Ten-Year Site Plan

JANUARY 2024 – DECEMBER 2033

For Electrical Generating Facilities and Associated Transmission Lines

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2024 to December 2033

April 1, 2024

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GLOSSARY OF TERMS

CODE IDENTIFICATION SHEET

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

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Executive Summary

Tampa Electric Company's (TEC or the company) 2024 Ten-Year Site Plan (TYSP or Plan) features plans to enhance electric generating and storage capability to meet projected incremental resource needs for 2024 through 2033. This Plan provides the Florida Public Service Commission (FPSC) assurances that TEC will have cost effective options to ensure the delivery of adequate, safe, environmentally responsible, and reliable power to its customers.

TEC's systems and facilities for generating electricity have evolved over time to embrace new technologies, environmental considerations, public policy changes, and the economics of electric generation. The company transitioned from oil generation to coal after the oil embargos of the 1970s and from coal to gas as environmental concerns about coal increased and the price of gas decreased.

The company added its first 600 MW of solar generation beginning in 2017 and added another 595 MW beginning in 2021, in both instances based on regulatory agreements approved by the FPSC. About eight percent of the energy we generated in 2023 came from the sun, and we expect our solar generation to be approximately 13 percent by the end of 2024.

The company recently completed its modernization project at Big Bend Station. The company retired Big Bend Unit 2 and Unit 3, refurbished the Big Bend Unit 1 steam turbine and generator, and replaced the Unit 1 boiler and coal processing equipment with two new, highly efficient General Electric 7HA.02 combustion turbines and associated heat recovery steam generators. These changes improved our system reliability and operating flexibility, reduced fuel costs, increased the combined winter generating capacity of Units 1 and 2 from approximately 800 MW to 1,120 MW, and reduced their combined heat rates from over 10,500 Btu/kWh to about 6,300 Btu/kWh – a 40 percent efficiency gain.

The fuel efficiency of our combined generating system has improved by 20 percent since 2017. These changes, along with other improvements and the addition of solar generation, have significantly reduced customers' fuel costs, along with reducing annual emissions by about 38 percent since 2017.

The company is diligently and thoughtfully planning to improve the safety, reliability, and resilience of our electric system and improve efficiency in all areas of our operations - especially the generating efficiency of our existing power plants. The company plans to meet the power needs of its customers through additional resources and will do so in a cost-effective way.

We are continuing to transform our energy supply system as reflected by the projects in this document, which include:

1. Adding 1.5 GW of incremental solar generation to promote fuel diversity, protect customers from fuel price volatility, and lower fuel costs on customers' bills. These additions will bring our total committed solar capacity to nearly 2,800 MW or approximately 34% of our total summer installed capacity by the end of the study horizon.

2. Installing a small distributed energy project that will help the company avoid costly transmission system upgrades, increase system resilience, reduce line losses, provide peaking capacity and fuel savings, and support national security as part of our South Tampa Resilience Project.

3. Constructing approximately 185 MW of energy storage capacity as the most cost-effective means to maintain reserve margins and provide additional resilience in the event of extreme weather events. This energy storage will allow us to serve customers with lower-cost energy during peaks, thereby reducing our reliance on fuels purchased from sources beyond Florida.

These resource additions are based on TEC's Integrated Resource Planning (IRP) process, which incorporates an ongoing evaluation of demand-side and supply-side resources on a comparable and consistent basis to satisfy future demand and energy requirements in a cost-effective, reliable, and environmentally responsible manner that reduces reliance on natural gas and its associated price volatility risk for customers.

TEC is also committed to pursuing cost-effective improvements on the existing generating fleet. In 2024, Bayside Unit 2 will undergo advanced hardware upgrades to improve efficiency, generating capacity, and operational flexibility to its four (4) CTs. We also have plans to modify existing power plants (Polk Fuel Diversity Project and Polk one simple cycle conversion) to improve performance, increase fuel resilience, reduce sustaining capital and operations and maintenance costs, increase generating fleet flexibility, and enhance system reliability.

Tampa Electric Company's current and planned generating and storage resources will meet operating reserve requirements under normal peak demand scenarios. The reserve margin provides operating flexibility in the case of unplanned outages and deviations to load from colder than normal (or hotter than normal) weather. However, temperatures that vary significantly from those used to prepare this plan would result in the need to employ mitigations under extreme weather conditions such as switching to alternate fuels, making full use of demand response, pursuing purchase power agreements and potentially interrupting customers.

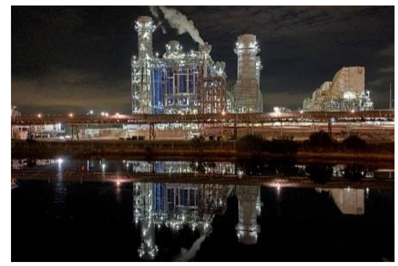
The portfolio of resource additions presented in this TYSP will operate in concert to provide cost savings, price stability, and reliability benefits for customers and will enhance our system's operational flexibility, energy diversity, and resiliency.

Chapter I

DESCRIPTION OF EXISTING FACILITIES

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

Big Bend Power Station



Big Bend Station is composed of one (1) combined cycle unit, Unit 1, which utilizes two (2) natural gas fueled combustion turbines that supply waste heat for reuse by the Unit 1 steam turbine via two (2) heat recovery steam generators (HRSGs). Big Bend also has one (1) steam unit, Big Bend Unit 4. The steam unit is equipped with desulfurization scrubbers, electrostatic precipitators, and Selective Catalytic Reduction air pollution control systems. Big Bend Unit 4 can be fired with coal and natural gas. Big Bend CT 4 is a natural gas aero-derivative combustion turbine.

H.L. Culbreath "Bayside" Power Station

The Bayside station consists of two (2) natural gas-fired combined cycle units and four (4) aero derivative combustion turbines. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) HRSGs and one (1) steam turbine. Bayside Unit 2 utilizes four (4) combustion turbines, four (4) HRSGs and one (1) steam turbine. Bayside 3, 4, 5, and 6 are four (4) natural gas fired aero-derivative combustion turbines.

Polk Power Station

Polk Unit 1 is a dual fuel natural gas / IGCC unit consisting of one (1) combustion turbine, one (1) HSRG, and one (1) steam turbine. Polk 2 Combined Cycle utilizes four (4) natural gas-fired combustion turbines, four (4) HRSGs and one (1) steam turbine. Two (2) of the combustion turbines can also be fired with distillate oil.

Solar

As of December 31, 2023, TEC owns 1,252 MW_{AC} of solar throughout our territory. It consists of primarily single axis tracking PV solar array sites throughout Hillsborough, Pasco, and Polk counties, and several large-scale, fixed-tilt systems on rooftops, carports, and ground mount. Tampa Electric also has a 1.0 MW_{AC} floating solar project located at Big Bend Power Station, and an integrated renewable energy system, consisting of solar PV carports that charge commercial-sized batteries, which re-charge the company's growing EV fleet.

Schedule 1
Existing Generating Facilities
As of December 31, 2023

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days	(10) Commercial In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen. Max. Nameplate kW	(13) Net Capability Summer MW	(14) Net Capability Winter MW
Big Bend		**Hillsborough Co.**											
	1		CC	NG	NA	PL	NA	NA	12/22	**	1,241,100	1,055	1,120
	4		ST	NG	BIT	PL	WA/RR	NA	02/85	01/40	486,000	437	442
	CT 4		GT	NG	NA	PL	NA	NA	08/09	**	69,900	56	61
Big Bend Total [4]											**1,797,000**	**1,548**	**1,623**
Bayside		**Hillsborough Co.**											
	1		CC	NG	NA	PL	NA	NA	04/03	04/38	914,000	749	847
	2		CC	NG	NA	PL	NA	NA	01/04	01/39	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
Bayside Total											**2,398,699**	**1,902**	**2,138**
Polk		**Polk Co.**											
	1		IGCC	NG	PC/BIT	PL	WA/TK	*	09/96	09/36	326,299	220	220
	2		CC	NG	DFO	PL	TK	*	01/17	**	1,216,080	1,061	1,200
Polk Total											**1,542,379**	**1,281**	**1,420**
TIA	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	12/15	**	1,600	1.6	1.6
LEGOLAND®	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	12/16	**	1,400	1.4	1.4
Big Bend Solar [1]	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	02/17	**	19,800	19.8	19.8
Payne Creek Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	09/18	**	70,300	70.3	70.3
Balm Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	09/18	**	74,400	74.4	74.4
Lithia Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	01/19	**	74,500	74.5	74.5
Grange Hall Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	01/19	**	61,100	61.1	61.1
Bonnie Mine Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	01/19	**	37,500	37.5	37.5
Peace Creek Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	03/19	**	55,400	55.4	55.4
Lake Hancock Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	04/19	**	49,500	49.5	49.5
Little Manatee River Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	02/20	**	74,500	74.5	74.5
Wimauma Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	04/20	**	74,800	74.8	74.8
Durrance Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	01/21	**	60,000	60.0	60.0
Magnolia Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	12/21	**	74,500	74.5	74.5
Big Bend II Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	01/22	**	45,800	45.8	45.8
Big Bend Floating Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	03/22	**	1,000	1.0	1.0
Mountain View Solar	**1**	**Pasco Co.**	PV	SOLAR	NA	NA	NA	NA	04/22	**	54,600	54.6	54.6
Jamison Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	04/22	**	74,500	74.5	74.5
Big Bend Agrivoltaic	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	06/22	**	1,000	1.0	1.0
Laurel Oaks Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	12/22	**	61,200	61.2	61.2
Riverside Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	12/22	**	55,200	55.2	55.2
Juniper Solar	**1**	**Pasco Co.**	PV	SOLAR	NA	NA	NA	NA	12/23	**	70,000	70.0	70.0
Alafia Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	12/23	**	60,000	60.0	60.0
Lake Mabel Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	12/23	**	74,500	74.5	74.5
Dover Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	12/23	**	25,000	25.0	25.0
Solar Total [2,3]											**1,252,100**	**1,252**	**1,252**
											TOTAL	**5,983**	**6,433**

Notes:

* Limited by environmental permit.

** Undetermined.

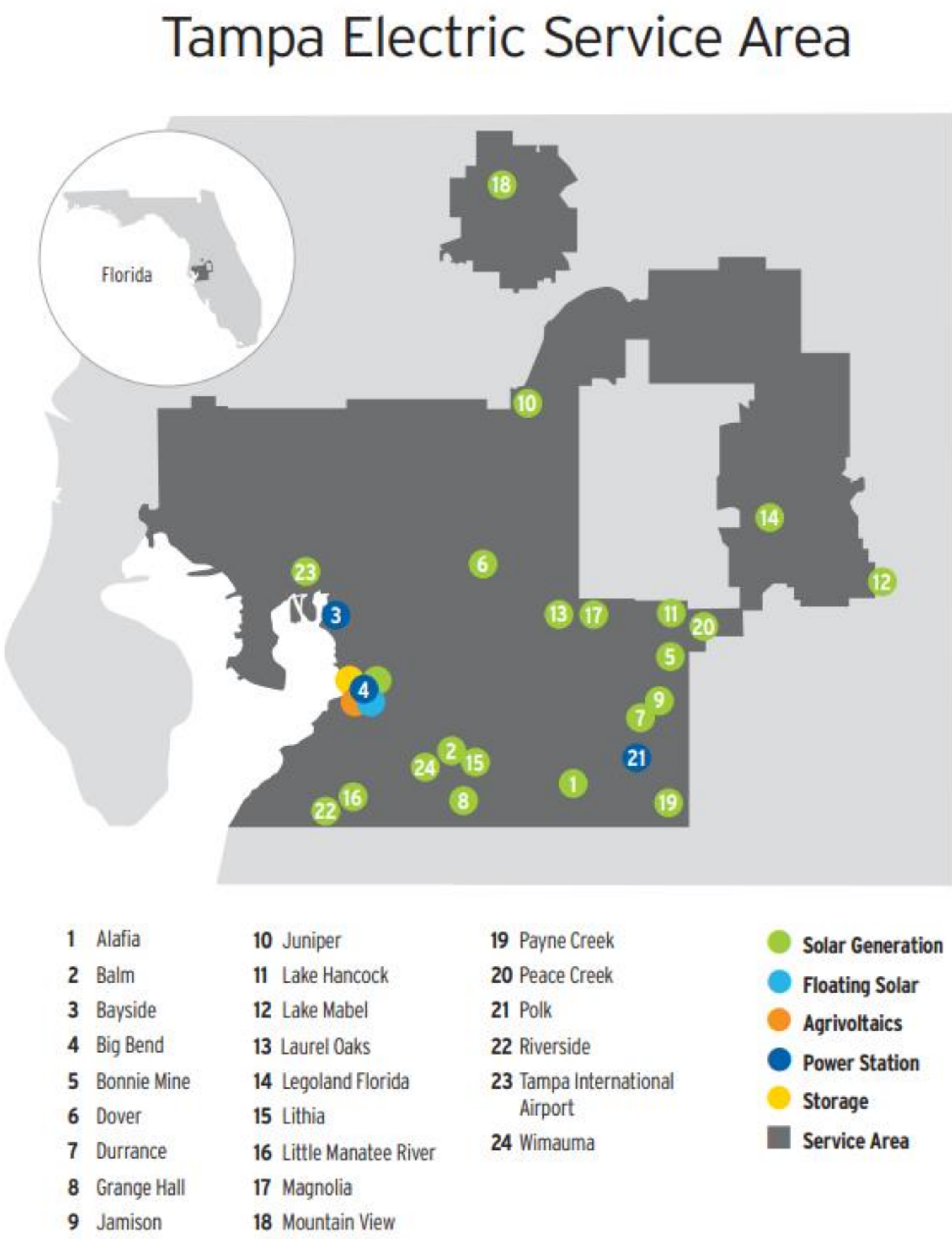
1 The 12.6 MW Big Bend Battery was integrated into the solar site at Big Bend in December 2019.

