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April 1, 2016

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Tampa Electric Company's 2016 Ten-Year Site Plan

Dear Ms. Stauffer

Attached for filing on behalf of Tampa Electric Company is the company's January 2016 to December 2025 Ten-Year Site Plan.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

January 2016 to December 2025

Ten-Year Site Plan

For Electrical Generating Facilities
and Associated Transmission Lines

TECO
TAMPA ELECTRIC

Responsibly Serving Our
Customers' Growing Needs

TEC030716 DP

Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2016 to December 2025

Submitted to: Florida Public Service Commission
April 1, 2016

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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
	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) 2016 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 2016-2025 time period. The 2016 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 very similar to the plan presented by TEC in 2015. As of December 2015 TEC has constructed a 1.6 MW_{AC} photovoltaic (PV) solar array located at the Tampa International Airport (TIA). TEC is currently in the process of constructing incremental capacity of 463 MW winter and 459 MW summer as part of the Polk 2 CC conversion project with a commercial operation date of January 2017. TEC has also begun the planning for an incremental 18 MW_{AC} of PV solar that will be located at Big Bend Power Station with a projected commercial operation date of May 2017. In addition, TEC plans to build future combustion turbines to meet reserve margin needs in the summer of 2020 and 2023 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 2016 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

TEC has four (4) generating stations that include fossil steam units, combined cycle units, combustion turbine peaking units, an integrated coal gasification combined cycle unit and photovoltaic generation.

Big Bend Power Station

The station operates four (4) pulverized coal-fired steam units equipped with desulfurization scrubbers, electrostatic precipitators, and selective catalytic reduction (SCR) air pollution control systems. In addition, the station operates 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. 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. In addition, the station operates four (4) natural gas fired aero-derivative combustion turbines that were placed into service in 2009.

Polk Power Station

The station operates five (5) generating units. 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. Polk Units 2 through 5 are combustion turbines fired primarily with natural gas. Unit 1 can also be fired with natural gas and Units 2 and 3 can be fired with distillate oil.

Tampa International Airport

The 6,175 fixed solar PV panels entered into service in December 2015 and are located atop the south economy parking garage at the Tampa International Airport.

Schedule 1

Existing Generating Facilities
As of December 31, 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt	Commercial	Expected	Gen. Max.	Net Capability	
Plant	Unit		Unit	Fuel		Fuel Transport		Fuel	In-Service	Retirement	Nameplate	Summer	Winter
Name	No.	Location	Type	Pri	Alt	Pri	Alt	Days	Mo/Yr	Mo/Yr	kW	MW	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
											TOTAL	**4,338**	**4,730**

Notes:

