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April 1, 2021

VIA: ELECTRONIC FILING

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

Re: Tampa Electric Company's 2021 Ten-Year Site Plan

Dear Mr. Teitzman:

Attached for filing on behalf of Tampa Electric Company is the company's January 2021 to December 2030 Ten-Year Site Plan.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/bmp
Attachment
cc: Donald Phillips - DPhillip@psc.state.fl.us
Damian Kistner - Dkistner@psc.state.fl.us

TEN-YEAR SITE PLAN

JANUARY 2021 - DECEMBER 2030

For Electrical Generating Facilities and Associated Transmission Lines

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TEC022420

Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2021 to December 2030

Submitted to: Florida Public Service Commission
April 1, 2021

TABLE OF CONTENTS

LIST OF SCHEDULES & TABLES

LIST OF FIGURES

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GLOSSARY OF TERMS

CODE IDENTIFICATION SHEET

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

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Executive Summary

Tampa Electric Company's (TEC) 2021 Ten-Year Site Plan (TYSP) features plans to enhance electric generating capability as part of our efforts to meet projected incremental resource needs for 2021 through 2030. The 2021 TYSP provides the Florida Public Service Commission (FPSC) with assurance that TEC will be able to supply cost-effective alternatives to ensure the delivery of adequate, safe, environmentally responsible, and reliable power to TEC's customers.

The resource additions are based on TEC's Integrated Resource Planning (IRP) process, which incorporates an on-going 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.

Investments in renewable generation enables fuel savings for customers, energy diversification, and continues TEC's commitment towards a lower carbon future. The company has announced its plans to deploy more solar projects over the next several years, bringing the total committed solar capacity to 1,255 MW or approximately 20.7% of the total installed capacity by Summer of 2024. As a result, TEC projects to produce more energy from solar than coal generation.

TEC is also committed to pursuing cost-effective improvements on the existing generating fleet. The first phase of the Big Bend modernization project will commence with the deployment of two simple cycle CTs and the retirement of Unit 2 in December 2021. The waste heat from these CTs will then be captured for use in the modernized Big Bend Unit 1 steam turbine as a natural gas combined cycle plant by the end of 2022. Beginning in 2021 additional natural gas burners will be added to Big Bend Unit 4 that will allow the unit to reach full capability on coal, natural gas, or a combination of the two to enhance reliability and take advantage of economic opportunities. In addition, between 2022 and 2023, the Bayside station will undergo advanced hardware upgrades to improve efficiency, generating capacity, and operational flexibility to its seven CTs.

The company plans to meet the power needs of its customers through additional resources and seeks to do so in the most cost-effective way possible while seeking cleaner and greener lower carbon emitting assets. The future solar in this expansion plan provides energy diversity by reducing both reliance on natural gas and its associated price volatility risk for customers.

In addition to enhancements of the existing assets and the aforementioned solar, TEC plans to add approximately 300 MW of battery storage capacity and approximately 37 MW of capacity using reciprocating engines over the study horizon. These distributed resources provide peaking capacity, fuel savings, and the potential for system operational benefits, avoided transmission and distribution investment, and reduced line losses.

The portfolio of resource additions presented in this TYSP work in concert to provide cost savings, environmental, and reliability benefits for customers while also enhancing the system's operational flexibility, energy diversity, and resiliency.

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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 multiple solar facilities.

Big Bend Power Station

Big Bend Units 1-4 are four (4) steam units equipped with desulfurization scrubbers, electrostatic precipitators, and Selective Catalytic Reduction (SCR) air pollution control systems. All four units can be fired with natural gas or coal. Natural gas is the primary fuel on 1,2 and 3. 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 (4) aero derivative combustion turbines. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) heat recovery steam generators (HRSGs) and one (1) steam turbine. Bayside Unit 2 utilizes four (4) combustion turbines, four (4) HRSGs and one (1) steam turbine. Bayside 3, 4, 5, and 6 are four (4) natural gas fired aero-derivative combustion turbines.

Polk Power Station

Polk Unit 1 is a dual fuel IGCC / natural gas 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 of the combustion turbines can also be fired with distillate oil.