2 Rating for Solar units are nameplate.

3 Utility owned solar/battery less than 1 MW not included.

4 Big Bend 3 retired 4/23 with a Gen Max. nameplate capacity of 445,500 kW and a Summer and Winter Net Capacity of 395 MW and 400 MW respectively.

Figure I-I: Tampa Electric Service Area Map



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Chapter II

TAMPA ELECTRIC COMPANY FORECASTING METHODOLOGY

The customer, demand and energy forecasts are the foundation from which the IRP is developed. Recognizing their importance, TEC employs proven 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 methodologies and the major assumptions utilized in developing the 2024-2033 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the years 2024-2033.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2024-2033 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.

TEC's retail customer, demand and energy forecasts are the result of eight separate forecasting analyses:

1. Economic Analysis
2. Customer Multiregression Model
3. Energy Multiregression Model
4. Peak Demand Multiregression Model
5. Phosphate Demand and Energy Analysis
6. Customer-Owned Photovoltaic (PV)
7. Electric Vehicle Charging (EV)
8. Conservation, Load Management and Cogeneration Programs

The MetrixND models are the company's most sophisticated and primary load forecasting models. The phosphate demand and energy are forecasted separately and then combined in the final forecast, as well as the lighting forecast energy and effects of customer-owned photovoltaic (PV) and electric vehicle (EV) related energy and demand. Likewise, the effects of TEC's conservation, load management, and cogeneration programs are incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

1. Economic Analysis

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

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

2. Customer Multiregression Model

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

- ***Residential Customer Model (Equation #1):*** Customer projections are a function of regional population due to the strong correlation that exists between regional population and historical changes in service area customers.

- ***Commercial Customer Model:*** Total commercial customers include commercial customers plus construction service customers; therefore, two models are used to forecast total commercial customers:

    - The <u>Commercial Customer Model</u> ***(Equation #2)*** is a function of commercial employment and a time trend variable. An increase in employment signals growth in additional services, restaurants, and retail establishments.

    - Projections of permits in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the <u>Construction Service Model</u> ***(Equation #3)*** projects the number of customers as a function of new construction permits.

- ***Industrial Customer Model (Non-Phosphate):*** *Non-phosphate industrial customers include four rate classes modeled individually: General Service, General Service Demand, General Service Large Demand and Standby Large Demand.*

    - The <u>General Service Customer Model</u> ***(Equation #4)*** is a function of Hillsborough County commercial employment.

    - The <u>General Service Demand Customer Model</u> ***(Equation #5)*** is a function of Hillsborough County manufacturing employment.

    - The <u>General Service Large Demand Customer Model</u> ***(Equation #6)*** is a function of recent trends.

- The Standby Large Demand Customer Model ***(Equation #7)*** is a function of recent trends.

- ***Industrial Phosphate Customers:*** Customer counts seldom change within this industry; however, actual counts are tracked for any changes and phosphate accounts are individually surveyed annually to reflect any known future changes.

- ***Public Authority Customer Model:*** Customer projections are based on the recent growth trends in the governmental sector and are modeled individually for five rate classes: Residential Service, General Service, General Service Demand, General Service Large Demand and Standby Large Demand. ***(Equations #8 through #12)***

- ***Street & Highway Lighting Customers:*** Customer projections are based on recent growth trends in the sector and provided exogenously by the Lighting Growth department, subject matter experts who are familiar with industry dynamics and changing lighting technologies which can drive new customer growth.

3. Energy Multiregression Model

The energy multiregression forecasting model is also a twelve-equation model. All these equations represent average usage per customer (kWh/customer), except for the construction services which represent total energy (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 a Statistically Adjusted End-Use (SAE) framework. 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, as do econometric regression models.

- ***Residential Energy Model (Equation #1)****:* 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:

$$\textbf{HeatEquipIndex} = \sum_{Tech.} Weight \times \left(\frac{Saturation_{y} \;/\; Efficiency_{y}}{Saturation_{base\,y} \;/\; Efficiency_{base\,y}} \right)$$

$$\textbf{CoolEquipIndex} = \sum_{Tech.} Weight \times \left(\frac{Saturation_{y} \;/\; Efficiency_{y}}{Saturation_{base\,y} \;/\; Efficiency_{base\,y}} \right)$$

$$\textbf{OtherEquipIndex} = \sum_{Tech.} Weight \times \left(\frac{Saturation_{y} \;/\; Efficiency_{y}}{Saturation_{base\,y} \;/\; Efficiency_{base\,y}} \right)$$

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

$$\textbf{HeatUse}_{y,m} = \left(\frac{Price_{y,m}}{Price_{base\,y,m}}\right)^{-.10} \times \left(\frac{HH\ Income_{y,m}}{HH\ Income_{base\,y,m}}\right)^{.17} \times \left(\frac{HH\ Size_{y,m}}{HH\ Size_{base\,y,m}}\right)^{.15} \times \left(\frac{HDD_{y,m}}{Normal\ HDD}\right)$$

$$\textbf{CoolUse}_{y,m} = \left(\frac{Price_{y,m}}{Price_{base\,y,m}}\right)^{-.10} \times \left(\frac{HH\ Income_{y,m}}{HH\ Income_{base\,y,m}}\right)^{.17} \times \left(\frac{HH\ Size_{y,m}}{HH\ Size_{base\,y,m}}\right)^{.15} \times \left(\frac{CDD_{y,m}}{Normal\ CDD}\right)$$

$$\textbf{OtherUse}_{y,m} = \left(\frac{Price_{y,m}}{Price_{base\,y,m}}\right)^{-.10} \times \left(\frac{HH\ Income_{y,m}}{HH\ Income_{base\,y,m}}\right)^{.17} \times \left(\frac{HH\ Size_{y,m}}{HH\ Size_{base\,y,m}}\right)^{.15} \times \left(\frac{Billing\ Days_{y,m}}{Billing\ Days_{base\,y,m}}\right)$$

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

- ***Commercial Energy Model:*** total commercial energy sales include commercial sales plus construction service sales; therefore, two equations are used to forecast total commercial energy sales.
    - Commercial Energy Model ***(Equation #2)***: 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.

  - Construction Service Energy Model ***(Equation #3)***: This model is a subset of the total commercial sector and is a small percentage of the total commercial sector. Although small, it is still a component that must be included. A simple regression model is used with the drivers being construction service customer growth, projections of construction permits, along with the number of days billed, and cooling and heating degree-days.

- ***Industrial Energy Model (Non-Phosphate):*** *Non-phosphate industrial energy includes four rate classes modeled individually: General Service, General Service Demand, General Service Large Demand and Standby Large Demand.*

  - The General Service Energy Model ***(Equation #4)*** utilizes the same SAE model framework as the commercial energy model. The weather component is consistent with the residential and commercial models.

  - The General Service Demand Energy Model ***(Equation #5)*** is based on manufacturing output, the price of electricity in the industrial sector, cooling degree-days and number of days billed. Unlike the previous models discussed; heating load does not impact this sector.

  - The General Service Large Demand Energy Model ***(Equation #6)*** is based on cooling degree-days and seasonal trends.

  - The Standby Large Demand Energy Model ***(Equation #7)*** is based on cooling degree-days and seasonal trends.

- ***Public Authority Sector Energy Model:*** The governmental sector is modeled individually for five rate classes: Residential Service, General Service, General Service Demand, General Service Large Demand, and Standby Large Demand.

  - The Residential Service Energy Model ***(Equation #8)*** is based on the residential equipment saturation and efficiency assumptions used in the residential model.

  - The General Service Energy Model ***(Equation #9)*** 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.

  - The General Service Demand Energy Model ***(Equation #10)*** is a function of cooling and heating degree-days.

  - The General Service Large Demand Energy Model **(Equation #11)** is based on cooling degree-days.

  - The Standby Large Demand Energy Model ***(Equation #12)*** is based on seasonal trends.

- ***Street & Highway Lighting Sector Energy:*** Street and highway lighting is not weather sensitive; therefore, it is a simple calculation. Street and highway lighting energy consumption is a function of energy (kWh) ratings by fixture type times the number of projected lighting fixtures. This information is provided exogenously by the Lighting Growth department, subject matter experts who are familiar with industry dynamics and changing lighting technologies which can drive changes in energy projections. The street and highway lighting forecast reflects the impacts of the company's LED lighting program.

The twelve energy models described above, plus the incremental effects of customer-owned rooftop solar [PV], electric vehicle [EV] charging and conservation related energy, along with an exogenous lighting, and phosphate forecast, are added together to arrive at the total retail energy sales forecast. See sections 5 – 8 below for details. A line loss factor is applied to the energy sales forecast to produce the retail net energy for load forecast (RNEL).

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, and 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 industrial 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 based on the following: temperature at the time of the peak, 24-hour average on the day of the peak and the day prior to the peak. By incorporating the day prior to the peak, 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 and adjusted for the incremental effects of customer-owned PV, EV charging, and conservation related demand to arrive at the final projected peak demand.

5. Phosphate Demand and Energy Analysis

TEC phosphate customers are relatively few, which has allowed the company's Commercial and Industrial Business Development 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 phosphate customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecasts are based. Further input is provided by individual customer trend analysis and discussions with industry experts.

6. Customer-Owned Solar (PV)

Customer-owned solar forecasts are based on the historical number of PV installations and the average size of the PV systems installed in the service area. From this historical data, future penetration levels of PVs are based on assumptions used by the Energy Information Administration's (EIA) for the South Atlantic region. It is assumed Tampa Electric will no longer have to serve this portion of PV customers' load; therefore, the energy sales forecast is adjusted downward to incorporate the loss of this load.

7. Electric Vehicle (EV) Charging

The electric vehicle charging forecast process begins with an estimate of the number of EVs operating in Tampa Electric's service area. Future penetration levels of EVs are based on assumptions used by the Energy Information Administration's (EIA) for the South Atlantic region. The demand and energy consumption associated with EV charging is based on several assumptions including the average number of miles driven in a year, the weighted average battery size of seven common EV models sold within the service area and the number of charges per year.

8. 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 Demand Side Management (DSM) savings throughout the forecast horizon.

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

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

1. Defer expansion, particularly production plant construction.
2. Reduce marginal fuel cost by managing energy usage during higher fuel cost periods.
3. Provide customers with some ability to control energy usage and decrease energy costs.
4. Pursue the cost-effective accomplishment of the FPSC ten-year demand and energy conservation goals for the residential and commercial/industrial sectors.
5. Achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act (FEECA).

In 2023, Tampa Electric continued operating within the FPSC approved 2020-2029 DSM Plan which consists of one renewable program, one research and development program, 15 residential and 20 commercial DSM

Programs which support the approved FPSC goals which are reasonable, beneficial, and cost-effective to all customers as required by the FEECA. Also in 2023, the company continued the process with all the other FEECA utilities to start the development of the technical potential study which will support the 2025-2034 DSM Plan projected to be filed in the spring of 2024. The following is a list that briefly describes the company's DSM programs:

1. Energy Audits - a "how to" information and analysis guide for customers. Six types of audits are available to Tampa Electric 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. Energy and Renewable Education, Awareness and Agency Outreach - a program that provides opportunities for engaging and educating groups of customers, students on energy-efficiency and conservation in an organized setting and electric vehicles at participating high schools. Participants are provided with an energy savings kit which includes energy saving devices and supporting information appropriate for the audience.

5. Energy Star for New Multi-Family Residences - a rebate program that encourages the construction of new multi-family residences to meet the requirements to achieve the ENERGY STAR certified apartments and condominium label.

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. Energy Star Pool Pumps - a rebate program that encourages residential customers to install Energy Star rated pool pumps in existing homes.

8. Energy Star Thermostats - a rebate program that encourages residential customers to install Energy Star rated thermostats in existing homes.

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

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

11. Prime Time Plus – a program that reduces weather-sensitive loads through direct load control of residential customers HVAC, water heating and pool pumps. This program uses the company's advanced metering infrastructure ("AMI") system.

12. 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.

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

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 not sanctioned by other commercial programs.

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

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

19. Commercial Facility Energy Management System – a rebate program that encourages commercial and industrial customers to install high efficiency energy management systems.

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

21. Street and Outdoor Lighting Conversion – A program that converts Tampa Electric's metal halide and high-pressure sodium street and outdoor lighting to energy efficient light emitting diode (LED) technology to reduce energy consumption and Tampa Electric's peak demand. Tampa Electric will recover the remaining unamortized costs in rate base with the eligible non-LED luminaires. The company completed this conversion program in 2023.

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

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

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

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

26. Commercial Smart Thermostat - a rebate program that encourages commercial and industrial customers to install smart thermostats.

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

28. Variable Frequency Drive Control for Compressors - a rebate program that encourages commercial and industrial customers to install variable frequency drives on refrigerant or compressed air systems.

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

30. Integrated Renewable Energy System – a five-year pilot program to study and understand the potential opportunities and interactions of a fully integrated renewable energy system that contains a photovoltaic system, batteries, car charging and industrial truck charging.