* Limited by environmental permit

** Undetermined

Figure I-I: Tampa Electric Service Area Map

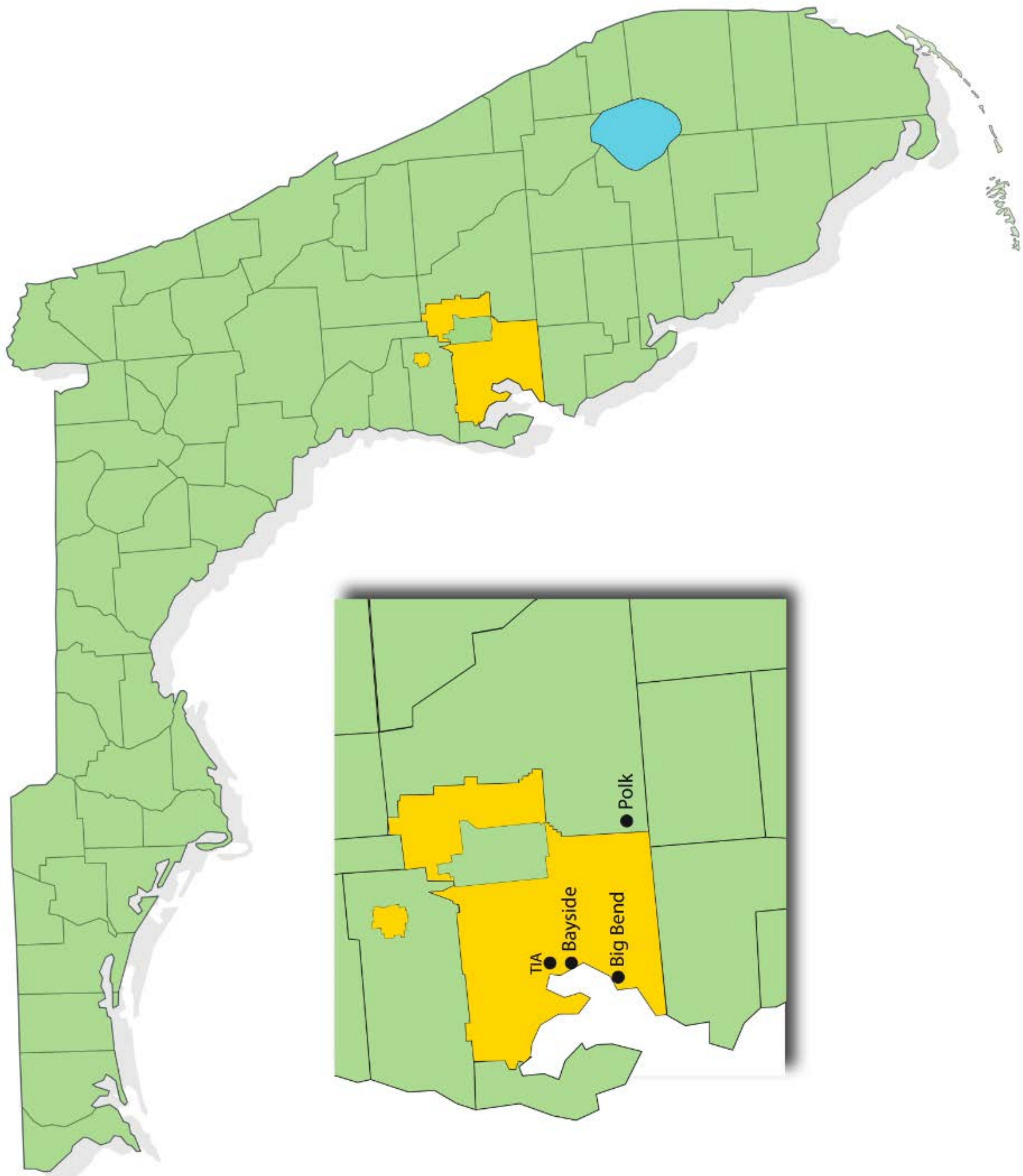

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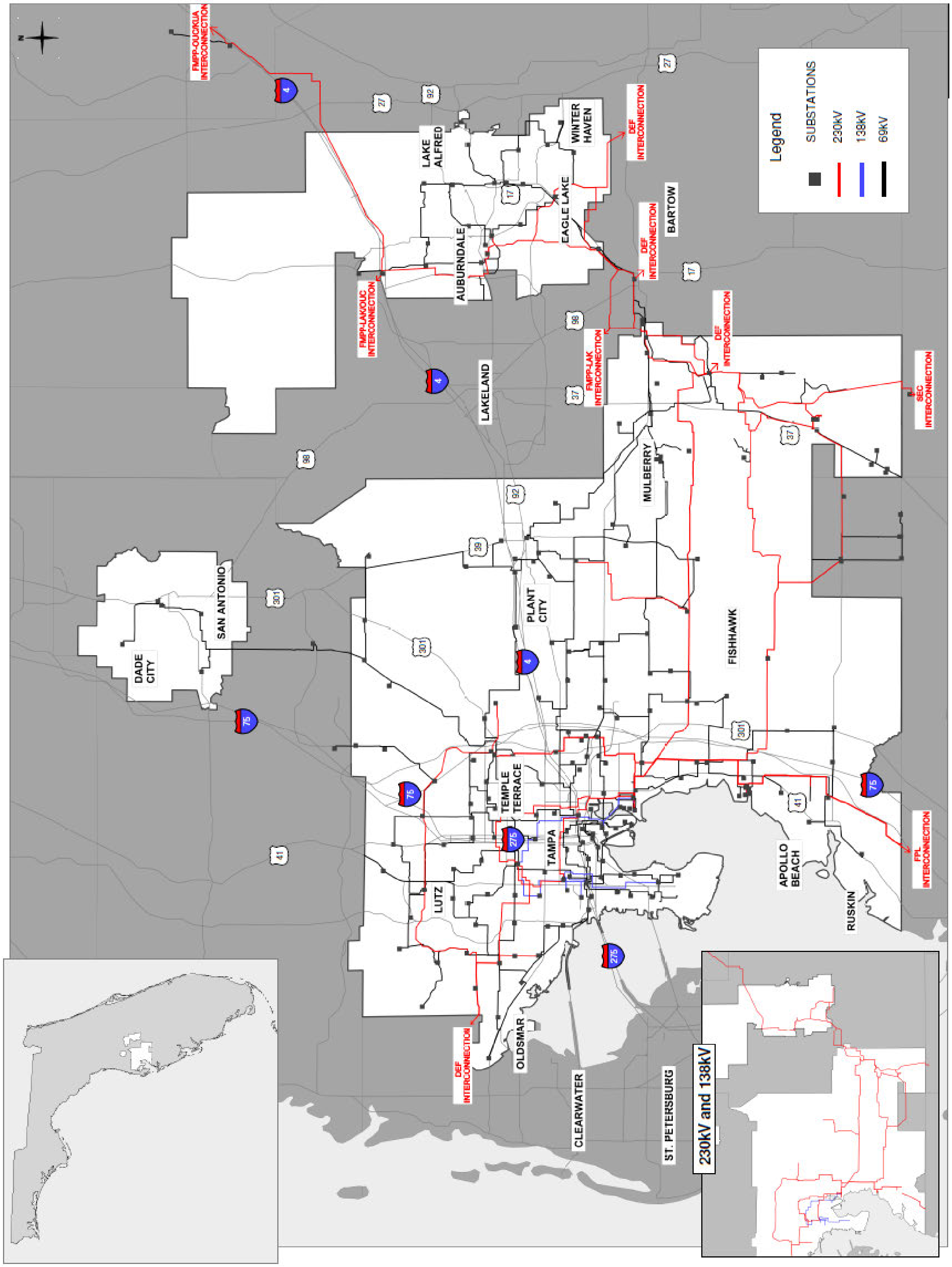
Figure I-II: Tampa Electric Service Area Transmission Facility



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Chapter II

TAMPA ELECTRIC COMPANY FORECASTING METHODOLOGY

The customer, demand and energy forecasts are the foundation from which the integrated resource plan 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 2016-2025 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the 2016-2025 time period.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2016-2025 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 Rate Class 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 General Service Customer Model 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:

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

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

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

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

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

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

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

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

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 industrial employment, 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 and 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 Rate Class 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 November 2015, TEC transitioned into the new 2015-2024 DSM Plan by discontinuing nine existing DSM programs; creating one new DSM program; the modification of twenty-eight existing programs and the retirement of the renewable energy systems initiative. This transition supports the approved FPSC goals which are reasonable, beneficial and cost-effective to all customers as required by the FEECA. The following is a list that briefly describes the company’s 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 Motors (ECM): a rebate program that encourages residential customers to replace their existing HVAC air handler motors 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. Residential Load Management (PrimeTime): an incentive program that encourages residential customers to allow the control of weather-sensitive heating, cooling and water heating systems to reduce the associated weather sensitive peak. This program is being phased out and will be fully retired by July 2016.

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

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

15. Cogeneration: an incentive program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, meet their own electrical requirements and/or sell their surplus to the company.

16. Conservation Value: a rebate program that encourages commercial and industrial customers to invest in energy efficiency and conservation measures that are not sanctioned by other commercial programs.

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

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

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

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

21. Commercial Electronically Commutated Motors (ECM): a rebate program that encourages commercial and industrial customers to replace their existing air handler motors or refrigeration fan motors with an ECM.

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

23. Lighting Conditioned Space: a rebate program that encourages commercial and industrial customers to invest in more efficient lighting technologies in existing conditioned areas of commercial and industrial facilities.

24. Lighting Non-Conditioned Space: a rebate program that encourages commercial and industrial customers to invest in more efficient lighting technologies in existing non-conditioned areas of commercial and industrial facilities.

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

26. Commercial Load Management: an incentive program that encourages commercial and industrial customers to allow for the control of weather-sensitive heating, cooling and water heating systems to reduce the associated weather sensitive peak.

27. Refrigeration Anti-Condensate Control: a rebate program that encourages commercial and industrial customers to install anti-condensate equipment sensors and control within refrigerated door systems.

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

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

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

31. Commercial Water Heating: a rebate program that encourages commercial and industrial customer to install high efficiency water heating systems.

32. Conservation Research and Development: 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 2015 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

TEC developed a Monitoring and Evaluation (M&E) plan in response to FPSC requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources.

The M&E plan has its focus on two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give TEC insight into the direction that should be taken to refine delivery processes, program standards and overall program cost-effectiveness.

TABLE III-1

Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals

Savings at the Generator

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	12.3	2.6	473.1%	10.8	1.1	981.8%	21.2	1.8	1177.8%
2016		4.1			1.6			3.5	
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

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	8.1	1.2	675.0%	11.7	1.7	688.2%	12.5	3.9	320.5%
2016		1.3			2.5			6.0	
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

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	20.4	3.8	536.8%	22.5	2.8	803.6%	33.7	5.7	591.2%
2016		5.4			4.1			9.5	
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 BEBR and Moody's Analytics supply population projections for Hillsborough County and Florida comparisons. A blend of BEBR's population growth for Hillsborough County and Moody's Analytics' population growth for Hillsborough County were used to project future growth patterns in residential customers for the period of 2016-2025. The average annual population growth rate is expected to be 1.9 percent. Moody's Analytics provides persons per household projections as an input to the residential average use model.

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 (2016-2025), employment is assumed to rise at a 1.3 percent 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 3.3 percent average annual rate from 2016-2025 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 2016-2025, real household income for Hillsborough County is expected to increase at a 2.2 percent 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 2016-2025, retail energy sales are projected to increase at a 1.1 percent annual rate. The major contributors to growth include the residential and commercial categories, increasing at an annual rate of 1.7 percent and 0.9 percent, respectively.

2. Wholesale Energy

For 2016-2018, 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 2016-2025, TEC’s base retail firm peak demand is expected to increase in the summer at an average annual rate of 1.4 percent and at rate of 1.5 percent 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 date and 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, Florida Administrative Code (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 MILP's objective function is to compare all feasible combinations of generating unit additions, satisfy the specified reliability criteria and determine the schedule and addition with the lowest revenue requirement.