Solar

As of December 31, 2020, TEC owns 595 MW_{AC} of solar throughout our territory. It consists of 571.9 MW_{AC} single axis tracking PV solar arrays at nine solar sites throughout Hillsborough and Polk counties, a 1.6 MW_{AC} fixed tilt solar PV rooftop canopy array located atop the south parking garage at Tampa International Airport, a 1.4 MW_{AC} fixed tilt solar PV ground canopy array located at LEGOLAND® Florida, and a 19.8 MW_{AC} single axis tracking solar station coupled with a 12.6 MW battery storage unit located at Big Bend Power Station.

Schedule 1
Existing Generating Facilities
As of December 31, 2020

(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		ST	NG	NG	PL	PL	NA	10/70	**	445,500	385	395
	2		ST	NG	NG	PL	PL	NA	04/73	12/21	445,500	385	395
	3		ST	NG	NG	PL	PL	NA	05/76	04/23	445,500	395	400
	4		ST	BIT	NG	WA/RR	PL	NA	02/85	**	486,000	437	442
	CT 4		GT	NG	NA	PL	NA	*	08/09	**	69,900	56	61
Big Bend Total											**1,892,400**	**1,658**	**1,693**
Bayside		**Hillsborough Co.**											
	1		CC	NG	NA	PL	NA	NA	04/03	**	809,060	701	792
	2		CC	NG	NA	PL	NA	NA	01/04	**	1,205,100	929	1,047
	3		GT	NG	NA	PL	NA	NA	07/09	**	69,900	56	61
	4		GT	NG	NA	PL	NA	NA	07/09	**	69,900	56	61
	5		GT	NG	NA	PL	NA	NA	04/09	**	69,900	56	61
	6		GT	NG	NA	PL	NA	NA	04/09	**	69,900	56	61
Bayside Total											**2,293,759**	**1,854**	**2,083**
Polk		**Polk Co.**											
	1		IGCC	PC/BIT	NG	WA/TK	PL	*	09/96	**	326,299	220	220
	2		CC	NG	DFO	PL	TK	*	01/17	**	1,216,080	1,061	1,200
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**	**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 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
Solar Total*****											**594,800**	**595**	**595**
											TOTAL	**5,388**	**5,791**

Notes:

* Limited by environmental permit

** Undetermined

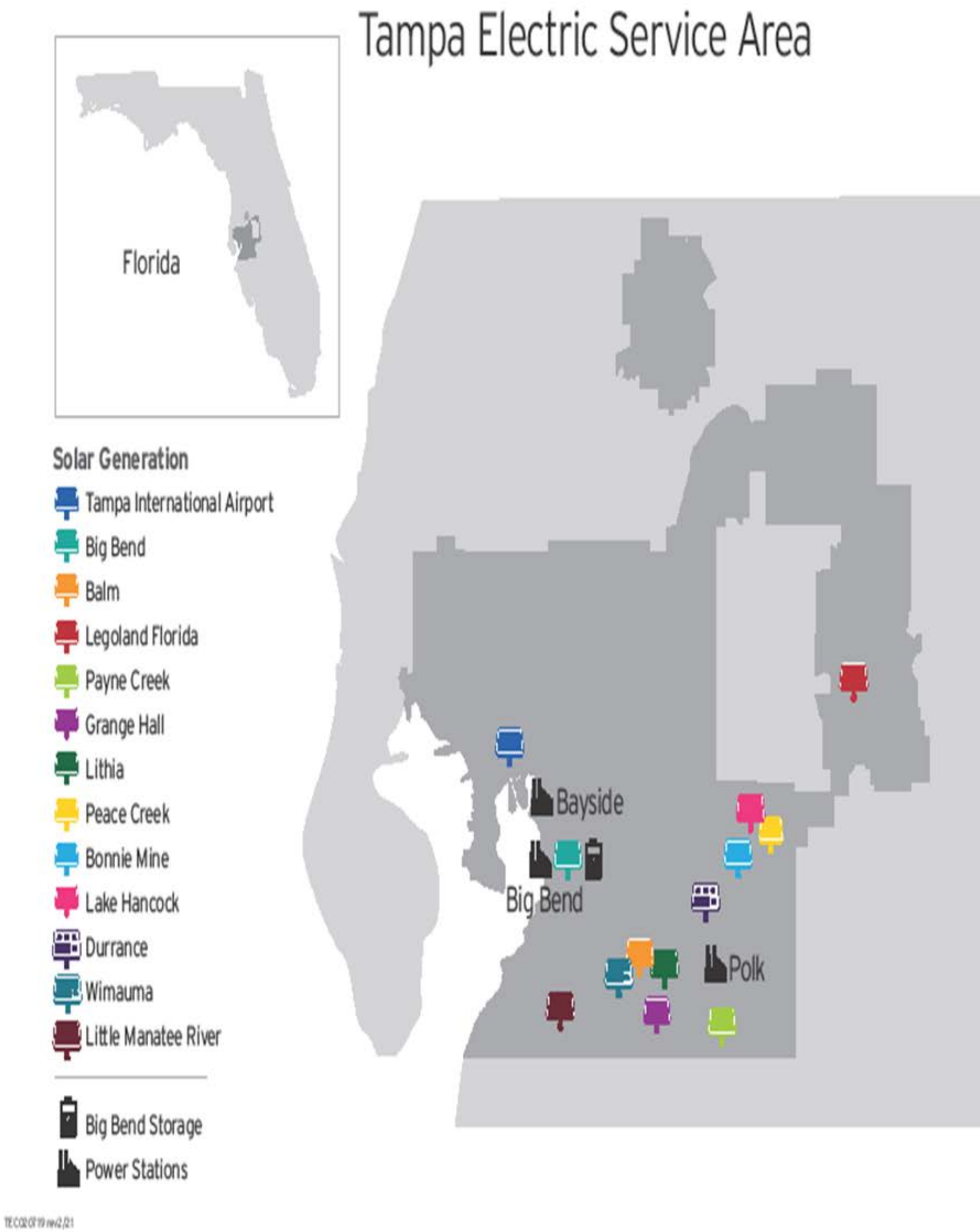
*** Plant firm net capability will be limited effective January 2023