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

The programs listed above were developed to meet FPSC demand and energy goals established in Docket No. 20190021-EG, Order No. PSC-2019-0509-FOF-EU, Issued November 26, 2019. The 2023 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

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

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

TABLE III-1
Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals
Savings at the Generator

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	12.3	2.6	473.1%	10.8	1.1	981.8%	21.2	1.8	1,177.8%
2016	7.7	4.1	187.8%	5.1	1.6	318.8%	13.2	3.5	377.1%
2017	6.9	5.2	132.7%	4.7	2.2	213.6%	14.9	4.8	310.4%
2018	8.0	6.5	123.0%	5.6	2.7	205.7%	17.1	6.1	280.3%
2019	8.3	7.6	108.8%	5.7	3.1	184.5%	16.8	6.9	243.2%
2020	3.5	7.6	45.5%	2.6	3.3	78.2%	8.9	7.4	120.3%
2021	4.5	8.0	55.8%	6.4	3.3	194.2%	16.4	7.7	213.1%
2022	9.5	7.4	127.8%	11.1	3.0	369.8%	30.4	6.9	441.0%
2023	10.3	6.8	151.2%	12.5	2.9	429.5%	29.6	6.3	469.9%
2024		6.1			2.5			5.5	

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	8.1	1.2	675.0%	11.7	1.7	688.2%	12.5	3.9	320.5%
2016	2.9	1.3	223.1%	4.4	2.5	176.0%	17.8	6.0	296.7%
2017	9.2	1.6	575.0%	10.4	2.7	385.2%	30.2	8.0	377.5%
2018	13.0	1.7	767.1%	15.0	3.3	453.6%	33.7	9.2	365.9%
2019	22.4	1.6	1401.9%	29.2	3.3	885.9%	74.6	9.9	753.4%
2020	10.4	1.7	612.5%	11.8	3.5	336.0%	26.1	10.3	253.3%
2021	4.7	1.9	246.2%	5.6	3.6	156.8%	20.4	10.4	196.1%
2022	7.1	1.9	376.0%	12.3	3.3	372.2%	26.6	10.2	261.2%
2023	7.2	1.8	398.1%	8.1	3.5	232.1%	30.3	9.9	305.6%
2024		1.7			3.2			9.6	

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	20.4	3.8	536.8%	22.5	2.8	803.6%	33.7	5.7	591.2%
2016	10.6	5.4	196.3%	9.5	4.1	231.7%	31.0	9.5	326.3%
2017	16.1	6.8	236.8%	15.1	4.9	308.2%	45.1	12.8	352.3%
2018	21.0	8.2	256.5%	20.5	6.0	342.1%	50.8	15.3	331.8%
2019	30.7	9.2	333.7%	35.0	6.4	546.2%	91.4	16.8	543.9%
2020	13.9	9.3	149.1%	14.3	6.8	210.9%	35.0	17.7	197.7%
2021	9.1	9.9	92.3%	12.1	6.9	174.7%	36.8	18.1	203.3%
2022	16.6	9.3	178.5%	23.4	6.3	371.0%	57.1	17.1	333.8%
2023	17.4	8.6	202.9%	20.6	6.4	321.6%	59.9	16.2	369.5%
2024		7.8			5.7			15.1	

BASE CASE FORECAST ASSUMPTIONS

RETAIL LOAD

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

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

1. Population and Households

Florida and Hillsborough County population forecasts are the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Moody's Analytics supply population projections for Hillsborough County and Florida comparisons. BEBR's population growth for Hillsborough County was used to project future growth patterns in residential customers from 2024-2033. The average annual population growth rate is expected to be 1.5%.

2. Commercial, Industrial and Governmental Employment

Commercial, industrial, and governmental employment assumptions are utilized in computing the number of customers in their respective sectors. Over the next ten years (2024-2033), employment is assumed to rise at a 1.2% average annual rate within Hillsborough County. Moody's Analytics supplies employment projections for the non-residential models.

3. Commercial, Industrial and Governmental Output

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Output for the entire employment sector within Hillsborough County is assumed to rise at a 3.4% average annual rate from 2024-2033. 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 2024-2033, real household income for Hillsborough County is expected to increase at a 1.3% 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 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. 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. Monte Carlo simulations are performed to estimate weather probabilities.

HIGH AND LOW SCENARIO FORECAST 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 2024-2033, retail energy sales are projected to rise at a 0.9% annual rate. The primary contributor to growth is the residential class increasing at an annual rate of 1.2%.

2. Wholesale Energy

TEC has no scheduled firm wholesale power sales currently.

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 2024-2033, TEC's base retail firm peak demand is expected to increase at an average annual rate of 0.9% in the summer and 1.2% in the winter.

Chapter III

INTEGRATED RESOURCE PLANNING PROCESSES

TEC's IRP process is designed to evaluate demand-side and supply-side resources on a comparable and consistent basis to satisfy future demand and energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders.

The process incorporates a reliability analysis to determine timing of future needs and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. Initially, a demand and energy forecast is developed which excludes incremental energy efficiency and conservation programs. This forecast is used to identify the basis for the next potential avoided unit(s), and becomes the baseline used to perform a comprehensive cost effectiveness analysis of these programs based on the following Commission approved 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 also used in this analysis. All measures that pass the RIM and PCT tests in the energy efficiency and demand response analysis are considered for utility program adoption.

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

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

Generating supply side 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 system requirements.

TEC uses a long- term planning computer model developed by Energy Exemplar, PLEXOS, to evaluate supply-side resources. PLEXOS utilizes a mixed integer linear program (MILP) to develop an estimate of the timing and type of supply-side resources for generation additions that would economically meet the system demand and energy requirements. The objective function of the MILP is to compare all feasible combinations of generating unit additions, satisfy the specified reliability criteria, and determine the schedule and addition with the lowest total system cost.

Detailed cost analyses for each of the top ranked resource plans are performed using the Energy Exemplar's PLEXOS production cost model. The capital expenditures, including interconnection costs and incremental fuel transportation 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 cumulative present value of revenue requirements for each alternative plan.

The result of the IRP process provides Tampa Electric's customers with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment, while positioning Tampa Electric for a lower carbon future. To meet the expected system demand and energy requirements and cost-effectively maintain system reliability, the company's expansion plan includes the following:

- Enhancements of existing assets
- Completion of solar PV through 2023, in accordance with the 2021 Rate Case Settlement
- Additional future utility-scale solar, battery storage, and reciprocating engines beyond 2024 until the end of the study period

The Bayside Unit 1 advanced hardware improvements to its existing CTs was completed and placed in service in 2023. Bayside Unit 2 advanced hardware improvements to its existing CTs will be operational in 2024.

The remainder of the expansion plan presented in this Ten-Year Site Plan will meet growing customer needs with the addition of energy resources distributed throughout our territory. In addition to enhancements to the existing assets and the utility-scale solar, battery storage and reciprocating engines will be added to meet customer demand growth and provide operational flexibility and system resiliency to better serve our customers. The detailed expansion plan is shown in Schedule 8.1.

TEC will continue to assess competitive purchase power agreements and DSM programs that may replace or delay the scheduled units. Such optimizations must achieve the overall objective of providing reliable power in a cost-effective manner.

FINANCIAL ASSUMPTIONS

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

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

- Depreciation represents the annual cost to amortize the total original investment in a plant over its useful life less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the TYSP represents the average expected life for that type of asset.

FUEL FORECAST

TEC forecasts base case fuel commodity prices for natural gas, coal, and oil by analyzing current market prices and price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, S&P Global, U.S. Energy Information Administration, and Coaldesk, LLC Publications. For natural gas, coal and oil prices, the company produces both high and low fuel price projections, which represent alternative forecasts to the company's base case outlook.

TEC RENEWABLE RESOURCES AND STORAGE TECHNOLOGY INITIATIVES

1. Renewable Energy Initiatives and Customer Programs

In September 2017, TEC announced plans to build 600 MW_{AC} of new solar PV generating capacity from 2018 through January 2021, which is enough electricity to power more than 100,000 homes. The actual design and completion of these projects resulted in 632 MW_{AC} and combined with 23 MW_{AC} from three smaller projects built prior to 2018, created a total of 655 MW_{AC} of solar capacity. In February 2020, the Company announced plans to build an additional 597 MW_{AC} of new cost-effective, utility-scale solar PV generating capacity from 2021 through the end of 2023 for a total of 1,252 MW_{AC}. By the end of 2024, Tampa Electric will have about 1,350 MW_{AC} of solar power – enough energy to power more than 214,000 homes – or approximately 13 percent of TEC's energy produced by the sun.

The company's proposed solar expansion helps lower electricity costs. These cost-effective projects also help serve increased customer load while reducing the impact of fuel price fluctuations on the customers' bill due to the zero-fuel cost generation. The additional utility-scale solar will help moderate fuel price volatility, increase fuel diversity, reduce reliance on natural gas, and has little to no water requirements for operations. In addition, with the passage of the Inflation Reduction Act, the federal government is providing additional tax incentives which will also benefit customers.

Beyond 2024 there is an additional 1,489 MW_{AC} of solar PV generating capacity shown in this TYSP that is in the planning and analysis phase and requires further development. In sum, TEC would have over 2,800 MW_{AC} of solar capacity by the end of the study horizon, which means approximately 27 percent of our energy will come from the sun.

Since 2006, TEC implemented 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 feature to the program which allows residential, commercial, and industrial customers the opportunity to purchase renewable energy in one-time blocks to power a specific event. This enables a family, business, or venue to make a statement about their commitment to the environment and to renewable energy. Through December 2023, TEC's Renewable Energy Program has 1,082 customers purchasing over 1,924 blocks of renewable energy each month and there have been over 5,600 one-time blocks purchased since program inception.

The company's renewable generation portfolio is a mix of various technologies and renewable generation sources, including both large utility scale solar PV sites and smaller, company-owned community sited PV arrays that provide ample solar energy for the Renewable Energy Block Program. The smaller, community-sited PV arrays are currently installed at Middleton High school, the Manatee Viewing Center, Zoo Tampa at Lowry Park, the Florida Aquarium, LEGOLAND Florida's Imagination Zone, the Museum of Science and Industry (MOSI), and Meachum Urban Farm. The newest array is located at an organic farm and store open to the public in downtown Tampa, featuring solar with battery storage and a charging station for visitor use. The Renewable Energy Program installations are strategically located throughout the community and are designed to educate students and the public on the benefits of renewable energy. Educational signage touts the advantages of solar energy and interactive displays provide hands-on experience to engage visitors' interest in clean, renewable technologies.

The Florida Conservation and Technology Center (FCTC) located south of Big Bend Station is a collaborative partnership with the Florida Aquarium and Florida Fish & Wildlife to develop and educate students and the public on water and energy conservation technologies, marine science development and clean energy demonstrations. The FCTC site includes the TEC Manatee Viewing Center, the Center for Conservation, and the TEC Clean Energy Center (CEC). The CEC has a flexible rooftop adhesive PV array, a dual axis tracking PV Smart Flower array, and a fixed tilt solar canopy array. The FCTC also includes a vertical axis Be-Wind wind turbine, a vanadium flow battery and a supercapacitor based energy storage system. A 1 MW_{AC} floating solar pilot project at FCTC began operations in 2022. It integrates solar panels onto floats and will analyze the benefits of bi-facial solar panels capabilities to increase the output created from reflected light onto the reverse side of the solar panels. The data collected and lessons learned will inform future applications over open water reservoirs and demonstrate that floating solar has the potential to decrease the evaporation of water. A 1 MW_{AC} agrivoltaics pilot project at FCTC was also completed in 2022. The project was designed to combine renewable energy with agriculture by positioning elevated solar panels in wider rows with plants or crops planted between the rows of solar panels. This will provide farmable acreage to balance the community attrition of acreage due to development. Agrivoltaics applications have the potential to lower the operating costs of large utility scale solar sites by sharing viable land with agricultural interests.

By Order No. PSC-2019-0215-TRF-EI, the Commission approved Tampa Electric Company's (TECO or utility) Shared Solar Tariff (SSR-1 tariff). The SSR-1 tariff provides residential and commercial customers with the option to purchase energy produced from a TECO-owned solar generation facility to replace all or a portion of their monthly energy consumption. Participants are charged a Shared Solar Charge of $0.063 per kilowatt-hour while the fuel kWh is removed for the subscribed portion. The SSR-1 tariff became effective on June 25, 2019, after TECO completed programming its billing system to administer the SSR-1 tariff. Tampa Electric Company launched the Sun Select program on June 26, 2019, making 17.5 MW_{AC} of solar generation available to its customers via the SSR-1 tariff.

2. Storage Technology Initiatives

Battery storage projects will help maintain the required winter capacity reserve margin as peak load grows with increased customers. Additionally, battery storage provides fuel savings for customers through energy arbitrage, where energy is stored during off-peak hours when electricity prices are cheapest and used during on-peak hours when electricity prices are highest. Other added benefits include the potential deferral or avoidance of future transmission and distribution investments by eliminating an otherwise necessary upgrade by locating an energy source close to a high load area.

In 2018, Tampa Electric began interconnecting customer-owned battery storage. As of December 31, 2023, there are 1,083 customers interconnected with 9.90 MW DC storage capacity.

3. Electric Vehicle Initiatives

The upward trajectory of customer adoption of Electric Vehicles (EV) continues, and this trend is expected to persist into the foreseeable future. Florida continually ranks second in the nation for the number of EVs sold, and TEC is forecasting a nearly 30% average annual growth rate in the number of EVs within our service area through 2030. Given the ongoing enhancements in battery technology and cost efficiencies, increased access to public charging infrastructure, and greater consumer choice in the types of EVs offered by major automakers, forecasts show EV adoption will continue to grow.

Most recently, in 2021, the FPSC approved TEC's Drive Smart℠ EV charging pilot, which allows for the installation of up to 200 Level 2 (240V) and up to four Direct Current Fast Charging (DCFC) stations across the service territory. The 4-year pilot will help to increase driver confidence by expanding access to EV charging, while also providing valuable data to support proper grid planning. The pilot has seen significant interest from customers with nearly 750 ports being applied for. In 2020, TEC received FPSC approval for a variance to CIAC Rule No. 25-6.064, F.A.C. when primary line extensions are required to serve high-power DCFC locations. Through this variance, TEC can extend the revenue period used in determining customer CIAC, from 5 years to 10 years. By doing so, the economics for charging station developers should significantly improve, particularly as charging needs expand to more rural areas and underserved communities. To educate future Electric Vehicle (EV) drivers, TEC introduced a high school driver education program as an enhancement of the company's ongoing Energy Education and Awareness conservation program. TEC not only provided funding for the EVs, but also installed the necessary EV chargers and helped to develop curriculum used in the classrooms.