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 is converting Polk Units 2-5 to a natural gas combined cycle unit with the addition of a steam turbine that will go in-service in 2017. The company is also planning the addition of a simple cycle combustion turbine in 2020 and another in 2023.

TEC will continue to assess competitive purchase power agreements that may replace or delay the next scheduled new unit. 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 F.A.C., an amount for AFUDC is recorded by the company during the construction phase of each capital project. 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 2015, TEC's Renewable Energy Program has over 1,860 customers purchasing over 2,750 blocks of renewable energy each month and there have been over 3,700 one-time blocks purchased.

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 (TIA) in December 2015. The solar PV array sized at 2 MW_{DC} (1.6 MW_{AC}) can produce enough electricity to power up to 250 homes. TEC will own the solar PV array and the electricity it produces will go to the grid to benefit all 718,713 TEC customers, including the airport. As market conditions continue to change and technology improves in this sector, renewable alternatives, such as solar, may become more cost effective. Currently, customer-owned PV installations account for almost 10 MW_{DC} of interconnected distributed generation to TEC's grid.

In addition to TIA, the company's renewable-generation portfolio is a mix of various technologies and renewable fuel sources, including seven other company owned PV arrays totaling 135 kW_{DC}. The 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. 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. 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 2015, participating customers have utilized over 76 GWh of renewable energy since the program inception.

In 2011, TEC also initiated a five-year renewable energy pilot that was retired at the end of 2015. The pilot included utilizing rebates and incentives to encourage the following installations:

1. Solar PV technologies on existing and new residential and commercial premises and solar water heating (SWH) technologies on existing and new residential premises.
2. PV on emergency shelter schools, coupled with an educational component for teachers and students.
3. SWH on low-income housing done in partnership with local non-profit building organizations.

This pilot had an annual funding cap of $1.53 million. Through the five years of this initiative, TEC provided rebates for 306 residential and commercial customer owned PV installations that resulted in approximately 2.6 MW_{DC} of customer owned generation along with 228 residential SWH systems.

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 the reliability of its 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 2015 Florida Reliability Coordinating Council (FRCC) database models, no transmission constraints that violate the criteria stated in the Transmission Reliability Criteria section of this document were identified in these studies.

TRANSMISSION RELIABILITY CRITERIA

1. Transmission

TEC system planners use the following planning reliability criteria as guidelines to assess and test the strength and limits of its transmission system to meet its load responsibility as well as to move bulk power between and among other electric systems. TEC has adopted the transmission planning criteria outlined in the *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 that 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 FRCC criteria, TEC utilizes company-specific planning criteria for normal system operation and single contingency operation, along with a Facility Rating Methodology and Facility Interconnection Requirements document available at http://www.oatioasis.com/TEC/index.html.

2. Transmission System Planning Loading Limits Criteria

The following table summarizes the Facility Rating thresholds (as described in the Facility Rating Methodology), which alert planners to problematic transmission lines and transformers found in the load flow cases provided by the FRCC as part of this filing.

Table V-I Transmission System Loading Limits	
Transmission System Conditions	**Maximum Acceptable Loading Limit for Transformers and Transmission Lines**
All elements in service	Continuous Rating
Single Contingency (pre-switching)	Short-Term Emergency Rating
Single Contingency (post-switching)	Continuous Rating
Bus Outages (pre-switching)	Short-Term Emergency Rating
Bus Outages (post-switching)	Continuous Rating

For screening purposes, the following normal and contingency voltage criteria are utilized for TEC stations:

Table V-II Transmission System Voltage Limits				
Transmission System Conditions	**Industrial Substation Buses at point-of-service**	**69 kV Buses**	**138 kV Buses**	**230 kV Buses**
Single Contingency	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 – 1.050 p.u.	0.950 - 1.060 p.u.

The discussed planning criteria are not absolute rules for system expansion. The listed 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.

3. Available Transmission Transfer Capability (ATC) Criteria

TEC adheres to the ATC calculation methodology described in the *Attachment C of Tampa Electric Company Open Access Transmission Tariff FERC Electric Tariff, Fourth Revised Volume No. 4* document, 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 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 service area 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

TEC's System Planning department ensures the TEC transmission system can support peak and off-peak system load levels without violation of the loading and voltage criteria stated in the Generation and Transmission Reliability Criteria section of this document.

2. Single Contingency Planning Criteria

The TEC transmission system is designed such that any single event outage of a transmission circuit, autotransformer, generator or shunt device, including FRCC studies of Category P1 and P2-1 events, can be removed from service up to the forecasted peak load level without any violations of the criteria stated in the Transmission Reliability Criteria section of this document.

3. Multiple Contingency Planning Criteria

Select double contingencies (including FRCC studies of Category P2-2 through P7 events) involving two or more bulk electric system transmission system elements out of service are analyzed at a variety of load levels. The TEC transmission system is designed such that double contingencies do not cause violation of FRCC and NERC Reliability Standards criteria.

4. Transmission Construction and Upgrade Plans

A specific list of the construction projects can be found in Chapter V, Schedule 10. This list represents the latest bulk electric system transmission construction related to the generation expansion plan available. However, due to the timing of this document in relationship to the company's internal planning schedule, this plan may change in the near future.

ENERGY EFFICIENCY, CONSERVATION AND ENERGY SAVINGS DURABILITY

TEC ensures that DSM programs the company offers are able to be monitored directly and yield measureable 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 using 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, direct expansion 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.

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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
2006	1,170,851	2.5	8,721	575,111	15,164	6,357	70,205	90,549
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	1,353,753	2.5	8,932	648,383	13,776	6,269	74,299	84,380
2017	1,383,164	2.5	9,073	661,597	13,714	6,334	75,093	84,347
2018	1,413,116	2.5	9,221	675,096	13,659	6,395	75,843	84,313
2019	1,442,390	2.5	9,388	688,302	13,640	6,464	76,549	84,446
2020	1,471,682	2.5	9,536	701,576	13,593	6,519	77,242	84,393
2021	1,500,078	2.5	9,683	714,546	13,551	6,561	77,910	84,214
2022	1,528,160	2.5	9,850	727,399	13,542	6,624	78,578	84,301
2023	1,555,959	2.5	10,022	740,142	13,541	6,673	79,250	84,208
2024	1,583,496	2.5	10,198	752,784	13,547	6,740	79,908	84,340
2025	1,610,563	2.5	10,375	765,225	13,558	6,806	80,538	84,505

Notes:
December 31, 2015 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
2016	1,360,381	2.5	8,990	651,513	13,798	6,283	74,458	84,386
2017	1,396,738	2.5	9,190	668,005	13,758	6,362	75,418	84,360
2018	1,433,967	2.5	9,401	684,938	13,725	6,438	76,343	84,333
2019	1,470,843	2.5	9,633	701,730	13,728	6,524	77,232	84,473
2020	1,508,067	2.5	9,849	718,745	13,703	6,595	78,115	84,427
2021	1,544,705	2.6	10,066	735,603	13,685	6,655	78,980	84,256
2022	1,582,234	2.6	10,308	752,494	13,699	6,736	79,854	84,352
2023	1,619,765	2.6	10,557	769,424	13,721	6,804	80,738	84,268
2024	1,657,329	2.6	10,814	786,400	13,751	6,889	81,617	84,411
2025	1,694,946	2.6	11,074	803,320	13,785	6,976	82,474	84,586