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

***** Approximately 54.1% of Solar generation is considered firm for Summer Reserve Margin and 0% is considered firm for Winter Reserve Margin calculation. Rating for Solar units are nameplate ratings.

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

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 2021-2030 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the 2021-2030 time period.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2021-2030 customer, demand and energy forecasts. This software allows a platform for the development of more dynamic and fully integrated models.

In addition, TEC uses MetrixLT, which integrates with MetrixND, to develop multiple-year forecasts of energy usage at the hourly level. This tool allows the annual or monthly forecasts in MetrixND to be combined with hourly load shape data to develop a long-term "bottom-up" forecast that is consistent with short-term statistical forecasts.

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

1. Economic Analysis
2. Customer Multiregression Model
3. Energy Multiregression Model
4. Peak Demand Multiregression Model
5. Interruptible Demand and Energy Analysis
6. 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 effects of photovoltaic (PV) and electric vehicle (EV) related energy and demand. Likewise, the effects of TEC's conservation, load management, and cogeneration programs are incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

1. Economic Analysis

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

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

2. Customer Multiregression Model

The customer multiregression forecasting model is a nine-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 (Model #1):*** Customer projections are a function of regional population. Since a strong correlation exists between regional population and historical changes in service area customers, regional population estimates were used to forecast the future growth patterns in residential customers.

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

    - The <u>Commercial Customer Model</u> (Model #2) is a function of population. An increase in the number of households provides the need for additional services, restaurants, and retail establishments. The amount of residential activity also plays a part in the attractiveness of the Tampa Bay area as a place to relocate or start a new business.

    - 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> (Model #3) projects the number of customers as a function of new construction permits.

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

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

- The General Service Demand Customer Model (Model #5) is a function of Hillsborough County employment in the manufacturing sector as well as recent trends.

- ***Public Authority Customer Model:*** Customer projections are based on the recent growth trends in the governmental sector and are modeled individually for three rate classes: Residential Service, General Service and General Service Demand. Starting in 2017, street and highway lighting data was included as part of the public authority sector.

  - The Residential Service Customer Model (Model #6) is a function of recent trends.

  - The General Service Customer Model (Model #7) is a function of recent trends.

  - The General Service Demand Customer Model (Model #8) is a function of recent trends, as well.

- ***Street & Highway Lighting Customer Model (Model #9):*** Customer projections are based on recent growth trends in the sector.

3. Energy Multiregression Model

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

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

- ***Residential Energy Model (Model #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:

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

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

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

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

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

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

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

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

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

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

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

- ***Commercial Energy Model:*** total commercial energy sales include commercial sales plus construction service sales; therefore, two models are used to forecast total commercial energy sales.