Through these activities, as well as increased customer engagement, TEC is learning valuable information to support the needs of specific market segments, particularly multi-family residential properties and commercial fleets. The high concentration of EVs at these locations requires extensive planning for both the customer and utility infrastructure needed to provide adequate charging while minimizing grid impacts. As EV adoption continues to increase, smart grid enhancements, smart charging infrastructure and innovative customer programs will be necessary to help manage the potential effects of EV charging on our grid, in a way that benefits all TEC customers.

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

1. Reserve Margin

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

2. Winter Reliability Assessment

Tampa Electric Company's current and expected resources meet operating reserve requirements under normal peak demand scenarios. The reserve margin provides operating flexibility in the case of unplanned outages and deviations to load from colder than normal (or hotter than normal) weather. However, temperatures that vary significantly from those used to prepare this plan would result in the need to employ operating mitigation under these extreme conditions. These mitigations could include changes to unit dispatch to enhance reliability, switching to alternate fuels, making full use of demand response, pursuing purchase power agreements, and potentially interrupting customers to maintain grid stability. The company has reviewed and updated its freeze protection plans for each of its generation stations and implemented measures to mitigate equipment failure during these extreme temperatures. Refer to schedule 7.2.1 to see how a 2-degree change in temperatures can impact winter reserve margins.

SUPPLY-SIDE RESOURCES PROCUREMENT PROCESS

TEC uses wholesale power market opportunities to enhance and optimize its system. Prospective suppliers of supply-side resources are identified in accordance with established policies and procedures. Competitive bid evaluations are used in developing award recommendations to management. Fuel, fuel transportation, transmission availability, transmission cost, environmental requirements, ancillary services, and balancing requirements are considered as part of evaluating future supply-side resources.

This process allows for future supply-side resources to be supplied from self-build, purchased power, or asset purchases. Consistent with company practice, bidders are encouraged to propose incentive arrangements that promote development and implementation of cost savings and process-improvement recommendations.

TRANSMISSION PLANNING - CONSTRAINTS AND IMPACTS

The TEC transmission system supports the reliable delivery of required capacity and energy to TEC's retail and wholesale customers. Transmission Planning studies are performed annually to evaluate the performance of the TEC transmission system with the results of the studies varying due to refinements in load projections, planning criteria, generation plans and operating flexibility. This involves the use of steady-state load flow, short circuit and transient stability programs to model various contingency situations, 3-Phase Fault and Single Line-Ground Fault analysis that may occur to determine if the TEC transmission system meets the reliability criteria. Simulations of normal system conditions, as well as single and select multiple contingency events, are performed during system peak and off-peak load levels, and summer and/or winter conditions.

Based on existing studies (ex: internal expansion, joint utility, operating, Florida Reliability Coordinating Council (FRCC) Long Range Study, FRCC Planning and Extreme Events Stability Analysis, FRCC Summer Assessment, FRCC Winter Assessment and other miscellaneous studies) and TEC's current transmission construction program, TEC anticipates no transmission constraints that violate the criteria as described in the Transmission Planning Reliability Criteria section of this document.

TRANSMISSION PLANNING RELIABILITY CRITERIA

1. Transmission

TEC developed the transmission planning reliability criteria, as described in the FERC Form 715 filing, to assess and test the strength and limits of the transmission system, while meeting the load responsibility and being able to move bulk power between and among other electric systems. TEC has adopted the transmission planning criteria outlined in the FRCC's *FRCC Regional Transmission Planning Process*. The FRCC's transmission planning criteria are consistent with the North American Electric Reliability Corporation (NERC) Reliability Standards.

In general, the NERC Reliability Standards state the transmission system will remain stable, within the applicable thermal and voltage rating limits, without cascading outages, under normal, single and select multiple contingency conditions. In addition to the FRCC criteria, TEC utilizes company-specific planning criteria for normal system operation and contingency operation, along with a Facility Rating Methodology and Facility Interconnection Requirements document available at https://www.oasis.oati.com/TEC/index.html.

The transmission planning reliability criteria are used as guidelines for proposing transmission system expansion and/or improvement projects, however they are not absolute rules for system expansion. These criteria are used to alert planners of potential transmission system capacity limitations. Engineering analysis is used in all stages of the planning process to weigh the impact of system deficiencies, the likelihood of the triggering contingency, and the viability of any operating options. Only by carefully researching each potential planning criteria violation can a final evaluation of available transmission capacity be made.

2. Available Transmission Transfer Capability (ATC) Criteria

TEC adheres to the ATC calculation methodology described in the Attachment C of the Tampa Electric Company *Open Access Transmission Tariff FERC Electric Tariff*, Fourth Revised Volume No. 4 document, accessible at https://www.oasis.oati.com/woa/docs/TEC/TECdocs/Tariff Fourth Revised Volume No. 4 effective 5-1-23.pdf as well as the principles contained in the NERC Reliability Standards relating to ATC calculations. Members of the FRCC, including TEC, have formed the Florida Transmission Capability Determination Group in an effort to provide ATC values to the regional electric market that are transparent, coordinated, timely and accurate.

TRANSMISSION SYSTEM PLANNING ASSESSMENT PRACTICES

TEC's transmission system planning assessment practices are developed according to the TEC and NERC Reliability Standards to ensure a reliable system is planned that demonstrates adequacy within TEC's footprint to meet present and future system needs. The Reliability Standards require that the TEC transmission system be planned such that it will remain stable within the applicable facility ratings and voltage rating limits and without cascading outages under normal system conditions, as well as single and select multiple contingency events.

TEC performs transmission studies independently, collaboratively with other utilities, and as part of the FRCC to determine if the system meets the criteria. The studies involve the use of steady-state power flows, transient stability analyses, short circuit assessments and various other assessments to ensure adequate system performance.

1. Base Case Operating Conditions

The TEC transmission system can support peak and off-peak system load levels while meeting the criteria as described in the Transmission Planning Reliability Criteria section of this document.

2. Single Contingency Planning Criteria

The TEC transmission system is designed to support any single event outage of a transmission circuit, autotransformer, generator, or shunt device (including FRCC studies of Category P1 and P2-1 events) at a variety of load levels while meeting the criteria as described in the Transmission Planning Reliability Criteria section of this document.

3. Multiple Contingency Planning Criteria

Select double contingencies (including FRCC studies of Category P2-2 through P7 events) involving two or more Bulk Electric System (BES) transmission system elements out of service are analyzed at a variety of load levels. The TEC transmission system is designed such that double contingencies meet the criteria as described in the Transmission Planning Reliability Standards Criteria section of this document.

4. Transmission Construction and Upgrade Plans

A specific list of the proposed directly associated transmission construction projects corresponding with the proposed generating facilities can be found in Chapter V, Schedule 10. This list represents the latest BES transmission construction related to the generation expansion on Schedule 8.1 and 9. However, due to the timing of this document in relationship to the company's internal planning schedule, this plan may change in the future. The current transmission construction and upgrade plan for the planning horizon does not require any electric utility system lines to be certified under the Transmission Line Siting Act (403.52-403.536, F.S.).

ENERGY EFFICIENCY, CONSERVATION, AND ENERGY SAVINGS DURABILITY

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

- 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.
- Billing energy usage and demand analysis of participants in certain energy efficiency and conservation programs as compared to control groups.
- Analysis of DOE2 modeling of various program participants.
- End-use monitoring and evaluation of projects and programs.
- Specific metering of loads under control to determine the actual demand and energy savings in commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response.

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

Chapter IV

FORECAST OF ELECTRIC POWER, DEMAND AND ENERGY CONSUMPTION

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

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

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

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

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

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

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

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

Schedule 5: History and Forecast of Fuel Requirements

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

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

Schedule 2.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
	1,301,887	2.6	8,656	623,846	13,875	6,142	72,647	84,548
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
2016	1,352,797	2.6	9,187	646,221	14,217	6,310	74,313	84,911
2017	1,379,302	2.6	9,029	659,387	13,693	6,362	74,998	84,830
2018	1,408,864	2.6	9,418	670,517	14,046	6,266	74,895	83,664
2019	1,444,870	2.6	9,584	685,122	13,989	6,239	76,038	82,057
2020	1,459,762	2.6	10,122	698,493	14,491	6,058	76,790	78,890
2021	1,490,374	2.6	9,941	713,135	13,940	6,144	78,115	78,653
2022	1,520,529	2.6	10,109	729,334	13,861	6,300	79,610	79,131
2023	1,541,531	2.6	10,307	742,575	13,880	6,462	80,622	80,154
2024	1,569,983	2.6	10,200	755,744	13,497	6,289	81,520	77,145
2025	1,597,332	2.5	10,299	768,913	13,395	6,351	82,465	77,013
2026	1,624,239	2.5	10,413	781,870	13,318	6,415	83,413	76,907
2027	1,650,693	2.5	10,534	794,608	13,257	6,470	84,369	76,687
2028	1,676,455	2.5	10,662	807,013	13,212	6,524	85,342	76,451
2029	1,701,455	2.5	10,801	819,051	13,187	6,579	86,323	76,218
2030	1,725,605	2.5	10,948	830,679	13,179	6,634	87,304	75,982
2031	1,748,484	2.5	11,096	841,697	13,183	6,691	88,287	75,792
2032	1,770,488	2.5	11,249	852,292	13,198	6,752	89,270	75,641
2033	1,791,686	2.4	11,403	862,499	13,221	6,813	90,256	75,484

Notes:
December 31, 2023 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2024	1,585,472	2.6	10,261	759,455	13,511	6,292	81,539	77,164
2025	1,621,017	2.6	10,421	776,487	13,421	6,356	82,504	77,039
2026	1,656,429	2.6	10,598	793,455	13,357	6,422	83,472	76,942
2027	1,691,690	2.6	10,785	810,351	13,309	6,480	84,447	76,729
2028	1,726,550	2.6	10,982	827,055	13,278	6,536	85,443	76,499
2029	1,760,929	2.6	11,191	843,528	13,267	6,594	86,445	76,274
2030	1,794,728	2.6	11,410	859,723	13,272	6,650	87,449	76,046
2031	1,827,498	2.6	11,633	875,425	13,289	6,711	88,455	75,864
2032	1,859,633	2.6	11,863	890,823	13,317	6,774	89,462	75,719
2033	1,891,196	2.6	12,096	905,947	13,352	6,837	90,473	75,570

Notes:

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

Values shown may be affected due to rounding.

Schedule 2.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural and Residential			Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2024	1,554,570	2.5	10,140	752,032	13,483	6,286	81,502	77,127
2025	1,573,878	2.5	10,178	761,375	13,368	6,346	82,428	76,985
2026	1,592,521	2.5	10,229	770,397	13,278	6,408	83,356	76,873
2027	1,610,496	2.4	10,287	779,095	13,204	6,460	84,291	76,645
2028	1,627,578	2.4	10,350	787,362	13,146	6,513	85,244	76,402
2029	1,643,710	2.4	10,423	795,168	13,107	6,565	86,203	76,162
2030	1,658,822	2.4	10,502	802,481	13,086	6,617	87,163	75,919
2031	1,672,522	2.4	10,581	809,111	13,077	6,673	88,124	75,722
2032	1,685,208	2.3	10,663	815,249	13,080	6,731	89,085	75,562
2033	1,696,958	2.3	10,746	820,935	13,090	6,789	90,048	75,398

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
2014	1,901	1,572	1,208,831	0	75	1,752	18,526
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	2,024	1,608	1,259,094	0	0	1,771	19,186
2018	2,014	1,588	1,268,262	0	0	1,933	19,631
2019	2,021	1,516	1,332,913	0	0	1,939	19,783
2020	1,891	1,408	1,342,642	0	0	1,883	19,954
2021	2,122	1,382	1,535,835	0	0	1,886	20,093
2022	2,111	1,357	1,556,126	0	0	1,947	20,467
2023	2,082	1,330	1,565,053	0	0	1,939	20,791
2024	1,856	1,327	1,398,511	0	0	1,970	20,315
2025	1,837	1,325	1,386,481	0	0	1,979	20,466
2026	1,834	1,323	1,386,313	0	0	1,989	20,651
2027	1,833	1,322	1,387,137	0	0	1,998	20,835
2028	1,833	1,320	1,388,348	0	0	2,008	21,027
2029	1,832	1,319	1,389,525	0	0	2,017	21,229
2030	1,831	1,317	1,389,863	0	0	2,026	21,438
2031	1,830	1,316	1,390,405	0	0	2,036	21,653
2032	1,829	1,315	1,390,860	0	0	2,045	21,875
2033	1,828	1,314	1,391,549	0	0	2,055	22,098

Notes:
December 31, 2023 Status
*Average of end-of-month customers for the calendar year.
**Sales shown for Street and Highway Lighting from 2017 forward are now included with Other Sales to Public Authorities.
Values shown may be affected due to rounding.

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
			Average KWH Consumption	Railroads and Railways	Street & Highway Lighting	Other Sales to Public Authorities	Total Sales to Ultimate Consumers
Year	**GWH**	**Customers***	**Per Customer**	**GWH**	**GWH ****	**GWH**	**GWH**
2024	1,856	1,327	1,398,711	0	0	1,970	20,379
2025	1,837	1,325	1,386,061	0	0	1,979	20,593
2026	1,834	1,323	1,386,195	0	0	1,989	20,844
2027	1,833	1,322	1,386,648	0	0	1,998	21,096
2028	1,833	1,320	1,388,487	0	0	2,008	21,359
2029	1,832	1,319	1,389,182	0	0	2,017	21,634
2030	1,831	1,317	1,390,211	0	0	2,027	21,918
2031	1,830	1,316	1,390,421	0	0	2,036	22,209
2032	1,829	1,315	1,390,665	0	0	2,045	22,511
2033	1,828	1,314	1,391,083	0	0	2,055	22,816

Notes:

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

**Sales for Street and Highway Lighting from 2017 forward are now included with Other Sales to Public Authorities.

Values shown may be affected due to rounding.