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
2016	1,347,125	2.5	8,875	645,254	13,755	6,256	74,141	84,374
2017	1,369,657	2.5	8,957	655,220	13,670	6,306	74,769	84,334
2018	1,392,467	2.5	9,044	665,349	13,593	6,351	75,348	84,293
2019	1,414,352	2.4	9,148	675,070	13,551	6,405	75,877	84,419
2020	1,436,003	2.4	9,232	684,741	13,482	6,444	76,386	84,358
2021	1,456,530	2.4	9,312	693,999	13,418	6,470	76,865	84,171
2022	1,476,514	2.4	9,411	703,031	13,386	6,516	77,340	84,247
2023	1,495,991	2.4	9,512	711,848	13,362	6,547	77,812	84,144
2024	1,514,987	2.4	9,615	720,460	13,345	6,595	78,266	84,266
2025	1,533,308	2.4	9,716	728,776	13,332	6,643	78,686	84,420

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

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
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	1,715	1,625	1,055,165	0	77	1,797	18,791
2017	1,721	1,648	1,044,228	0	77	1,818	19,024
2018	1,709	1,665	1,026,158	0	77	1,839	19,241
2019	1,716	1,680	1,021,928	0	77	1,864	19,511
2020	1,686	1,692	996,189	0	77	1,884	19,702
2021	1,691	1,705	991,519	0	78	1,901	19,913
2022	1,697	1,720	986,654	0	78	1,926	20,175
2023	1,532	1,734	883,203	0	78	1,945	20,251
2024	1,537	1,749	879,232	0	78	1,971	20,524
2025	1,542	1,761	875,387	0	78	1,999	20,799

Notes:
December 31, 2015 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 Consumption	Railroads and Railways	Highway Lighting	to Public Authorities	to Ultimate Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH	GWH	GWH
2016	1,717	1,627	1,055,329	0	77	1,798	18,865
2017	1,726	1,653	1,044,192	0	77	1,820	19,176
2018	1,717	1,673	1,026,165	0	77	1,841	19,475
2019	1,727	1,690	1,021,818	0	77	1,867	19,829
2020	1,699	1,706	995,867	0	77	1,888	20,109
2021	1,706	1,721	991,565	0	78	1,906	20,411
2022	1,715	1,739	986,207	0	78	1,931	20,768
2023	1,553	1,756	884,399	0	78	1,952	20,944
2024	1,561	1,774	880,070	0	78	1,979	21,321
2025	1,568	1,790	876,213	0	78	2,007	21,703

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
2016	1,712	1,622	1,055,521	0	77	1,796	18,716
2017	1,716	1,643	1,044,355	0	77	1,817	18,873
2018	1,701	1,658	1,026,130	0	77	1,837	19,011
2019	1,706	1,669	1,022,277	0	77	1,861	19,198
2020	1,673	1,679	996,474	0	77	1,880	19,306
2021	1,675	1,690	991,400	0	78	1,896	19,431
2022	1,679	1,701	986,958	0	78	1,920	19,604
2023	1,512	1,713	882,433	0	78	1,939	19,588
2024	1,515	1,725	878,091	0	78	1,964	19,766
2025	1,517	1,735	874,271	0	78	1,990	19,944

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
2006	700	1,000	20,725	6,905	653,706
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	106	910	19,806	8,214	732,522
2017	106	921	20,051	8,290	746,628
2018	106	932	20,279	8,365	760,969
2019	0	945	20,455	8,441	774,972
2020	0	954	20,657	8,517	789,027
2021	0	965	20,878	8,592	802,753
2022	0	977	21,152	8,668	816,365
2023	0	981	21,232	8,744	829,870
2024	0	995	21,519	8,819	843,260
2025	0	1,008	21,807	8,895	856,420

Notes:

December 31, 2015 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, RCID on 12/31/10, DEF on 2/28/11, WAU on 9/31/11, STC on 12/31/2012 and FPL on 12/31/12.
Forecast includes long-term firm wholesale sales to RCID, 2016 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
2016	106	913	19,884	8,214	735,812
2017	106	929	20,210	8,289	753,365
2018	106	943	20,523	8,365	771,319
2019	0	960	20,789	8,441	789,093
2020	0	974	21,082	8,516	807,082
2021	0	989	21,399	8,592	824,896
2022	0	1,006	21,774	8,668	842,755
2023	0	1,015	21,958	8,744	860,662
2024	0	1,033	22,353	8,819	878,610
2025	0	1,052	22,755	8,895	896,479

Notes:

*Forecast includes long-term firm wholesale sales to RCID, 2016 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)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
2016	106	906	19,728	8,214	729,231
2017	106	914	19,892	8,289	739,921
2018	106	921	20,037	8,365	750,720
2019	0	930	20,128	8,441	761,057
2020	0	935	20,241	8,516	771,322
2021	0	941	20,373	8,592	781,146
2022	0	950	20,553	8,668	790,740
2023	0	949	20,537	8,744	800,117
2024	0	958	20,724	8,819	809,270
2025	0	967	20,911	8,895	818,092

Notes:

*Forecast includes long-term firm wholesale sales to RCID, 2016 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) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation***	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2006	4,265	128	4,136	146	77	77	18	50	3,769
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	4,287	15	4,271	97	0	144	106	90	3,835
2017	4,353	15	4,338	96	0	149	104	93	3,896
2018	4,420	15	4,404	94	0	154	105	97	3,955
2019	4,475	0	4,475	94	0	159	106	101	4,015
2020	4,539	0	4,539	91	0	165	107	105	4,071
2021	4,604	0	4,604	92	0	171	108	109	4,123
2022	4,674	0	4,674	92	0	177	110	114	4,181
2023	4,725	0	4,725	76	0	183	111	118	4,237
2024	4,796	0	4,796	76	0	189	112	122	4,297
2025	4,867	0	4,867	76	0	195	113	127	4,356

Notes:

December 31, 2015 Status
2010 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, RCID on 12/31/10, DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12 and FP&L on 12/31/12.
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
2016	4,303	15	4,287	97	0	144	106	90	3,851
2017	4,388	15	4,373	96	0	149	104	93	3,931
2018	4,473	15	4,457	94	0	154	105	97	4,008
2019	4,548	0	4,548	94	0	159	106	101	4,088
2020	4,631	0	4,631	91	0	165	107	105	4,163
2021	4,717	0	4,717	92	0	171	108	109	4,236
2022	4,809	0	4,809	92	0	177	110	114	4,316
2023	4,883	0	4,883	76	0	183	111	118	4,395
2024	4,977	0	4,977	76	0	189	112	122	4,478
2025	5,072	0	5,072	76	0	195	113	127	4,561

Notes:
*Includes residential and commercial/industrial conservation.
**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)
Low Case

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation***	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2016	4,270	15	4,254	97	0	144	106	90	3,818
2017	4,319	15	4,304	96	0	149	104	93	3,862
2018	4,368	15	4,352	94	0	154	105	97	3,903
2019	4,404	0	4,404	94	0	159	106	101	3,944
2020	4,448	0	4,448	91	0	165	107	105	3,980
2021	4,494	0	4,494	92	0	171	108	109	4,013
2022	4,543	0	4,543	92	0	177	110	114	4,050
2023	4,574	0	4,574	76	0	183	111	118	4,086
2024	4,623	0	4,623	76	0	189	112	122	4,124
2025	4,672	0	4,672	76	0	195	113	127	4,161