    - Commercial Energy Model (Model #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 (Model #3): This model is a subset of the total commercial sector and is a rather small percentage of the total commercial sector. Although small in nature, it is still a component that needs to be included. A simple regression model is used with the primary driver being construction service customer growth along with the number of days billed, cooling and heating degree-days.

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

    - The General Service Energy Model (Model #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 (Model #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.

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

    - The Residential Service Energy Model (Model #6) is based on the residential equipment saturation and efficiency assumptions used in the residential model.

    - The General Service Energy Model (Model #7) 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 (Model #8) is a function of cooling and heating degree-days.

- ***Street & Highway Lighting Sector Energy Model (Model #9):*** The street and highway lighting sector is not weather sensitive; therefore, it is a rather simple model and the SAE modeling approach does not apply. The model is a linear regression model where street and highway lighting energy consumption is a function of the number of billing days in the cycle, the number of daylight hours in a day for each month, and recent trends. Starting in 2017, street and highway lighting data was included as part of the public authority sector. The street and highway lighting forecast reflects the impacts of the company's LED lighting program.

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

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

4. Peak Demand Multiregression Model

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

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

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

5. Interruptible Demand and Energy Analysis

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

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

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

6. Roof Top Solar (PV)

Roof top 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, assumptions on future incremental PV installations and the amount of generation they can produce are developed and accumulated to produce a forecast of PV generation. It is assumed that 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

The electric vehicle 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 a number of assumptions including the average number of miles driven in a year, the weighted average battery size of four 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 2020, Tampa Electric continued operating within the 2015-2024 DSM Plan and transitioned to the FSPC approved 2020-2029 DSM Plan on November 2, 2020 supporting the approved FPSC goals, which are reasonable, beneficial and cost-effective to all customers as required by the FEECA. The 2020-2029 DSM Plan included the addition of seven new DSM programs and the discontinuation of two residential and seven commercial existing DSM programs. The following is a list that briefly describes the company's DSM programs, including noting the new and discontinued 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. Residential Electronically Commutated Motor (ECM) – a rebate program that encourages residential customers to replace their existing HVAC air handler motor with an ECM. This program was discontinued on November 2, 2020.

5. Energy 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.

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

7. Energy Star for New Homes - a rebate program that encourages residential customers to construct residential dwellings that qualify for the Energy Star Award by achieving efficiency levels greater than current Florida building code baseline practices.

8. Energy Star Pool Pumps - a rebate program that encourages residential customers to install Energy Star rated pool pumps in existing homes. This program was started on November 2, 2020.

9. Energy Star Thermostats - a rebate program that encourages residential customers to install Energy Star rated thermostats in existing homes. This program was started on November 2, 2020.

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

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

12. 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 will use the company's advanced metering infrastructure ("AMI") system. Once the company completes the AMI system and it becomes fully available, this program will start.

13. 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.

14. Residential Wall Insulation – a rebate program that encourages existing residential customers to install additional wall insulation in existing homes. This program was discontinued on November 2, 2020.

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

16. Commercial Ceiling Insulation – a rebate program that encourages commercial and industrial customers to install additional ceiling insulation in existing commercial structures. This program was discontinued on November 2, 2020.

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

18. 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.

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

20. Cool Roof – a rebate program that encourages commercial and industrial customers to install a cool roof system above conditioned spaces. This program was discontinued on November 2, 2020.

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

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

23. Commercial Duct Repair – a rebate program that encourage existing commercial and industrial customers to repair leaky ductwork of central air-conditioning systems in existing commercial and industrial facilities. This program was discontinued on November 2, 2020.

24. Commercial Electronically Commutated Motors (ECM) - a rebate program that encourages commercial and industrial customers to replace their existing air handler motors or refrigeration fan motors with an ECM. This program was discontinued on November 2, 2020.

25. Commercial Facility Energy Management System - a rebate program that encourages commercial and industrial customers to install high efficiency energy management systems. This program was started on November 2, 2020.

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

27. 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.

28. 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.

29. 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.

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

31. 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.

32. Refrigeration Anti-Condensate Control – a rebate program that encourages commercial and industrial customers to install anti-condensate equipment sensors and control within refrigerated door systems. This program was discontinued on November 2, 2020.