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				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
2024	1,856	1,327	1,398,711	0	0	1,970	20,251
2025	1,837	1,325	1,386,061	0	0	1,979	20,340
2026	1,834	1,323	1,386,195	0	0	1,989	20,460
2027	1,833	1,322	1,386,648	0	0	1,998	20,579
2028	1,833	1,320	1,388,487	0	0	2,007	20,703
2029	1,832	1,319	1,389,182	0	0	2,017	20,837
2030	1,831	1,317	1,390,211	0	0	2,026	20,976
2031	1,830	1,316	1,390,421	0	0	2,035	21,119
2032	1,829	1,315	1,390,665	0	0	2,045	21,268
2033	1,828	1,314	1,391,083	0	0	2,054	21,417

Notes:

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

**Sales for Street and Highway Lighting from 2017 forward are now included with Other Sales to Public Authorities.

Values shown may be affected due to rounding.

Schedule 2.3

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

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
2014	0	789	19,315	8,095	706,161
2015	0	1,098	20,105	8,168	718,713
2016	9	930	20,173	8,353	730,503
2017	2	1,110	20,298	8,698	744,690
2018	0	1,031	20,662	9,254	756,254
2019	0	986	20,770	9,283	771,960
2020	0	1,101	21,055	9,356	786,047
2021	0	940	21,033	9,418	802,049
2022	0	1,105	21,572	9,466	819,766
2023	0	976	21,767	9,616	834,144
2024	0	1,040	21,355	9,668	848,259
2025	0	1,047	21,513	9,740	862,443
2026	0	1,056	21,706	9,810	876,416
2027	0	1,065	21,900	9,879	890,177
2028	0	1,074	22,100	9,947	903,622
2029	0	1,083	22,313	10,015	916,707
2030	0	1,094	22,532	10,082	929,383
2031	0	1,104	22,757	10,149	941,449
2032	0	1,115	22,990	10,217	953,093
2033	0	1,126	23,224	10,284	964,353

Notes:
December 31, 2023 Status
*Includes sales to St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
RCID contract from 2016 to 2017.
**Utility Use and Losses include accrued sales.
***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
****Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.3

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

(1) Year	(2) Sales for Resale GWH	(3) Utility Use * & Losses GWH	(4) Net Energy ** for Load GWH	(5) Other *** Customers	(6) Total *** Customers
2024	0	1,043	21,422	9,668	851,989
2025	0	1,054	21,647	9,740	870,056
2026	0	1,065	21,909	9,810	888,060
2027	0	1,078	22,174	9,879	905,999
2028	0	1,090	22,449	9,947	923,765
2029	0	1,104	22,738	10,015	941,307
2030	0	1,118	23,036	10,082	958,571
2031	0	1,133	23,342	10,149	975,345
2032	0	1,147	23,658	10,217	991,817
2033	0	1,163	23,979	10,284	1,008,018

Notes:

*Utility Use and Losses include accrued sales.

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

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

Values shown may be affected due to rounding.

Schedule 2.3

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

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWH	Utility Use * & Losses GWH	Net Energy ** for Load GWH	Other *** Customers	Total *** Customers
2024	0	1,037	21,288	9,668	844,529
2025	0	1,040	21,380	9,740	854,868
2026	0	1,046	21,506	9,810	864,886
2027	0	1,051	21,630	9,879	874,587
2028	0	1,057	21,760	9,947	883,873
2029	0	1,063	21,900	10,015	892,705
2030	0	1,070	22,046	10,082	901,043
2031	0	1,076	22,195	10,149	908,700
2032	0	1,083	22,351	10,217	915,866
2033	0	1,091	22,508	10,284	922,581

Notes:

*Utility Use and Losses include accrued sales.
**Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
***Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 3.1

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

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation***	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2014	4,275	0	4,275	170	36	132	96	84	3,757
2015	4,248	0	4,248	111	21	142	102	88	3,784
2016	4,401	15	4,386	138	0	149	101	92	3,907
2017	4,372	5	4,367	110	0	154	100	98	3,905
2018	4,289	0	4,289	125	0	159	101	106	3,798
2019	4,591	0	4,591	122	0	165	101	125	4,079
2020	4,573	0	4,573	113	0	169	104	135	4,053
2021	4,713	0	4,713	187	0	174	105	139	4,108
2022	4,772	0	4,772	204	0	183	106	148	4,131
2023	5,017	0	5,017	178	0	194	106	153	4,385
2024	4,762	0	4,762	135	0	211	106	166	4,143
2025	4,823	0	4,823	133	0	228	106	174	4,182
2026	4,890	0	4,890	133	0	247	106	182	4,222
2027	4,959	0	4,959	133	0	268	107	190	4,261
2028	5,029	0	5,029	133	0	290	107	198	4,302
2029	5,101	0	5,101	134	0	312	107	205	4,343
2030	5,173	0	5,173	134	0	333	107	213	4,385
2031	5,244	0	5,244	134	0	355	107	221	4,427
2032	5,316	0	5,316	134	0	377	107	229	4,469
2033	5,387	0	5,387	134	0	399	107	237	4,511

Notes:
December 31, 2023 Status
2016, 2018, 2020, 2022 and 2023 Net Firm Demand is not coincident with system peak.
Notes prior to 2024
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
***Includes Energy Planner program.
Values shown may be affected due to rounding.

Schedule 3.1

Forecast of Summer Peak Demand (MW)
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale	Retail *	Interruptible	Residential Load Management	Residential Conservation**	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2024	4,778	0	4,778	135	0	211	106	166	4,159
2025	4,856	0	4,856	133	0	228	106	174	4,215
2026	4,941	0	4,941	133	0	247	106	182	4,272
2027	5,028	0	5,028	133	0	268	107	190	4,330
2028	5,116	0	5,116	133	0	290	107	198	4,389
2029	5,209	0	5,209	134	0	312	107	205	4,451
2030	5,299	0	5,299	134	0	333	107	213	4,512
2031	5,392	0	5,392	134	0	355	107	221	4,575
2032	5,484	0	5,484	134	0	377	107	229	4,637
2033	5,578	0	5,578	134	0	399	107	237	4,701

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

Schedule 3.1

Forecast of Summer Peak Demand (MW)
Low Case

(1) Year	(2) Total *	(3) Wholesale	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation**	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2024	4,746	0	4,746	135	0	211	106	166	4,127
2025	4,790	0	4,790	133	0	228	106	174	4,149
2026	4,840	0	4,840	133	0	247	106	182	4,171
2027	4,892	0	4,892	133	0	268	107	190	4,194
2028	4,943	0	4,943	133	0	290	107	198	4,216
2029	4,998	0	4,998	134	0	312	107	205	4,240
2030	5,050	0	5,050	134	0	333	107	213	4,263
2031	5,103	0	5,103	134	0	355	107	221	4,286
2032	5,154	0	5,154	134	0	377	107	229	4,307
2033	5,207	0	5,207	134	0	399	107	237	4,330

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

Schedule 3.2

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

(1)	(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**
2013/14	3,880	0	3,880	61	64	512	100	64	3,079
2014/15	4,202	0	4,202	79	47	521	99	65	3,390
2015/16	4,034	0	4,034	145	21	533	98	67	3,171
2016/17	3,748	0	3,748	137	0	541	95	70	2,905
2017/18	4,670	0	4,670	66	0	548	96	77	3,883
2018/19	3,913	0	3,913	104	0	556	95	88	3,071
2019/20	4,238	0	4,238	140	0	564	98	99	3,336
2020/21	4,151	0	4,151	132	0	568	102	103	3,247
2021/22	4,414	0	4,414	158	0	572	104	108	3,473
2022/23	4,396	0	4,396	217	0	582	105	113	3,380
2023/24	5,229	0	5,229	116	0	596	105	120	4,292
2024/25	5,302	0	5,302	115	0	610	106	126	4,345
2025/26	5,383	0	5,383	115	0	626	106	132	4,404
2026/27	5,463	0	5,463	115	0	643	107	138	4,461
2027/28	5,544	0	5,544	115	0	661	107	143	4,517
2028/29	5,624	0	5,624	115	0	680	108	149	4,572
2029/30	5,703	0	5,703	115	0	699	109	155	4,626
2030/31	5,781	0	5,781	115	0	717	109	161	4,679
2031/32	5,856	0	5,856	115	0	736	110	166	4,729
2032/33	5,931	0	5,931	115	0	754	110	172	4,780

Notes:

December 31, 2023 Status

2015/2016 , 2020/2021, 2022/2023 Net Firm Demand is not coincident with system peak.

Notes prior to 2024

*Includes residential and commercial/industrial conservation.

**Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.

***Includes energy planner program.

Values shown may be affected due to rounding.

Schedule 3.2

Forecast of Winter Peak Demand (MW)
High Case

(1)	(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
2023/24	5,247	0	5,247	116	0	596	105	120	4,310
2024/25	5,338	0	5,338	115	0	610	106	126	4,381
2025/26	5,437	0	5,437	115	0	626	106	132	4,457
2026/27	5,535	0	5,535	115	0	643	107	138	4,533
2027/28	5,636	0	5,636	115	0	661	107	143	4,608
2028/29	5,736	0	5,736	115	0	680	108	149	4,684
2029/30	5,835	0	5,835	115	0	699	109	155	4,758
2030/31	5,933	0	5,933	115	0	717	109	161	4,831
2031/32	6,031	0	6,031	115	0	736	110	166	4,904
2032/33	6,129	0	6,129	115	0	754	110	172	4,977

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

Schedule 3.2

Forecast of Winter Peak Demand (MW)
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale	Retail *	Interruptible	Residential Load Management	Residential Conservation**	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2023/24	5,210	0	5,210	116	0	596	105	120	4,273
2024/25	5,266	0	5,266	115	0	610	106	126	4,309
2025/26	5,330	0	5,330	115	0	626	106	132	4,350
2026/27	5,391	0	5,391	115	0	643	107	138	4,389
2027/28	5,454	0	5,454	115	0	661	107	143	4,426
2028/29	5,515	0	5,515	115	0	680	108	149	4,463
2029/30	5,575	0	5,575	115	0	699	109	155	4,498
2030/31	5,632	0	5,632	115	0	717	109	161	4,530
2031/32	5,688	0	5,688	115	0	736	110	166	4,561
2032/33	5,742	0	5,742	115	0	754	110	172	4,590

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

Schedule 3.3

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	**Total***	**Residential Conservation****	**Comm./Ind. Conservation**	**Retail**	**Wholesale *****	**Utility Use & Losses**	**Net Energy for Load**	**Load **** Factor %**
2014	19,376	544	306	18,526	0	789	19,315	54.3
2015	19,888	565	316	19,006	0	1,098	20,105	57.1
2016	20,149	584	330	19,234	9	930	20,173	55.2
2017	20,137	598	353	19,186	2	1,110	20,298	56.2
2018	20,634	614	388	19,631	0	1,031	20,662	58.1
2019	20,863	631	449	19,783	0	986	20,770	55.2
2020	21,085	644	487	19,954	0	1,101	21,055	56.2
2021	21,256	656	508	20,093	0	940	21,033	54.7
2022	21,676	679	530	20,467	0	1,105	21,572	55.5
2023	22,059	709	560	20,791	0	976	21,767	53.2
2024	21,626	735	576	20,315	0	1,040	21,355	53.9
2025	21,826	763	597	20,466	0	1,047	21,513	53.8
2026	22,062	793	619	20,651	0	1,056	21,706	53.6
2027	22,300	824	641	20,835	0	1,065	21,900	53.4
2028	22,545	856	662	21,027	0	1,074	22,100	53.1
2029	22,801	888	684	21,229	0	1,083	22,313	53.1
2030	23,063	919	706	21,438	0	1,094	22,532	53.0
2031	23,331	951	727	21,653	0	1,104	22,757	53.0
2032	23,606	982	749	21,875	0	1,115	22,990	52.8
2033	23,883	1,014	771	22,098	0	1,126	23,224	53.0

Notes:

December 31, 2023 Status
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
***Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
****Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

Schedule 3.3

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

(1) 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 %
2024	21,689	735	576	20,379	0	1,044	21,422	53.8
2025	21,954	763	597	20,593	0	1,054	21,647	53.7
2026	22,256	793	619	20,844	0	1,066	21,909	53.5
2027	22,562	824	641	21,096	0	1,078	22,174	53.2
2028	22,877	856	662	21,359	0	1,090	22,449	52.9
2029	23,205	888	684	21,634	0	1,104	22,738	52.9
2030	23,543	919	706	21,918	0	1,118	23,036	52.8
2031	23,888	951	727	22,209	0	1,132	23,342	52.7
2032	24,242	982	749	22,511	0	1,147	23,658	52.5
2033	24,601	1014	771	22,816	0	1,162	23,978	52.6

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

Schedule 3.3

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total*	Residential Conservation**	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load *** Factor %
2024	21,562	735	576	20,251	0	1,036	21,288	53.9
2025	21,700	763	597	20,340	0	1,040	21,380	53.9
2026	21,872	793	619	20,460	0	1,046	21,506	53.7
2027	22,044	824	641	20,579	0	1,051	21,630	53.6
2028	22,222	856	662	20,703	0	1,057	21,760	53.3
2029	22,409	888	684	20,837	0	1,063	21,900	53.4
2030	22,601	919	706	20,976	0	1,070	22,046	53.3
2031	22,797	951	727	21,119	0	1,077	22,195	53.3
2032	23,000	982	749	21,268	0	1,083	22,352	53.2
2033	23,202	1,014	771	21,417	0	1,091	22,509	53.4