Notes:
*Includes residential and commercial/industrial conservation.
**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

History and Forecast of Winter Peak Demand (MW)
Base Case

(1) Year	(2) Total *	(3) Wholesale **	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation***	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
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	4,764	15	4,749	90	11	529	112	67	3,940
2016/17	4,837	15	4,822	89	0	536	113	68	4,016
2017/18	4,907	15	4,892	87	0	544	114	69	4,078
2018/19	4,967	0	4,967	87	0	551	116	70	4,142
2019/20	5,037	0	5,037	83	0	560	117	72	4,205
2020/21	5,107	0	5,107	83	0	569	118	74	4,264
2021/22	5,179	0	5,179	84	0	577	119	75	4,323
2022/23	5,236	0	5,236	69	0	586	120	77	4,384
2023/24	5,309	0	5,309	67	0	594	121	79	4,448
2024/25	5,385	0	5,385	69	0	603	123	81	4,509

Notes:

December 31, 2015 Status
2011/2012 Net Firm Demand is not coincident with system peak
*Includes residential and commercial/industrial conservation.
**Includes sales to DEF, WAU, FTM, STC, RCID and FPL.
Contract ended with FTM on 12/31/08, RCID on 12/31/10, DEF on 2/28/11, WAU on 9/31/11, STC on 12/31/2012 and FPL on 12/31/12.
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
2015/16	4,782	15	4,767	90	11	529	112	67	3,958
2016/17	4,873	15	4,858	89	0	536	113	68	4,052
2017/18	4,962	15	4,947	87	0	544	114	69	4,133
2018/19	5,042	0	5,042	87	0	551	116	70	4,217
2019/20	5,133	0	5,133	83	0	560	117	72	4,301
2020/21	5,224	0	5,224	83	0	569	118	74	4,381
2021/22	5,319	0	5,319	84	0	577	119	75	4,463
2022/23	5,399	0	5,399	69	0	586	120	77	4,547
2023/24	5,496	0	5,496	67	0	594	121	79	4,635
2024/25	5,598	0	5,598	69	0	603	123	81	4,722

Notes:
*Includes residential and commercial/industrial conservation.
**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)
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
2015/16	4,746	15	4,731	90	11	529	112	67	3,922
2016/17	4,801	15	4,786	89	0	536	113	68	3,980
2017/18	4,853	15	4,838	87	0	544	114	69	4,024
2018/19	4,893	0	4,893	87	0	551	116	70	4,068
2019/20	4,944	0	4,944	83	0	560	117	72	4,112
2020/21	4,993	0	4,993	83	0	569	118	74	4,150
2021/22	5,044	0	5,044	84	0	577	119	75	4,188
2022/23	5,079	0	5,079	69	0	586	120	77	4,227
2023/24	5,130	0	5,130	67	0	594	121	79	4,269
2024/25	5,183	0	5,183	69	0	603	123	81	4,307

Notes:
*Includes residential and commercial/industrial conservation.
**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 3.3

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 %
2006	19,625	412	188	19,025	700	1,000	20,725	57.2
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	19,692	578	324	18,791	106	910	19,806	54.1
2017	19,949	591	334	19,024	106	921	20,051	54.1
2018	20,191	605	344	19,241	106	932	20,279	53.9
2019	20,486	620	355	19,511	0	945	20,455	53.7
2020	20,706	636	368	19,702	0	954	20,657	53.4
2021	20,946	651	381	19,913	0	965	20,878	53.4
2022	21,236	666	395	20,175	0	977	21,152	53.4
2023	21,341	681	408	20,251	0	981	21,232	53.0
2024	21,643	697	422	20,524	0	995	21,519	52.8
2025	21,947	712	436	20,799	0	1,008	21,807	53.0

Notes:

December 31, 2015 Status
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Includes sales to DEF, WAU, FTM, STC, RCID and FPL.
Contract ended with FTM on 12/31/08, RCID on 12/31/10, DEF on 2/28/11, WAU on 9/31/11, STC on 12/31/2012 and FPL on 12/31/12.
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) Year	(2) Total*	(3) Residential Conservation**	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale***	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load **** Factor %
2016	19,766	578	324	18,865	106	913	19,884	54.1
2017	20,101	591	334	19,176	106	929	20,210	54.0
2018	20,424	605	344	19,475	106	943	20,523	53.9
2019	20,804	620	355	19,829	0	960	20,789	53.7
2020	21,112	636	368	20,109	0	974	21,082	53.3
2021	21,443	651	381	20,411	0	989	21,399	53.3
2022	21,829	666	395	20,768	0	1,006	21,774	53.3
2023	22,034	681	408	20,944	0	1,015	21,958	52.9
2024	22,439	697	422	21,321	0	1,033	22,353	52.8
2025	22,850	712	436	21,703	0	1,052	22,755	52.9

Notes:

*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***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)
Low Case

(1) Year	(2) Total*	(3) Residential Conservation**	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale ***	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load **** Factor %
2016	19,618	578	324	18,716	106	906	19,728	54.1
2017	19,798	591	334	18,873	106	914	19,892	54.1
2018	19,961	605	344	19,011	106	921	20,037	53.9
2019	20,174	620	355	19,198	0	930	20,128	53.8
2020	20,310	636	368	19,306	0	935	20,241	53.4
2021	20,435	651	381	19,431	0	941	20,373	53.5
2022	20,636	666	395	19,604	0	950	20,553	53.4
2023	20,649	681	408	19,588	0	949	20,537	53.1
2024	20,856	697	422	19,766	0	958	20,724	52.9
2025	21,063	712	436	19,944	0	967	20,911	53.1

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***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 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)
	2015 Actual		2016 Forecast		2017 Forecast	
Month	Peak Demand * MW	NEL GWH	Peak Demand * MW	NEL GWH	Peak Demand * MW	NEL GWH
January	2,760	1,419	4,168	1,505	4,233	1,526
February	3,609	1,317	3,470	1,338	3,520	1,353
March	2,997	1,508	3,206	1,446	3,251	1,465
April	3,352	1,669	3,464	1,508	3,512	1,527
May	3,758	1,835	3,690	1,767	3,744	1,790
June	3,892	1,898	3,954	1,909	4,014	1,932
July	3,868	1,909	3,981	1,968	4,038	1,992
August	4,013	1,954	4,053	2,000	4,111	2,024
September	3,880	1,838	3,764	1,853	3,817	1,875
October	3,337	1,653	3,575	1,662	3,625	1,682
November	3,424	1,565	2,966	1,369	3,005	1,386
December	3,003	1,542	3,602	1,481	3,654	1,498
TOTAL		**20,105**		**19,806**		**20,051**

Notes:
December 31, 2015 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)
	2015 Actual		2016 Forecast		2017 Forecast	
Month	Peak Demand * MW	NEL GWH	Peak Demand * MW	NEL GWH	Peak Demand * MW	NEL GWH
January	2,760	1,419	4,186	1,511	4,269	1,538
February	3,609	1,317	3,484	1,343	3,550	1,364
March	2,997	1,508	3,219	1,451	3,278	1,476
April	3,352	1,669	3,479	1,513	3,541	1,539
May	3,758	1,835	3,706	1,774	3,776	1,804
June	3,892	1,898	3,971	1,916	4,048	1,948
July	3,868	1,909	3,998	1,976	4,072	2,009
August	4,013	1,954	4,069	2,008	4,146	2,041
September	3,880	1,838	3,779	1,861	3,849	1,890
October	3,337	1,653	3,590	1,669	3,655	1,696
November	3,424	1,565	2,978	1,375	3,029	1,396
December	3,003	1,542	3,617	1,487	3,684	1,510
TOTAL		**20,105**		**19,884**		**20,210**