33. Commercial Smart Thermostat - a rebate program that encourages commercial and industrial customers to smart thermostats. This program was started on November 2, 2020.

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

35. Thermal Energy Storage - a rebate program that encourages commercial and industrial customers to install an off-peak air conditioning system. This program was discontinued on November 2, 2020.

36. 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. This program was started on November 2, 2020.

37. Commercial Wall Insulation – a rebate program that encourages commercial and industrial customers to install wall insulation in existing commercial and industrial structures. This program was discontinued on November 2, 2020.

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

39. 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. This program was started on November 2, 2020.

40. 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 2020 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		8.0			3.3			7.7	
2022		7.4			3.0			6.9	
2023		6.8			2.9			6.3	
2024		6.1			2.5			5.5	

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	8.1	1.2	675.0%	11.7	1.7	688.2%	12.5	3.9	320.5%
2016	2.9	1.3	223.1%	4.4	2.5	176.0%	17.8	6.0	296.7%
2017	9.2	1.6	575.0%	10.4	2.7	385.2%	30.2	8.0	377.5%
2018	13.0	1.7	767.1%	15.0	3.3	453.6%	33.7	9.2	365.9%
2019	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		1.9			3.6			10.4	
2022		1.9			3.3			10.2	
2023		1.8			3.5			9.9	
2024		1.7			3.2			9.6	

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	20.4	3.8	536.8%	22.5	2.8	803.6%	33.7	5.7	591.2%
2016	10.6	5.4	196.3%	9.5	4.1	231.7%	31.0	9.5	326.3%
2017	16.1	6.8	236.8%	15.1	4.9	308.2%	45.1	12.8	352.3%
2018	21.0	8.2	256.5%	20.5	6.0	342.1%	50.8	15.3	331.8%
2019	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		9.9			6.9			18.1	
2022		9.3			6.3			17.1	
2023		8.6			6.4			16.2	
2024		7.8			5.7			15.1	

BASE CASE FORECAST ASSUMPTIONS

RETAIL LOAD

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

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

1. Population and Households

Florida and Hillsborough County population forecasts are the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Moody's Analytics supply population projections for Hillsborough County and Florida comparisons. BEBR's population growth for Hillsborough County was used to project future growth patterns in residential customers for the period of 2021-2030. 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 (2021-2030), employment is assumed to rise at a 2.0% average annual rate within Hillsborough County. Moody's Analytics supplies employment projections for the non-residential models.

3. Commercial, Industrial and Governmental Output

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Output for the entire employment sector within Hillsborough County is assumed to rise at a 3.3% average annual rate from 2021-2030. 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 2021-2030, real household income for Hillsborough County is expected to increase at a 2.5% 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. In addition, the temperature profiles used in projecting the winter and summer system peak are based on an examination of the minimum and maximum temperatures for the past twenty years plus the temperatures on peak days for the past twenty years.

HIGH AND LOW SCENARIO FOCUS ASSUMPTIONS

The base case scenario is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy scenarios represent alternatives to the company's base case outlook. Compared to the base case, the expected economic growth rates are 0.5 percent higher in the high scenario and 0.5 percent lower in the low scenario.

HISTORY AND FORECAST OF ENERGY USE

A history and forecast of energy consumption by customer classification are shown in Schedules 2.1 - 2.3 in Chapter IV.

1. Retail Energy

For 2021-2030, 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 1.1%.

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 2021-2030, TEC's base retail firm peak demand is expected to increase at an average annual rate of 1.1% in the summer and 1.2% in the winter.

Chapter III

INTEGRATED RESOURCE PLANNING PROCESSES

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

The process incorporates a reliability analysis to determine timing of future needs and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. Initially, a demand and energy forecast 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 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 computer model developed by ABB, System Optimizer (SO), to evaluate supply-side resources. SO utilizes a mixed integer linear program (MILP) to develop an estimate of the timing and type of supply-side resources for 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 Planning & Risk (PaR) production cost model, also developed by ABB. 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 enhancements to and retirement of existing assets, the completion of solar PV through 2021 in accordance with the approved 2017 Solar Base Rate Adjustment (SoBRA) agreement, additional future utility-scale solar, battery storage, and reciprocating engines over the next ten years.