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

Schedule 4
Base Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2023 Actual		2024 Forecast		2025 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,347	1,539	4,513	1,583	4,566	1,594
February	3,273	1,391	3,520	1,420	3,557	1,427
March	3,585	1,652	3,561	1,561	3,602	1,570
April	3,678	1,737	3,682	1,633	3,708	1,641
May	3,912	1,914	4,034	1,905	4,059	1,917
June	4,318	2,073	4,331	2,057	4,366	2,073
July	4,312	2,281	4,326	2,150	4,365	2,168
August	4,669	2,357	4,384	2,181	4,421	2,199
September	4,194	2,076	4,230	1,989	4,276	2,007
October	3,801	1,769	3,844	1,838	3,873	1,853
November	3,440	1,491	3,396	1,486	3,436	1,499
December	2,982	1,486	3,873	1,551	3,918	1,564
TOTAL		21,767		21,355		21,513

Notes:
December 31, 2023 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)
	2023 Actual		2024 Forecast		2025 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,347	1,539	4,532	1,587	4,602	1,604
February	3,273	1,391	3,533	1,425	3,583	1,436
March	3,585	1,652	3,575	1,566	3,629	1,579
April	3,678	1,737	3,696	1,637	3,735	1,651
May	3,912	1,914	4,049	1,911	4,090	1,928
June	4,318	2,073	4,348	2,064	4,399	2,087
July	4,312	2,281	4,342	2,158	4,398	2,183
August	4,669	2,357	4,400	2,188	4,454	2,214
September	4,194	2,076	4,246	1,996	4,307	2,020
October	3,801	1,769	3,858	1,844	3,901	1,865
November	3,440	1,491	3,407	1,491	3,460	1,507
December	2,982	1,486	3,886	1,556	3,946	1,573
TOTAL		21,767		21,422		21,647

Notes:
December 31, 2023 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)
	2023 Actual		2024 Forecast		2025 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,347	1,539	4,495	1,578	4,530	1,584
February	3,273	1,391	3,506	1,416	3,530	1,419
March	3,585	1,652	3,548	1,557	3,576	1,561
April	3,678	1,737	3,669	1,628	3,680	1,632
May	3,912	1,914	4,019	1,899	4,029	1,905
June	4,318	2,073	4,315	2,050	4,333	2,060
July	4,312	2,281	4,309	2,143	4,333	2,154
August	4,669	2,357	4,368	2,174	4,388	2,185
September	4,194	2,076	4,215	1,982	4,244	1,994
October	3,801	1,769	3,831	1,832	3,846	1,841
November	3,440	1,491	3,385	1,482	3,413	1,490
December	2,982	1,486	3,860	1,547	3,891	1,555
TOTAL		21,767		21,289		21,380

Notes:
December 31, 2023 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
**Values shown may be affected due to rounding.

Schedule 5

History and Forecast of Fuel Requirements
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
			Actual	Actual										
	Fuel Requirements	Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	652	367	177	102	110	101	103	110	109	85	74	72
(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	19	6	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	19	6	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	124,914	126,239	126,127	123,369	121,463	118,851	118,161	116,001	115,651	116,221	116,636	115,210
(14)	ST	1000 MCF	6,892	5,295	3,280	1,675	2,658	2,232	4,228	1,910	2,767	5,963	6,261	6,259
(15)	CC	1000 MCF	105,985	120,717	122,286	120,513	117,050	115,017	112,094	112,425	109,494	107,023	107,582	106,070
(16)	GT	1000 MCF	12,036	227	561	1,181	1,755	1,602	1,839	1,666	3,390	3,235	2,793	2,881
(17)	Other (Specify)													
(18)	PC	1000 Ton	0	0	0	0	0	0	0	0	0	0	0	0

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

Schedule 6.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources	Unit	Actual 2022	Actual 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(1)	Annual Firm Interchange	GWh	23	21	58	208	150	150	151	150	150	150	151	150
(2)	Nuclear	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal	GWh	1,337	769	349	197	217	200	200	212	209	169	144	139
(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	6	2	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	6	2	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	17,066	17,814	18,406	18,293	17,873	17,620	17,472	17,212	17,034	16,924	16,819	16,721
(15)	ST	GWh	831	473	276	141	225	188	358	160	233	507	532	533
(16)	CC	GWh	14,907	17,323	18,081	18,036	17,479	17,279	16,935	16,889	16,480	16,111	16,021	15,913
(17)	GT	GWh	1,327	18	49	116	169	153	179	163	321	306	266	275
(18)	Renewable	GWh	1,492	1,748	2,471	2,768	3,423	3,891	4,251	4,710	5,113	5,490	5,853	6,191
(19)	Solar	GWh	1,492	1,748	2,471	2,768	3,423	3,891	4,251	4,710	5,113	5,490	5,853	6,191
(20)	Other (Specify)													
(21)	PC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(22)	Net Interchange	GWh	1,600	1,315	(14)	(33)	(35)	(39)	(40)	(38)	(39)	(40)	(40)	(40)
(23)	Purchased Energy from Non-Utility Generators	GWh	49	97	85	85	85	85	85	85	85	85	85	85
(24)	Other	GWh	0	0	0	(5)	(7)	(7)	(19)	(18)	(20)	(21)	(22)	(22)
(25)	Net Energy for Load	GWh	21,572	21,767	21,355	21,513	21,706	21,900	22,100	22,313	22,532	22,757	22,990	23,224

Notes:

Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.
Generation quantities do not reflect periodic testing of distillate fuel oil capability.
Batteries are represented in row (24).

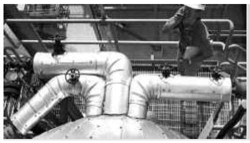
Schedule 6.2

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 2022**	**Actual 2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
(1)	**Annual Firm Interchange**	%	0.1	0.1	0.3	1.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6
(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**	%	6.2	3.5	1.6	0.9	1.0	0.9	0.9	1.0	0.9	0.7	0.6	0.6
(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	0.01	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	0.01	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**	%	79.1	81.8	86.2	85.0	82.3	80.5	79.1	77.1	75.6	74.4	73.2	72.0
(15)	**ST**	%	3.9	2.2	1.3	0.7	1.0	0.9	1.6	0.7	1.0	2.2	2.3	2.3
(16)	**CC**	%	69.1	79.6	84.7	83.8	80.5	78.9	76.6	75.7	73.1	70.8	69.7	68.5
(17)	**GT**	%	6.2	0.1	0.2	0.5	0.8	0.7	0.8	0.7	1.4	1.3	1.2	1.2
(18)	**Renewable**	%	6.9	8.0	11.6	12.9	15.8	17.8	19.2	21.1	22.7	24.1	25.5	26.7
(19)	**Solar**	%	6.9	8.0	11.6	12.9	15.8	17.8	19.2	21.1	22.7	24.1	25.5	26.7
(20)	**Other (Specify)**													
(21)	**PC**	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(22)	**Net Interchange**	%	7.4	6.0	(0.1)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)
(23)	**Purchased Energy from Non-Utility Generators**	%	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
(24)	**Other**	%	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
(25)	**Net Energy for Load**	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Notes:
Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.
Generation quantities do not reflect periodic testing of distillate fuel oil capability.
Batteries are represented in row (24).

Chapter V



FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility changes and additions shown in Schedule 8.1 integrate energy efficiency and conservation programs and generating resources to provide economical, reliable service to TEC's customers. Various energy resource plan alternatives, comprised of a mixture of generating technologies, purchased power, and cost-effective energy efficiency and conservation programs, are developed to determine this plan. These alternatives are combined with existing resources and analyzed to determine the resource options which best meets TEC's future system demand and energy requirements. A detailed discussion of TEC's integrated resource planning process is included in Chapter III.

The results of the IRP process provide TEC with a cost-effective plan that maintains system reliability and environmental requirements while considering technology, availability, dispatchability, resiliency, and lead times for construction. To cost-effectively meet the expected system demand and energy requirements over the next ten years, solar PV, base load, intermediate, and distributed energy resources are needed. TEC will add incremental utility-scale solar PV capacity and is researching the viability of additional renewable technologies. The completion of the Big Bend Power Station modernization through the repowering of Unit 1 to a 2x1 combined cycle unit, the retirement of Unit 2 and Unit 3, and the advanced hardware upgrades on the CTs at Bayside provide low-cost, reliable, and grid-friendly options for customers. Additionally, distributed energy resources such as batteries and reciprocating engines provide reliability and resiliency to our system. The operating and cost parameters are shown in Schedule 9 for proposed generating facilities.

TEC will continue to compare purchased power options as an alternative and/or enhancement 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 2024, TEC plans for 196 MW of cogeneration capacity operating in its service area.

Table IV-I **2024 Cogeneration Capacity Forecast**	**Capacity (MW)**
Self-service [1]	137
Firm to Tampa Electric	0
As-available to Tampa Electric	6
Export to other systems	53
Total	196

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

FIRM INTERCHANGE SALES AND PURCHASES

TEC has one (1) long-term firm purchase power agreement. That agreement is with Pasco County (Pasco) for TEC to purchase 18 MW from Pasco's waste-to-energy (WTE) facility begins in 2025. The term is 10 years, beginning January 2025 and continuing through December 2034. The company also has three (3) short-term agreements that provide firm capacity during the winter of 2024. The short-term purchases are (i) 75 MW from the Florida Municipal Power Agency (FMPA), (ii) 75 MW from Orlando Utilities Commission and (iii) 250 MW from Duke Energy Florida (DEF). These winter purchases provide firm capacity for the period January through February 2024.

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 natural gas and solar for its energy requirements. TEC has long-term 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, TEC forecasts serving net energy for load in 2024 with 86.2% natural gas, 11.6% solar, 1.6% coal, and less than one (1) percent of other resources, such as non-firm purchases from the market and non-utility generators. Some of the company's generating units have dual-fuel (i.e., natural gas or oil) capability, which enhances system reliability, increases resiliency, and provides fuel cost reduction opportunities.

ENVIRONMENTAL CONSIDERATIONS

Air Quality

TEC continually strives to reduce emissions from its generating facilities, and since 2000, has reduced sulfur dioxide, nitrogen oxide, particulate matter and mercury emissions by 96% or more. Carbon emissions have also been reduced by more than 50%, and TEC has committed to a 60% reduction of carbon emissions by 2025, 80% by 2040, and has a vision to achieve net zero carbon emissions by 2050.

The installation of 1,350 megawatts of solar power by the end of 2024 enabled the company to continue to reduce its dependence on carbon-based fuels. 13% of TEC's energy will be fueled by the sun, and TEC continues to be a leader in solar capacity in Florida.

TEC's emission reduction activities also include:

1. Completed the modernization of Big Bend Unit 1 combined cycle unit and retired Unit 2.

2. The retirement of Big Bend Unit 3 in April of 2023.

3. The Polk Power Station combined-cycle project improved system reliability and efficiency, and reduced emissions system-wide.

4. The upgrade of gas path components on Bayside Power Station's Unit 1 and Unit 2 combustion turbines will increase output, efficiency and reliability while reducing fuel consumption.

5. Energy storage capacity that will capture low cost generation and discharge when it's needed most.

Water Conservation

TEC's Big Bend and Polk Power Station use reclaimed water from local municipalities to minimize the use of potable water and groundwater for plant processes. Most of the properties purchased by TEC for solar generation are former agricultural lands with existing water use permits. When land is sold to new owners, Southwest Florida Water Management District (SWFWMD) rules require that these water permits are transferred as well. Since solar generation requires no water, TEC conserves this groundwater, which otherwise would have pumped and used for agricultural needs. To date, TEC's acquisition of land for the development of solar power has saved more than 6.1 billion gallons of water, which significantly helps an area of the state that has critical concerns over water use.

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. Bayside Power Station replaced the circulator pumps on Unit 1 in 2023, which included fish friendly screens and a fish return system, with Unit 2 to be included in 2024. Tampa Electric is negotiating an alternative schedule for Big Bend (as allowed by the rule) but completed a portion of the compliance requirements with the Big Bend modernization project with the installation of fish-friendly modified traveling screens and a fish return on modernized Unit 1. The remainder of the compliance requirements for Big Bend Station are to be determined and completed at a later date.

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

The final Effluent Limitations Guidelines (ELG) were published on November 3, 2015. The ELGs establish limits for wastewater discharges from flue gas desulfurization (FGD) processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals, gasification processes, and flue gas mercury controls. Big Bend completed construction of a deep injection well system in December 2023 for disposal of FGD wastewater, bottom ash transport water, stormwater and other process wastewaters, which means ELG are no longer applicable

Solid Waste

The Coal Combustion Residuals Rule (CCR) became effective on October 19, 2015. The former Big Bend Unit #4 Economizer Ash & Pyrites Pond System (EAPPS), converted Units 1-3 West Slag Disposal Pond (WSDP) and North Gypsum Stackout Area (NGSA) were covered by this rule. Three ECRC projects were proposed and approved by the Commission for these operating units to comply with the CCR Rule requirements, as follows. The WSDP was remediated and lined in 2020 to allow for continued storm water storage and the EAPPS Closure Project was completed in 2021 by removing and disposing of the CCRs offsite and restoring the site. Phase III of the NGSA Drainage Enhancements Project were initiated in 2023 and will be completed in 2024. The South Gypsum Storage Area Closure Project was completed as a component of the Big Bend Modernization in January 2020. There are no other CCR units at the Big Bend, Polk or Bayside Power Stations currently regulated under the rule.