Notes:
December 31, 2015 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)
	2015 Actual		2016 Forecast		2017 Forecast	
Month	Peak Demand * MW	NEL GWH	Peak Demand * MW	NEL GWH	Peak Demand * MW	NEL GWH
January	2,760	1,419	4,150	1,499	4,197	1,514
February	3,609	1,317	3,455	1,333	3,491	1,343
March	2,997	1,508	3,193	1,441	3,225	1,454
April	3,352	1,669	3,450	1,502	3,482	1,516
May	3,758	1,835	3,675	1,760	3,713	1,776
June	3,892	1,898	3,938	1,901	3,980	1,917
July	3,868	1,909	3,965	1,960	4,005	1,976
August	4,013	1,954	4,036	1,992	4,077	2,008
September	3,880	1,838	3,748	1,845	3,785	1,859
October	3,337	1,653	3,561	1,656	3,595	1,669
November	3,424	1,565	2,954	1,364	2,981	1,375
December	3,003	1,542	3,588	1,475	3,624	1,487
TOTAL		**20,105**		**19,728**		**19,892**

Notes:
December 31, 2015 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
Values shown may be affected due to rounding.

Schedule 5

History and Forecast of Fuel Requirements
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements	Unit	Actual 2014	Actual 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	4,557	3,682	3,652	3,942	3,844	3,836	3,986	3,955	4,045	4,135	4,123	4,125
(3)	Residual	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)	CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)	GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)	D	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	1000 BBL	0	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	0	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	51,608	74,847	70,022	71,226	75,395	76,461	74,703	77,443	77,708	76,628	79,294	80,612
(14)	ST	1000 MCF	0	0	17,592	4,453	4,353	4,330	4,512	4,497	4,584	4,680	4,675	4,676
(15)	CC	1000 MCF	49,498	66,304	50,236	66,194	70,520	71,819	69,571	72,172	71,562	71,061	73,244	74,212
(16)	GT	1000 MCF	2,110	8,543	2,194	579	522	312	620	774	1,562	887	1,375	1,724
(17)	Other (Specify)													
(18)	PC	1000 Ton	433	325	444	461	432	461	463	421	461	461	434	461

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 2014	Actual 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
(1)	Annual Firm Interchange	GWh	194	438	1,806	51	23	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	10,383	8,208	7,942	8,560	8,322	8,254	8,746	8,665	8,888	9,082	9,063	9,078
(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	7,116	9,919	8,769	10,053	10,603	10,801	10,517	10,924	10,842	10,765	11,136	11,321
(15)	ST	GWh	0	0	1,650	437	425	421	447	444	454	464	464	464
(16)	CC	GWh	6,937	9,161	6,927	9,564	10,132	10,352	10,016	10,412	10,251	10,225	10,553	10,707
(17)	GT	GWh	179	758	192	52	46	28	54	68	137	76	119	150
(18)	Renewable	GWh	-	0	3	34	49	48	48	48	47	47	47	46
(19)	Solar	GWh	-	0	3	34	49	48	48	48	47	47	47	46
(20)	Other (Specify)													
(21)	PC	GWh	1,212	911	1,199	1,245	1,166	1,245	1,249	1,135	1,245	1,245	1,170	1,245
(22)	Net Interchange	GWh	139	289	2	18	26	15	6	17	40	3	12	27
(23)	Purchased Energy from Non-Utility Generators	GWh	272	341	85	90	90	92	91	89	90	90	90	90
(24)	Net Energy for Load	GWh	19,315	20,105	19,806	20,051	20,279	20,455	20,657	20,878	21,152	21,232	21,519	21,807

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 2014**	**Actual 2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
(1)	Annual Firm Interchange	%	1.0	2.2	9.1	0.3	0.1	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	%	53.8	40.8	40.1	42.7	41.0	40.4	42.3	41.5	42.0	42.8	42.1	41.6
(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	%	36.8	49.3	44.3	50.1	52.3	52.8	50.9	52.3	51.3	50.7	51.7	51.9
(15)	ST	%	0.0	0.0	8.3	2.2	2.1	2.1	2.2	2.1	2.1	2.2	2.2	2.1
(16)	CC	%	35.9	45.6	35.0	47.7	50.0	50.6	48.5	49.9	48.5	48.2	49.0	49.1
(17)	GT	%	0.9	3.8	1.0	0.3	0.2	0.1	0.3	0.3	0.6	0.4	0.6	0.7
(18)	Renewable	%	-	0.0	0.0	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
(20)	Other (Specify)													
(21)	PC	%	6.3	4.5	6.1	6.2	5.7	6.1	6.0	5.4	5.9	5.9	5.4	5.7
(22)	Net Interchange	%	0.7	1.4	0.0	0.1	0.1	0.1	0.0	0.1	0.2	0.0	0.1	0.1
(23)	Purchased Energy from													
(24)	Non-Utility Generators	%	1.4	1.7	0.4	0.4	0.4	0.5	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 IRP process is included in Chapter V.

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 meet its intermediate load needs by converting Polk Power Station's simple cycle combustion turbines (Polk Units 2-5) to a waste heat recovery natural gas combined cycle (NGCC) unit. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 9. TEC also plans to build an 18 MW_{AC} PV solar array that will be located at Big Bend Station in 2017. Beyond 2017, the company foresees the future needs being that of additional peaking capacity in 2020 and 2023, which it proposes to meet by combustion turbine 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 2016, TEC plans for 340 MW of cogeneration capacity operating in its service area.

Table IV-I 2016 Cogeneration Capacity Forecast	Capacity (MW)
Self-service [1]	272
Firm to Tampa Electric	0
As-available to Tampa Electric	13
Export to other systems	55
Total	340

[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) begins January 1, 2016 and extends through December 31, 2018.
- 117 MW purchase from Calpine Energy Services through December 2016
- 121 MW purchase from Quantum Pasco Power through December 2018
- 250 MW purchase from Duke Energy Florida begins February 1, 2016 and extends through February 28, 2017
- 100 MW purchase from Florida Power & Light begins May 1, 2016 and extends through November 30, 2016
- 150 MW purchase from Constellation, an Exelon Company, begins May 1, 2016 and extends through November 30, 2016

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 2016 coal and petcoke will fuel 46.2 percent of the net energy for load and natural gas will fuel 44.3 percent. The remaining net energy for load is served by firm, non-firm, and non-utility generator purchases. Some of the company's natural gas 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 (SO2) by 94 percent, nitrogen oxides (NOx) by 91 percent, particulate matter by 87 percent and mercury emissions by 90 percent. These reductions were the result of a December 1999 Consent Final Judgment 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 2016 will continue to provide opportunities to augment coal-fired operation and further reduce emissions during startup and normal operation.
- Ongoing installation of the 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 (CCRs), 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 (CCR) Rule 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 stormwater 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)
Year	Firm Installed Capacity MW	Firm * Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2016	4,337	738	15	0	5,060	3,835	1,224	32%	302	922	24%
2017	4,804	121	15	0	4,910	3,896	1,013	26%	0	1,013	26%
2018	4,804	121	15	0	4,910	3,955	955	24%	0	955	24%
2019	4,804	0	0	0	4,804	4,015	789	20%	0	789	20%
2020	5,007	0	0	0	5,007	4,071	937	23%	0	937	23%
2021	5,007	0	0	0	5,007	4,123	885	21%	0	885	21%
2022	5,007	0	0	0	5,007	4,181	826	20%	0	826	20%
2023	5,211	0	0	0	5,211	4,237	974	23%	0	974	23%
2024	5,211	0	0	0	5,211	4,297	914	21%	0	914	21%
2025	5,211	0	0	0	5,211	4,356	855	20%	0	855	20%