The first phase of the Big Bend modernization project will commence with the deployment of two simple cycle CTs and the retirement of Unit 2 in December 2021. The exhaust from these CTs will then be captured and integrated into a modernized Big Bend Unit 1 steam turbine to create a natural gas combined cycle by December of 2022. In addition, the Bayside station will undergo advanced hardware improvements to its existing seven CTs during 2022 and 2023. Big Bend Unit 3 will be retired in April of 2023. All these changes to the expansion plan are shown in Schedule 8.1.

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 natural gas, coal, and oil fuel commodity prices by analyzing current market prices and price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, S&P Scenario Planning Service Annual Guidebook (originally produced by PIRA Energy Group), U.S. Energy Information Administration, S&P Global Market Intelligence, IHS Markit, Argus Coal Daily, Inside FERC, and Platt's Oilgram. For natural gas, coal and oil prices, the company produces both high and low fuel price projections, which represent alternative forecasts to the company's base case outlook.

TEC RENEWABLE RESOURCES AND STORAGE TECHNOLOGY INITIATIVES

1. Renewable Energy Initiatives

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, TEC now has 655 MW_{AC} of solar capacity, which means approximately 7 percent of our energy comes from the sun. The solar energy significantly reduces Tampa Electric's carbon dioxide emissions, reduces the use of potable water and our customers will benefit from zero-fuel cost solar energy for years to come. As part of its strategic transformation to become cleaner and greener, Tampa Electric is launching another significant expansion of solar power.

In February 2020, the Company announced plans to build 600 MW_{AC} of new cost-effective, utility-scale solar PV generating capacity from 2021 through the end of 2023. By 2023, Tampa Electric will have more than 1,255 MW_{AC} of solar power – enough to power more than 200,000 homes – with about 12 percent of our energy produced by the sun. Beyond 2023 there is an additional 600 MW_{AC} of solar PV generating capacity shown in this TYSP that is in the planning and analysis phase and requires further development.

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 portion 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 2020, TEC's Renewable Energy Program has 1,232 customers purchasing over 2,000 blocks of renewable energy each month and there have been over 4,700 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 and two arrays at the Museum of Science and Industry (MOSI). The newest array flanks the entrance sidewalk at MOSI, providing a striking welcome to visitors. This grid-tied system features a bench charging station and a table 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 Demonstration Center (CEDC). The CEDC 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 and various energy storage technologies. A 1 MW_{AC} floating solar pilot project at FCTC is scheduled to be commissioned by end of July 2021. It integrates solar panels onto floats and will demonstrate bi-facial solar panels to increase the energy 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 the floating solar has the potential to decrease the evaporation of potable water and improve the water quality. A 1 MW_{AC} agrivoltaics pilot project at FCTC is scheduled to be operational by the end of 2021. The project is designed to combine renewable energy with agriculture by positioning elevated solar panels over an understory of plants or crops. 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.

2. Storage Technology Initiatives

Battery storage costs have declined over the last few years and are projected to continue to decline in the future. In December 2019, a 12.6 MW, 25 MWh lithium-ion energy storage system (ESS) was put in service at TEC's Big Bend Solar site. The ESS is integrated with the solar array and will charge via solar energy produced at the site and is discharged to the grid at times when our system is peaking or when solar production is reduced or unavailable. Expected benefits of battery storage projects include firming of the solar output during peak times and contribution to contingency reserves. TEC expects to develop and deploy approximately 300 MW of various types of energy storage systems from 2024 through 2030 to meet system reliability needs, maximize solar energy production by minimize solar clipping during low system peak periods, and potentially avoid transmission and distribution investments.

GENERATING UNIT PERFORMANCE ASSUMPTIONS

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

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

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

GENERATION RELIABILITY CRITERIA

TEC calculates reserve margin in two ways to measure reliability of the generating system. The company utilizes a minimum 20 percent firm reserve margin with a minimum contribution of 7 percent supply-side resources. TEC's approach to calculating percent reserves are consistent with the agreement that is outlined in the Commission approved Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, issued December 22, 1999. The calculation of the minimum 20 percent firm reserve margin employs an industry accepted method of using total available generating capacity and firm purchased power capacity (capacity less planned maintenance and solar capacity unavailable at the time of peak demand, and contracted unit sales) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100. Capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from TEC's available capacity.