Schedule 7.1

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Firm Capacity	Firm Capacity Import	Firm Capacity Export		Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	QF MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2024	5,314	0	0	0	5,314	4,143	1,171	28%	0	1,171	28%
2025	5,439	18	0	0	5,457	4,182	1,275	30%	0	1,275	30%
2026	5,486	18	0	0	5,504	4,222	1,282	30%	0	1,282	30%
2027	5,488	18	0	0	5,506	4,261	1,245	29%	0	1,245	29%
2028	5,559	18	0	0	5,577	4,302	1,274	30%	0	1,274	30%
2029	5,560	18	0	0	5,578	4,343	1,234	28%	0	1,234	28%
2030	5,781	18	0	0	5,799	4,385	1,414	32%	0	1,414	32%
2031	5,780	18	0	0	5,798	4,427	1,371	31%	0	1,371	31%
2032	5,780	18	0	0	5,798	4,469	1,329	30%	0	1,329	30%
2033	5,779	18	0	0	5,797	4,511	1,287	29%	0	1,287	29%

Values shown may be affected due to rounding.
92° F at time of Peak.

Schedule 7.2

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Firm Capacity	Firm Capacity Import	Firm Capacity Export		Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	QF MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2023-24	5,194	400	0	0	5,594	4,292	1,302	30%	0	1,302	30%
2024-25	5,323	18	0	0	5,341	4,345	995	23%	0	995	23%
2025-26	5,403	18	0	0	5,421	4,404	1,018	23%	0	1,018	23%
2026-27	5,441	18	0	0	5,459	4,461	998	22%	0	998	22%
2027-28	5,511	18	0	0	5,529	4,517	1,012	22%	0	1,012	22%
2028-29	5,511	18	0	0	5,529	4,572	957	21%	0	957	21%
2029-30	5,758	18	0	0	5,776	4,626	1,149	25%	0	1,149	25%
2030-31	5,758	18	0	0	5,776	4,679	1,097	23%	0	1,097	23%
2031-32	5,758	18	0	0	5,776	4,729	1,046	22%	0	1,046	22%
2032-33	5,758	18	0	0	5,776	4,780	996	21%	0	996	21%

Values shown may be affected due to rounding.
31° F at time of Peak.

Schedule 7.2.1*

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Firm Capacity	Firm Capacity Import	Firm Capacity Export		Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	QF MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2023-24	5,194	400	0	0	5,594	4,498	1,096	24%	0	1,096	24%
2024-25	5,323	18	0	0	5,341	4,554	786	17%	0	786	17%
2025-26	5,403	18	0	0	5,421	4,617	805	17%	0	805	17%
2026-27	5,441	18	0	0	5,459	4,677	782	17%	0	782	17%
2027-28	5,511	18	0	0	5,529	4,737	792	17%	0	792	17%
2028-29	5,511	18	0	0	5,529	4,795	734	15%	0	734	15%
2029-30	5,758	18	0	0	5,776	4,852	923	19%	0	923	19%
2030-31	5,758	18	0	0	5,776	4,908	868	18%	0	868	18%
2031-32	5,758	18	0	0	5,776	4,961	814	16%	0	814	16%
2032-33	5,758	18	0	0	5,776	5,015	761	15%	0	761	15%

Values shown may be affected due to rounding.
* For information purposes only
** 29° F at time of Peak.

Schedule 8.1
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.		Const.	Commercial	Expected	Gen. Max.	Firm 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
2024														
Bayside 2 Enhancement	2	Bayside	CC	NG	NA	PL	NA	-	5/24	*	74,000	72.0	74.0	U
Dover Energy Storage Capacity	1	Hillsborough	BA	N/A	N/A	N/A	N/A	-	9/24	*	15,000	15.0	15.0	U
English Creek Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/24	*	23,000	1.2	-	U
Bullfrog Creek Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/24	*	74,500	3.7	-	U
Solar Degradation [2]	N/A											(1.7)	-	
											2024 Changes and Additions:	90.2	89.0	
2025														
Lake Mabel Energy Storage Capacity	1	Polk	BA	N/A	NA	N/A	N/A	-	1/25	*	40,000	40.0	40.0	U
Wimauma Energy Storage Capacity	1	Hillsborough	BA	N/A	N/A	N/A	N/A	-	2/25	*	40,000	40.0	40.0	U
South Tampa Energy Storage Capacity	1	Hillsborough	BA	N/A	N/A	N/A	N/A	-	4/25	*	20,000	20.0	20.0	U
Polk Unit 1 Simple Cycle Conversion	1	Polk	CT	NG	N/A	PL	N/A	-	5/25	9/36	204,000	(30.0)	(17.0)	P
South Tampa Resilience Project [4]	1	Hillsborough	IC	NG	NA	PL	N/A	-	7/25	*	75,200	75.2	75.2	U
Duette Solar [1]	1	Manatee	PV	SOLAR	NA	NA	NA	-	12/25	*	74,500	3.7	-	P
Cottonmouth Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/25	*	74,500	3.7	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2025 Changes and Additions:	150.7	158.2	
2026														
Big Four Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	5/26	*	74,500	3.7	-	P
Farmland Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/26	*	54,400	2.7	-	P
Brewster Solar [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/26	*	38,800	0.6	-	P
Wimauma 3 Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/26	*	74,500	1.1	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2026 Changes and Additions:	6.2	-	

Notes:

* Undetermined
1 Solar MW values reflect capacity at time of peak. The firm capacity shows expected capacity values for the projected incremental solar additions.
2 Solar capacity degrades at approximately 0.4% every year.
Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.
3 Muliple Sites, each not to exceed 74.5MW
4 South Tampa Resiliency Project is transmission constrained to 37.6MW until Summer 2026.

Schedule 8.1
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.		Const.	Commercial	Expected	Gen. Max.	Firm 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
2027														
Clear Springs I Solar [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/27	*	74,500	1.1	-	P
Future Solar 1 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/27	*	74,500	1.1	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2027 Changes and Additions:	0.3	-	
2028														
Battery Storage 1	1	Unknown	BA	N/A	N/A	N/A	N/A	-	1/28	*	70,000	70.0	70.0	P
Clear Springs II Solar [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/28	*	74,500	1.1	-	P
Mattaniah Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/28	*	55,000	0.8	-	P
Future Solar 2 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/28	*	74,500	1.1	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2028 Changes and Additions:	71.1	70.0	
2029														
Future Solar 3 [1,3]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/29	*	149,000	2.2	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2029 Changes and Additions:	0.3	-	

Notes:

* Undetermined
1 Solar MW values reflect capacity at time of peak. The firm capacity shows expected capacity values for the projected incremental solar additions.
2 Solar capacity degrades at approximately 0.4% every year.
Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.
3 Muliple Sites, each not to exceed 74.5MW
4 South Tampa Resiliency Project is transmission constrained to 37.6MW until Summer 2026.

Schedule 8.1
Planned and Prospective Generating Facility Additions and Changes

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Primary	(6) Fuel Alternate	(7) Fuel Trans. Primary	(8) Fuel Trans. Alternate	(9) Const. Start Mo/Yr	(10) Commercial In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen. Max. Nameplate kW	(13) Firm Net Capability Summer MW	(14) Firm Net Capability Winter MW	(15) Status
2030														
Future CT 1	1	Unknown	CT	NG	NA	PL	N/A	-	1/30	*	255,000	222.0	247.0	P
Future Solar 4 [1,3]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/30	*	149,000	2.2	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2030 Changes and Additions:	222.3	247.0	
2031														
Future Solar 5 [1,3]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/31	*	149,000	2.2	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2031 Changes and Additions:	0.3	-	
2032														
Future Solar 6 [1,3]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/32	*	149,000	2.2	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2032 Changes and Additions:	0.3	-	
2033														
Future Solar 7 [1,3]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/33	*	149,000	2.2	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2033 Changes and Additions:	0.3	-	

Notes:

* Undetermined
[1] Solar MW values reflect capacity at time of peak. The firm capacity shows expected capacity values for the projected incremental solar additions.
[2] Solar capacity degrades at approximately 0.4% every year.
Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.
[3] Muliple Sites, each not to exceed 74.5MW
[4] South Tampa Resiliency Project is transmission constrained to 37.6MW until Summer 2026.

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Bayside 2 Enhancement
(2)	Net Capability	
	A. Summer	72 MW
	B. Winter	74 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	February 2024
	B. Commercial In-Service Date	May 2024
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	U
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	15
	Total Installed Cost[1] (In-Service Year $/kW)	407
	Direct Construction Cost ($/kW)	398
	AFUDC[1] Amount ($/kW)	-
	Escalation ($/kW)	8.77
	Fixed O&M (In-Service Year $/kW – Yr)	-
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	1.21

[1] Total installed cost includes transmission interconnection

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Dover Energy Storage Capacity
(2)	Net Capability	
	A. Summer	15.0 MW-ac
	B. Winter	15.0 MW-ac
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	November 2023
	B. Commercial In-Service Date	September 2024
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	1 Acre
(9)	Construction Status	U
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost (In-Service Year $/kW)	1,285
	Direct Construction Cost[1] ($/kW)	1,232
	AFUDC Amount ($/kW)	52.90
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	4.00
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.87

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	English Creek Solar
(2)	Net Capability	
	A. Summer	23.0 MW-ac
	B. Winter	23.0 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2024
	B. Commercial In-Service Date	December 2024
(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	+240 Acres
(9)	Construction Status	U
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,878
	Direct Construction Cost[1] ($/kW)	1,754
	AFUDC Amount ($/kW)	123.66
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.15
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.74

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Bullfrog Creek Solar
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2024
	B. Commercial In-Service Date	December 2024
(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	+570 Acres
(9)	Construction Status	U
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,471
	Direct Construction Cost[1,3] ($/kW)	1,402
	AFUDC Amount ($/kW)	68.04
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.15
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.73

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land Lease costs not included

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Lake Mabel Energy Storage Capacity
(2)	Net Capability	
	A. Summer	40 MW-ac
	B. Winter	40 MW-ac
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2024
	B. Commercial In-Service Date	January 2025
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	2 Acres
(9)	Construction Status	U
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost (In-Service Year $/kW)	1,281
	Direct Construction Cost[1] ($/kW)	1,215
	AFUDC Amount ($/kW)	65.57
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	4.19
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.94

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Wimauma Energy Storage Capacity
(2)	Net Capability	
	A. Summer	40 MW-ac
	B. Winter	40 MW-ac
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	February 2024
	B. Commercial In-Service Date	February 2025
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	2 Acres
(9)	Construction Status	U
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost (In-Service Year $/kW)	1,108
	Direct Construction Cost[1] ($/kW)	1,067
	AFUDC Amount ($/kW)	40.64
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	4.19
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.94

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	South Tampa Energy Storage Capacity
(2)	Net Capability	
	A. Summer	20 MW-ac
	B. Winter	20 MW-ac
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	March 2024
	B. Commercial In-Service Date	April 2025
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	1 Acre
(9)	Construction Status	U
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost (In-Service Year $/kW)	1,410
	Direct Construction Cost[1] ($/kW)	1,351
	AFUDC Amount ($/kW)	59.06
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	4.19
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.92

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Polk Unit 1 Simple Cycle Conversion
(2)	Net Capability	
	A. Summer	190 MW
	B. Winter	203 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	March 2025
	B. Commercial In-Service Date	May 2025
(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	Planned
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	5%
	Forced Outage Factor (FOF)	2%
	Equivalent Availability Factor (EAF)	93%
	Resulting Capacity Factor	5%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	10,643 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	12
	Total Installed Cost (In-Service Year $/kW)	397
	Direct Construction Cost[1] ($/kW)	383
	AFUDC Amount ($/kW)	13.79
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	-
	Variable O&M (In-Service Year $/MWh)	5.59
	K-Factor	-

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	South Tampa Resilience Project
(2)	Net Capability	
	A. Summer	75.2 MW (Consisting of 4 Units)
	B. Winter	75.2 MW (Consisting of 4 Units)
(3)	Technology Type	Engine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	December 2022
	B. Commercial In-Service Date	July 2025
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Selective Catalytic Reduction (SCR)
(7)	Cooling Method	Closed Loop Cooling
(8)	Total Site Area	2 Acres
(9)	Construction Status	U
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	2%
	Forced Outage Factor (FOF)	2%
	Equivalent Availability Factor (EAF)	96%
	Resulting Capacity Factor	8%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	8,300 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	2,224
	Direct Construction Cost[1] ($/kW)	2,056
	AFUDC Amount ($/kW)	168.3
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	20.02
	Variable O&M (In-Service Year $/MWh)	2.41
	K-Factor	1.26

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Duette Solar
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2025
	B. Commercial In-Service Date	December 2025
(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	+690 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,536
	Direct Construction Cost[1,3] ($/kW)	1,466
	AFUDC Amount ($/kW)	70.41
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.53
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.79

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Cottonmouth Solar
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2025
	B. Commercial In-Service Date	December 2025
(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	+530 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,492
	Direct Construction Cost[1,3] ($/kW)	1,410
	AFUDC Amount ($/kW)	81.97
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.53
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.74

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land Lease costs not included

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Four Solar
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	April 2025
	B. Commercial In-Service Date	May 2026
(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	+680 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,399
	Direct Construction Cost[1,3] ($/kW)	1,332
	AFUDC Amount ($/kW)	66.84
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.82
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.76

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land Lease costs not included

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Farmland Solar
(2)	Net Capability	
	A. Summer	54.4 MW-ac
	B. Winter	54.4 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2026
	B. Commercial In-Service Date	December 2026
(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	+330 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,755
	Direct Construction Cost[1,3] ($/kW)	1,641
	AFUDC Amount ($/kW)	113.07
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.92
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.82