Notes:

* Includes purchase power agreements (PPA) with Calpine Energy Services of 117 MW through 2016, Exelon Generation Company LLC of 150 MW May-Nov 2016, Florida Power & Light of 100 MW May-Nov 2016, Duke Energy Florida LLC of 250 MW Feb 2016-Feb 2017, and 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
2015-16	4,728	488	15	0	5,201	3,940	1,261	32%	0	1,261	32%
2016-17	5,191	371	15	0	5,547	4,016	1,531	38%	0	1,531	38%
2017-18	5,191	121	15	0	5,297	4,078	1,219	30%	0	1,219	30%
2018-19	5,191	0	0	0	5,191	4,142	1,049	25%	0	1,049	25%
2019-20	5,191	0	0	0	5,191	4,205	986	23%	0	986	23%
2020-21	5,411	0	0	0	5,411	4,264	1,147	27%	0	1,147	27%
2021-22	5,411	0	0	0	5,411	4,323	1,088	25%	0	1,088	25%
2022-23	5,411	0	0	0	5,411	4,384	1,027	23%	0	1,027	23%
2023-24	5,631	0	0	0	5,631	4,448	1,184	27%	0	1,184	27%
2024-25	5,631	0	0	0	5,631	4,509	1,122	25%	0	1,122	25%

Notes:

* Includes purchase power agreements (PPA) with Calpine Energy Services of 117 MW through 2016, Exelon Generation Company LLC of 150 MW May-Nov 2016, Florida Power & Light of 100 MW May-Nov 2016, Duke Energy Florida LLC of 250 MW Feb 2016-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.		Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	Winter MW	Status
Polk 2 CC	2	Polk	CC	NG	DFO	PL	TK	01/14	01/17	*	*	1,063 **	1,195 **	U
Big Bend Solar	1	Big Bend	PV	SOLAR	NA	NA	NA	5/16	5/17	*	*	18	18	P
Future CT 1	1	*	GT	NG	NA	PL	NA	09/19	05/20	*	*	204	220	P
Future CT 2	1	*	GT	NG	NA	PL	NA	09/22	5/23	*	*	204	220	P

Notes:

* Undetermined

** Net capability values shown for the Polk 2 CC reflect the conversion of the existing Polk Units 2-5 to a natural gas CC unit in 2017.
Incremental capacity gain from the conversion is 459 MW summer and 463 MW winter.

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

Schedule 9
(Page 1 of 4)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Polk 2 CC
(2)	Net Capability	
	A. Summer	1,063 MW
	B. Winter	1,195 MW
(3)	Technology Type	Combined Cycle
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	Jan 2014
	B. Commercial In-Service Date	Jan 2017
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	Light Oil
(6)	Air Pollution Control Strategy	SCR, Dry-Low NO_x Burners
(7)	Cooling Method	Cooling Reservoir
(8)	Total Site Area	Undetermined
(9)	Construction Status	In Progress
(10)	Certification Status	In Progress
(11)	Status with Federal Agencies	All Federal Permits Received
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.03
	Forced Outage Factor (FOF)	0.01
	Equivalent Availability Factor (EAF)	0.96
	Resulting Capacity Factor (2017)	52.3 %
	Average Net Operating Heat Rate (ANOHR) [1]	7,049 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	423.60
	Direct Construction Cost ($/kW) [1]	355.17
	AFUDC* Amount ($/kW) [1]	45.65
	Escalation ($/kW) [1]	22.78
	Fixed O&M ($/kW – Yr) [1]	1.23
	Variable O&M ($/MWh) [1]	2.34
	K-Factor	1.5245

[1] Based on In-Service Year.
* Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 2 of 4)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend Solar
(2)	Net Capability	
	A. Summer	18 MW_{AC}
	B. Winter	18 MW_{AC}
(3)	Technology Type	Photovoltaic (PV)
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	May 2016
	B. Commercial In-Service Date	May 2017
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	106 Acres
(9)	Construction Status	Planned
(10)	Certification Status	Planned
(11)	Status with Federal Agencies	Planned
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2017)	N/A
	Average Net Operating Heat Rate (ANOHR) [1]	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	2,149.57
	Direct Construction Cost ($/kW) [1]	2,136.22
	AFUDC* Amount ($/kW) [1]	-
	Escalation ($/kW) [1]	13.35
	Fixed O&M ($/kW – Yr) [1]	14.44
	Variable O&M ($/MWh) [1]	-
	K-Factor	1.1381

[1] Based on In-Service Year.
* Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 3 of 4)
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	Sep 2019
	B. Commercial In-Service Date	May 2020
(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 (2020)	6.5 %
	Average Net Operating Heat Rate (ANOHR) [1]	10,780 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	806.61
	Direct Construction Cost ($/kW) [1]	589.56
	AFUDC* Amount ($/kW) [1]	54.92
	Escalation ($/kW) [1]	162.14
	Fixed O&M ($/kW – Yr) [1]	13.18
	Variable O&M ($/MWh) [1]	2.12
	K-Factor	1.3834

[1] Based on In-Service Year.
* Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 4 of 4)
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	Sep 2022
	B. Commercial In-Service Date	May 2023
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.04
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.94
	Resulting Capacity Factor (2023)	6.5 %
	Average Net Operating Heat Rate (ANOHR) [1]	10,780 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	827.22
	Direct Construction Cost ($/kW) [1]	559.59
	AFUDC* Amount ($/kW) [1]	84.88
	Escalation ($/kW) [1]	182.74
	Fixed O&M ($/kW – Yr) [1]	14.15
	Variable O&M ($/MWh) [1]	2.28
	K-Factor	1.4416

[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
Polk 2 CC	Po k-Aspen; Aspen-FishHawk Ck1 & Ck2; Big-Aspen Ck1 & Ck2; Po k-Pebbledale Ck1 & Ck2; Davis-Chapman Ck1 & Ck2	9	New ROW not required	51 mi	230 kV	Jan. 2017	$96 million	Switching Station	None
Polk 2 CC	Polk Steam Turbine Interconnect & Upgrade	1	New ROW not required	0.7 mi	230 kV	Jan. 2017	$11 million	No New substations	None
Future CT 1	Unsited *	-	-	-	-	May 2020	-	-	-
Future CT 2	Unsited *	-	-	-	-	May 2023	-	-	-

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 IV 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