TEC's supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the firm peak demand and interruptible and load management loads.

SUPPLY-SIDE RESOURCES PROCUREMENT PROCESS

TEC 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/TransmissionTariff.pdf, as well as the principles contained in the NERC Reliability Standards relating to ATC calculations. Members of the FRCC, including TEC, have formed the Florida Transmission Capability Determination Group in an effort to provide ATC values to the regional electric market that are transparent, coordinated, timely and accurate.

TRANSMISSION SYSTEM PLANNING ASSESSMENT PRACTICES

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

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

1. Base Case Operating Conditions

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

2. Single Contingency Planning Criteria

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

3. Multiple Contingency Planning Criteria

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

4. Transmission Construction and Upgrade Plans

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

ENERGY EFFICIENCY, CONSERVATION, AND ENERGY SAVINGS DURABILITY

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

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

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

3. Analysis of DOE2 modeling of various program participants.

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

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

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

Chapter IV

FORECAST OF ELECTRIC POWER, DEMAND AND ENERGY CONSUMPTION

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

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

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

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

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

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

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

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

Schedule 5: History and Forecast of Fuel Requirements

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

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

Schedule 2.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2011	1,238,951	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,256,118	2.6	8,395	603,594	13,909	6,185	71,143	86,937
2013	1,276,410	2.6	8,470	613,206	13,812	6,090	71,966	84,619
2014	1,301,887	2.6	8,656	623,846	13,875	6,142	72,647	84,548
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
2016	1,352,797	2.5	9,187	646,221	14,217	6,310	74,313	84,911
2017	1,379,302	2.6	9,029	659,387	13,693	6,362	74,998	84,830
2018	1,408,864	2.6	9,418	670,517	14,046	6,266	74,895	83,664
2019	1,444,870	2.6	9,584	685,122	13,989	6,239	76,038	82,057
2020	1,478,759	2.6	10,122	698,493	14,491	6,058	76,790	78,891
2021	1,507,671	2.6	9,698	710,565	13,648	6,123	77,160	79,356
2022	1,535,839	2.6	9,708	722,797	13,431	6,316	77,855	81,120
2023	1,563,076	2.6	9,864	734,626	13,427	6,369	78,464	81,173
2024	1,589,311	2.6	10,007	746,020	13,414	6,415	79,002	81,200
2025	1,614,439	2.5	10,118	756,932	13,367	6,450	79,497	81,129
2026	1,638,038	2.5	10,229	767,181	13,333	6,478	79,947	81,027
2027	1,660,716	2.5	10,347	777,030	13,316	6,505	80,373	80,940
2028	1,682,533	2.5	10,480	786,505	13,325	6,537	80,788	80,914
2029	1,703,547	2.5	10,619	795,630	13,347	6,568	81,194	80,895
2030	1,723,558	2.5	10,741	804,321	13,354	6,599	81,591	80,875

Notes:
December 31, 2020 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
2021	1,522,467	2.6	9,757	713,776	13,670	6,136	77,307	79,370
2022	1,558,523	2.6	9,828	729,358	13,474	6,342	78,157	81,149
2023	1,593,956	2.6	10,048	744,671	13,494	6,410	78,927	81,218
2024	1,628,679	2.6	10,258	759,677	13,503	6,471	79,631	81,262
2025	1,662,572	2.6	10,437	774,325	13,478	6,521	80,298	81,209
2026	1,697,171	2.6	10,618	788,421	13,468	6,565	80,924	81,125
2027	1,730,465	2.6	10,809	802,227	13,474	6,609	81,533	81,055
2028	1,763,075	2.6	11,018	815,765	13,507	6,657	82,135	81,048
2029	1,795,053	2.6	11,235	829,056	13,551	6,705	82,734	81,047
2030	1,826,447	2.6	11,436	842,005	13,582	6,753	83,326	81,048

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
2021	1,492,948	2.6	9,638	707,354	13,626	6,110	77,012	79,341
2022	1,513,376	2.6	9,589	716,269	13,387	6,289	77,554	81,090
2023	1,532,648	2.5	9,683	724,679	13,361	6,328	78,006	81,128
2024	1,550,709	2.5	9,761	732,561	13,325	6,360	78,382	81,138
2025	1,567,473	2.5	9,807	739,878	13,255	6,380	78,712	81,049
2026	1,582,548	2.4	9,852	746,456	13,199	6,393	78,992	80,930
2027	1,596,545	2.4	9,903	752,565	13,159	6,405	79,246	80,825
2028	1,609,537	2.4	9,967	758,235	13,145	6,421	79,485	80,781
2029	1,621,591	2.4	10,035	763,495	13,143	6,436	79,715	80,740
2030	1,632,531	2.4	10,085	768,270	13,127	6,450	79,930	80,702