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Brewster Solar
(2)	Net Capability	
	A. Summer	38.8 MW-ac
	B. Winter	38.8 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2026
	B. Commercial In-Service Date	December 2026
(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	+200 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,475
	Direct Construction Cost[1,3] ($/kW)	1,411
	AFUDC Amount ($/kW)	64.55
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.92
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.68

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Wimauma 3 Solar
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2026
	B. Commercial In-Service Date	December 2026
(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	+680 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	28%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,695
	Direct Construction Cost[1,3] ($/kW)	1,637
	AFUDC Amount ($/kW)	57.42
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.92
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.75

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land Lease costs not included

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Clear Springs I Solar
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2027
	B. Commercial In-Service Date	December 2027
(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	+450 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	28%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,677
	Direct Construction Cost[1,3] ($/kW)	1,592
	AFUDC Amount ($/kW)	84.32
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	19.32
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.74

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar I
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2027
	B. Commercial In-Service Date	December 2027
(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	Undetermined
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	28%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,854
	Direct Construction Cost[1,3] ($/kW)	1,754
	AFUDC Amount ($/kW)	100.15
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	19.32
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.79

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage 1
(2)	Net Capability	
	A. Summer	70 MW
	B. Winter	70 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2027
	B. Commercial In-Service Date	January 2028
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(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)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost (In-Service Year $/kW)	2,284
	Direct Construction Cost[1] ($/kW)	2,025
	AFUDC Amount ($/kW)	158.95
	Escalation ($/kW)	99.99
	Fixed O&M (In-Service Year $/kW – Yr)	6.66
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.86

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Clear Springs II Solar
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2028
	B. Commercial In-Service Date	December 2028
(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	Undetermined
(9)	Construction Status	Planned
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	28%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,708
	Direct Construction Cost[1,3] ($/kW)	1,615
	AFUDC Amount ($/kW)	93.13
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	19.72
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.76

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Mattaniah Solar
(2)	Net Capability	
	A. Summer	55.0 MW-ac
	B. Winter	55.0 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2028
	B. Commercial In-Service Date	December 2028
(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	Undetermined
(9)	Construction Status	Planned
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,614
	Direct Construction Cost[1,3] ($/kW)	1,514
	AFUDC Amount ($/kW)	100.01
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	19.72
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.88

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 2
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2028
	B. Commercial In-Service Date	December 2028
(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	Undetermined
(9)	Construction Status	Planned
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	28%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	1,690
	Direct Construction Cost[1,3] ($/kW)	1,633
	AFUDC Amount ($/kW)	57.42
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	19.72
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.78

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 3 (Multiple Sites, each not to exceed 74.5MW)
(2)	Net Capability	
	A. Summer	149.0 MW-ac
	B. Winter	149.0 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2029
	B. Commercial In-Service Date	December 2029
(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	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)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	TBD
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	TBD
	Direct Construction Cost[1] ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future CT
(2)	Net Capability	
	A. Summer	222 MW
	B. Winter	247 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	TBD
	B. Commercial In-Service Date	January 2030
(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	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	4%
	Forced Outage Factor (FOF)	2%
	Equivalent Availability Factor (EAF)	94%
	Resulting Capacity Factor	8%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	10,867 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	954
	Direct Construction Cost[1] ($/kW)	823
	AFUDC Amount ($/kW)	65.72
	Escalation ($/kW)	64.70
	Fixed O&M (In-Service Year $/kW – Yr)	12.38
	Variable O&M (In-Service Year $/MWh)	1.33
	K-Factor	1.34

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 4 (Multiple Sites, each not to exceed 74.5MW)
(2)	Net Capability	
	A. Summer	149.0 MW-ac
	B. Winter	149.0 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2030
	B. Commercial In-Service Date	December 2030
(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	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)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	TBD
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	TBD
	Direct Construction Cost[1] ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 5 (Multiple Sites, each not to exceed 74.5MW)
(2)	Net Capability	
	A. Summer	149.0 MW-ac
	B. Winter	149.0 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2031
	B. Commercial In-Service Date	December 2031
(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	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)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	TBD
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	TBD
	Direct Construction Cost[1] ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 6 (Multiple Sites, each not to exceed 74.5MW)
(2)	Net Capability	
	A. Summer	149.0 MW-ac
	B. Winter	149.0 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2032
	B. Commercial In-Service Date	December 2032
(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	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)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	TBD
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	TBD
	Direct Construction Cost[1] ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 7 (Multiple Sites, each not to exceed 74.5MW)
(2)	Net Capability	
	A. Summer	149.0 MW-ac
	B. Winter	149.0 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	January 2033
	B. Commercial In-Service Date	December 2033
(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	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)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor	TBD
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (In-Service Year $/kW)	TBD
	Direct Construction Cost[1] ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines
As of December 31, 2023

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
Bayside CC 2	Bayside CC 2 does not require any new transmission lines ****	-	-	-	230 kV	May 2024	-	Gannon	None
Polk CT 1*****	Polk CT 1 does not require any new transmission lines	-	-	-	230 kV	May 2025	-	Polk	None
Farmland Solar*****	Farmland Solar - Farmland	1	Not Determined	1	230 kV	December 2026	Included in total installed cost on Schedule 9	Farmland Solar Station; Farmland Substation	None

Note:
* Specific information related to "Unsited" units unknown at this time.
** Approximate mileage listed is based on construction activity, not overall circuit length.
*** Cumulative capital investment at the in-service date. Cost included in total installed cost on Schedule 9.
**** Interconnection request studies pertaining to a Large Generating Facility have been completed and the unit does not require any new transmission lines.
***** Interconnection Requests pertaining to a Large Generating Facility have been submitted for these units. Pending completion of the Interconnection Request studies, the information provided on Schedule 10 may change.

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Chapter VI

ENVIRONMENTAL AND LAND USE INFORMATION

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). The solar sites identified in Schedule 1 are spread across Hillsborough, Polk, and Pasco counties (See Figure VI-IV). Additional land use requirements and/or alternative site locations are currently under consideration to accommodate the addition of future solar PV generation facilities and distributed energy resources.

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

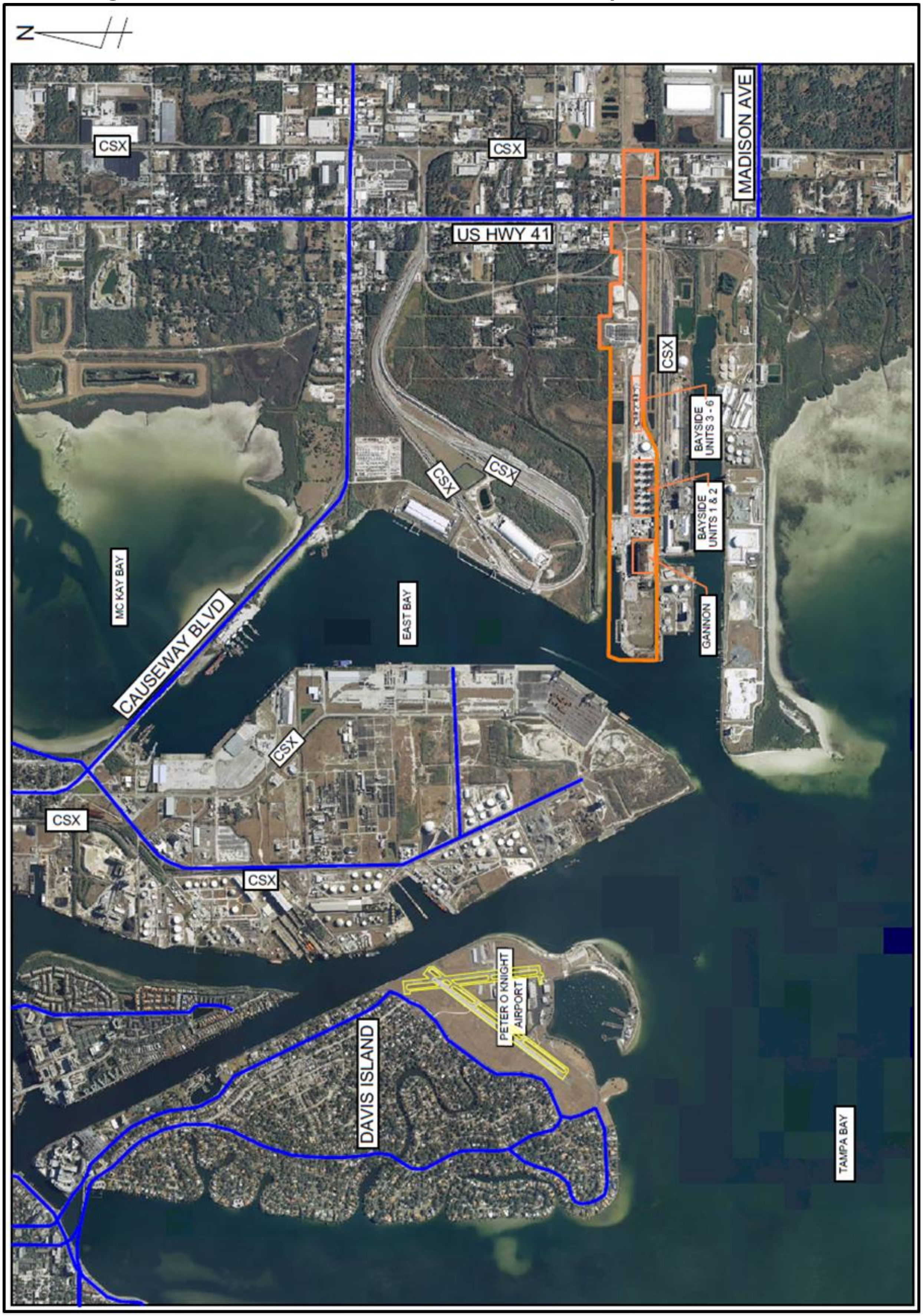

Figure VI-II: Site Location of Polk Power Station

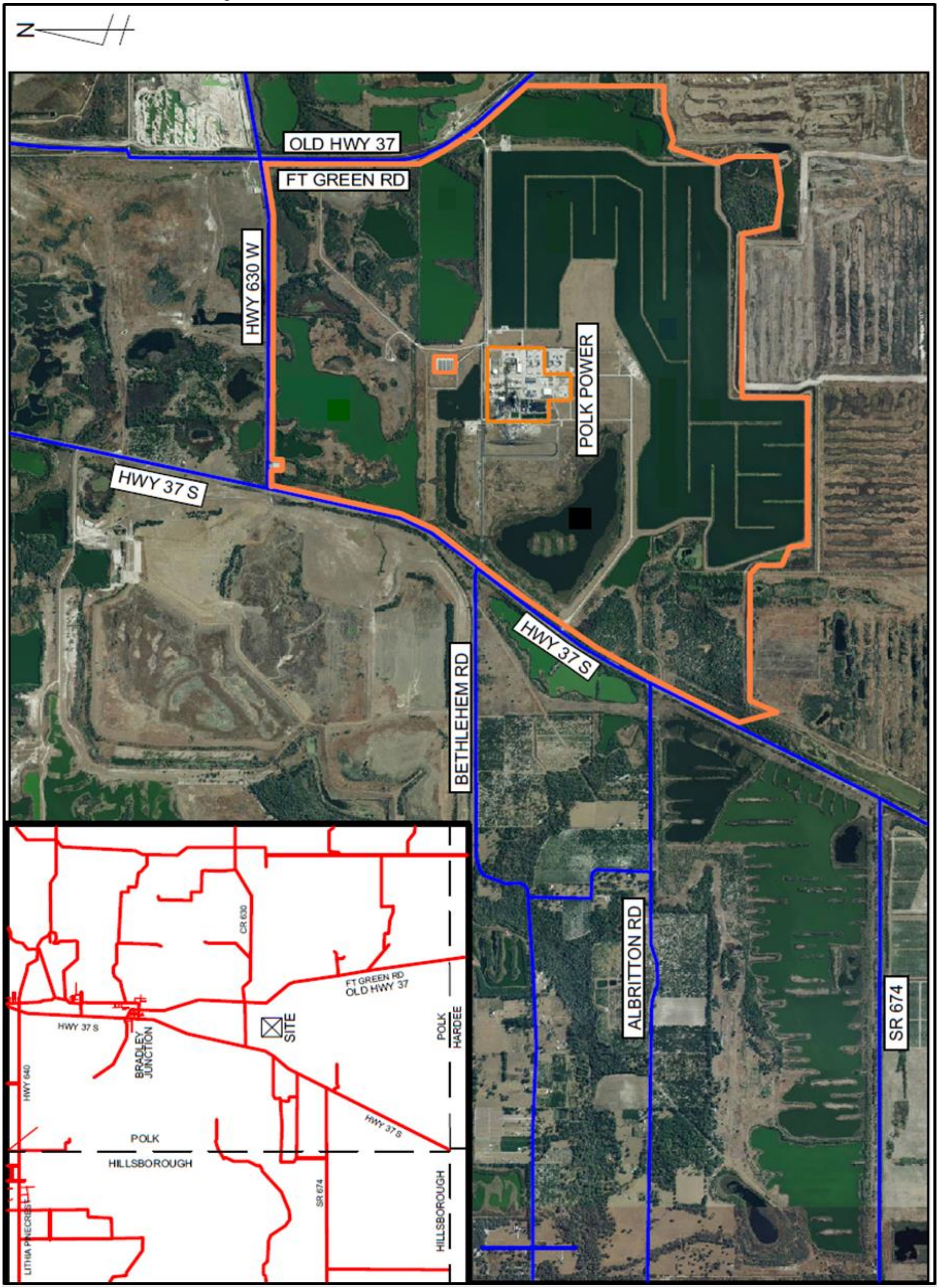

Figure VI-III: Site Location of Big Bend Power Station

Figure VI-IV: Site Location of Solar Power Stations