M ($/kW – Yr) [1]	14.48
	Variable O&M ($/MWh) [1]	2.33
	K-Factor	1.4181

[1] Based on In-Service Year.

* Based on the current AFUDC rate of 6.46%

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

Units	Point of Origin and Termination	Number of Circuits	Right-of-Way (ROW)	Circuit Length **	Voltage	Anticipated In-Service Date	Anticipated Capital Investment ***	Substations	Participation with Other Utilities
Future CT 1	Unsited *	-	-	-	-	May 2021	-	-	-
Future CT 2	Unsited *	-	-	-	-	May 2024	-	-	-

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.

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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 facilities are currently permitted as existing power plant sites. Additional land use requirements and/or alternative site locations are not currently under consideration.

Figure VI-I: Site Location of H.L. Culbreath Bayside Power Station

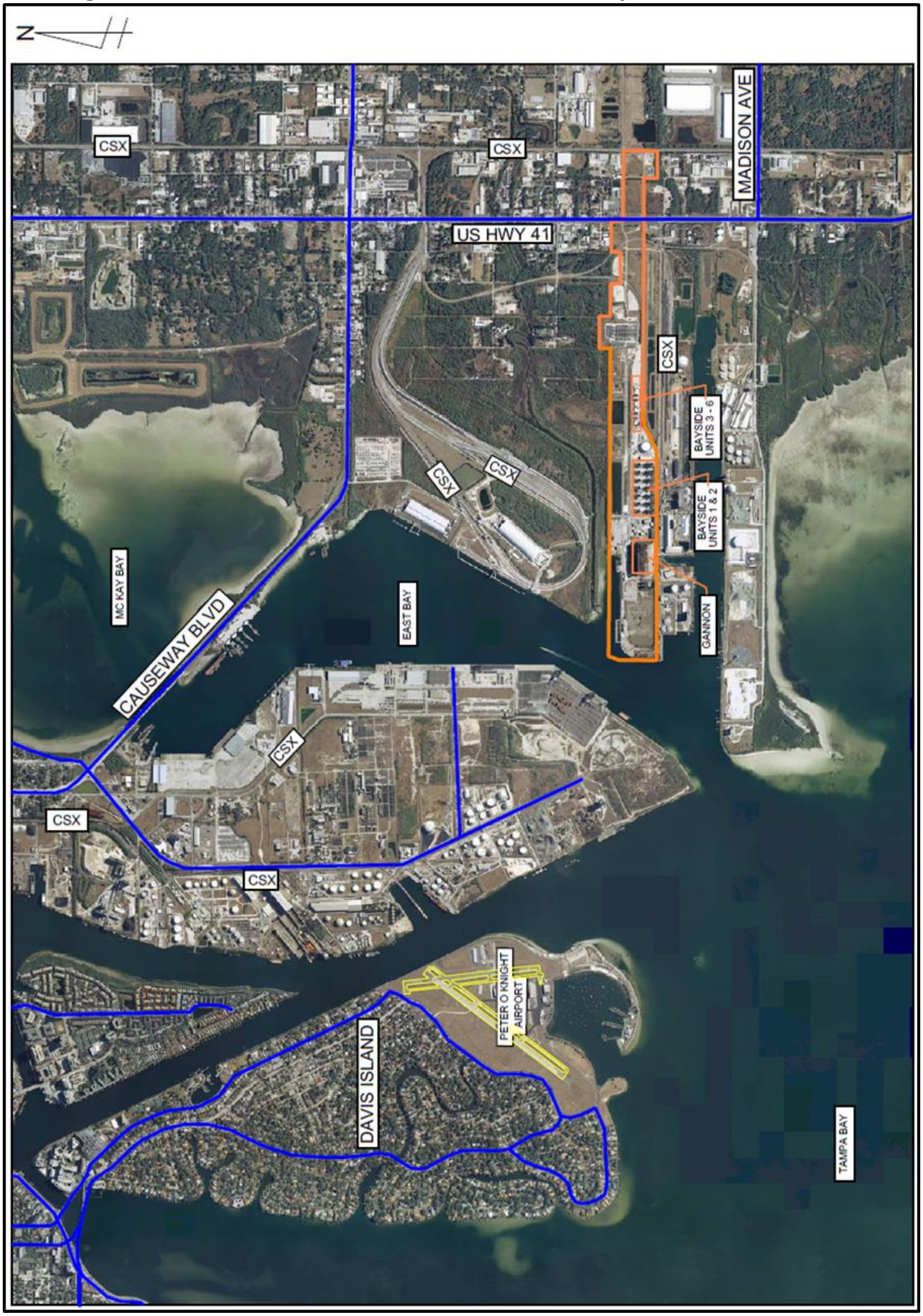

Figure VI-II: Site Location of Polk Power Station

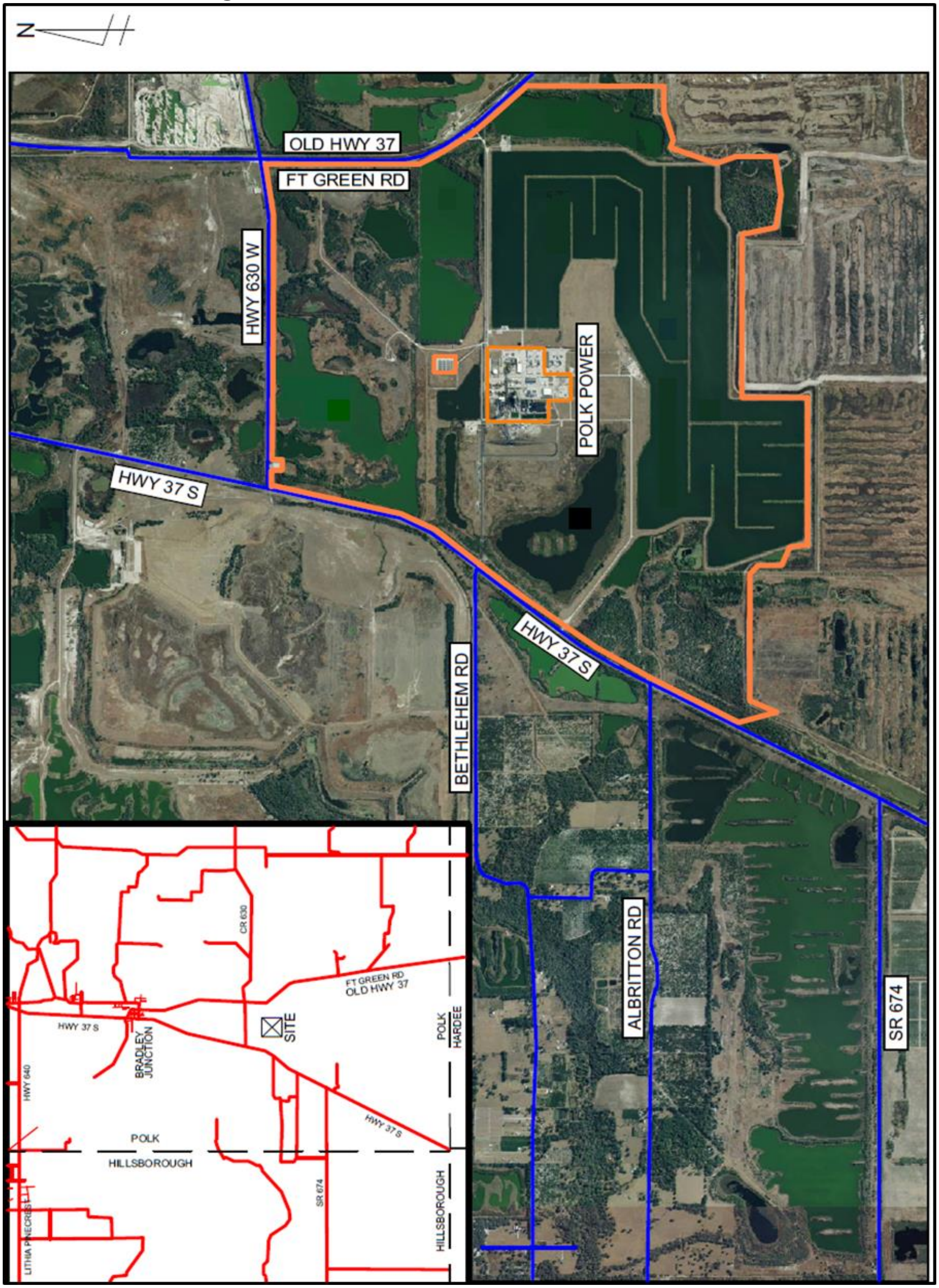

Figure VI-III: Site Location of Big Bend Power Station