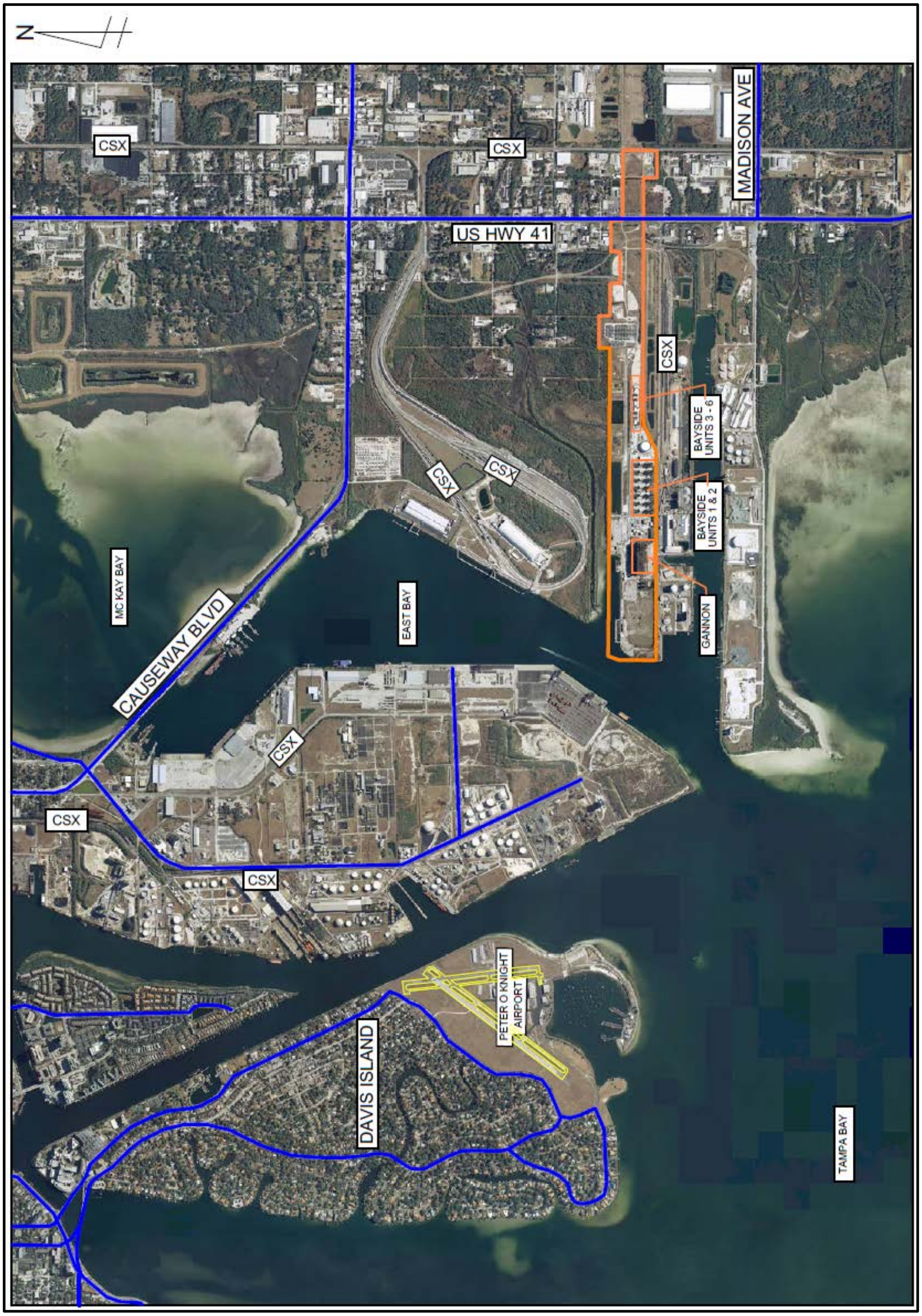

Figure VI-II: Site Location of Polk Power Station

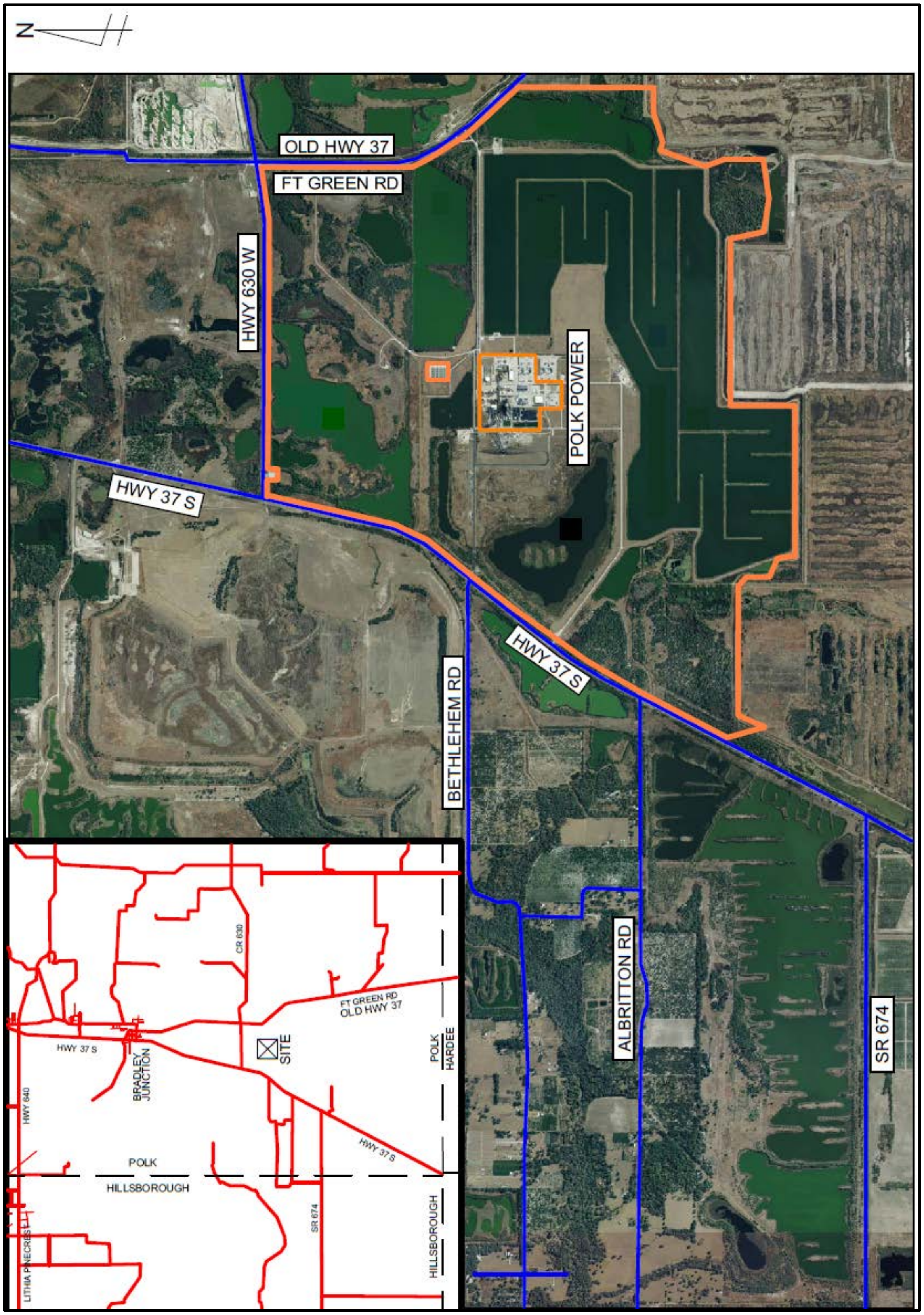

Figure VI-III: Site Location of Big Bend Power Station