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
2011	1,804	1,494	1,207,299	0	74	1,761	18,564
2012	2,001	1,537	1,302,171	0	75	1,756	18,412
2013	2,027	1,564	1,295,916	0	75	1,756	18,418
2014	1,901	1,572	1,208,831	0	75	1,752	18,526
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	2,024	1,608	1,259,094	0	0	1,771	19,186
2018	2,014	1,588	1,268,262	0	0	1,933	19,631
2019	2,021	1,516	1,332,913	0	0	1,939	19,783
2020	1,891	1,408	1,342,409	0	0	1,883	19,954
2021	1,853	1,400	1,323,864	0	0	1,880	19,553
2022	1,833	1,402	1,307,491	0	0	1,920	19,776
2023	1,815	1,403	1,293,687	0	0	1,931	19,980
2024	1,763	1,404	1,255,810	0	0	1,946	20,131
2025	1,763	1,403	1,256,164	0	0	1,961	20,292
2026	1,763	1,403	1,256,394	0	0	1,976	20,446
2027	1,763	1,403	1,256,964	0	0	1,992	20,607
2028	1,764	1,402	1,257,906	0	0	2,007	20,788
2029	1,764	1,401	1,258,929	0	0	2,022	20,973
2030	1,765	1,401	1,260,039	0	0	2,037	21,141

Notes:
December 31, 2020 Status
*Average of end-of-month customers for the calendar year.
**Sales shown for Street and Highway Lighting from 2017 forward are now included with Other Sales to Public Authorities.
Values shown may be affected due to rounding.

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				Street &	Other Sales	Total Sales
			Average KWH	Railroads	Highway	to Public	to Ultimate
			Consumption	and Railways	Lighting	Authorities	Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH **	GWH	GWH
2021	1,854	1,400	1,324,175	0	0	1,880	19,627
2022	1,835	1,402	1,308,531	0	0	1,920	19,924
2023	1,818	1,404	1,294,843	0	0	1,931	20,208
2024	1,766	1,404	1,258,042	0	0	1,947	20,442
2025	1,768	1,404	1,258,947	0	0	1,962	20,687
2026	1,768	1,404	1,259,533	0	0	1,977	20,928
2027	1,770	1,404	1,260,333	0	0	1,992	21,179
2028	1,771	1,403	1,262,343	0	0	2,007	21,453
2029	1,773	1,403	1,263,488	0	0	2,022	21,735
2030	1,774	1,402	1,265,584	0	0	2,037	22,002

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	Railroads	Highway	to Public	to Ultimate
			Consumption	and Railways	Lighting	Authorities	Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH **	GWH	GWH
2021	1,852	1,399	1,323,914	0	0	1,880	19,480
2022	1,831	1,401	1,306,975	0	0	1,920	19,628
2023	1,813	1,403	1,291,954	0	0	1,931	19,755
2024	1,759	1,403	1,253,810	0	0	1,946	19,827
2025	1,759	1,403	1,253,419	0	0	1,961	19,907
2026	1,758	1,402	1,253,602	0	0	1,976	19,979
2027	1,757	1,401	1,253,988	0	0	1,991	20,056
2028	1,757	1,401	1,253,771	0	0	2,006	20,151
2029	1,756	1,400	1,254,475	0	0	2,022	20,249
2030	1,756	1,399	1,255,218	0	0	2,037	20,328

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
2011	93	642	19,298	7,869	675,799
2012	69	839	19,320	7,962	684,236
2013	0	760	19,177	7,999	694,735
2014	0	789	19,315	8,095	706,161
2015	0	1,098	20,105	8,168	718,713
2016	9	930	20,173	8,353	730,503
2017	2	1,110	20,298	8,698	744,690
2018	0	1,031	20,662	9,254	756,254
2019	0	986	20,770	9,283	771,960
2020	0	1,101	21,055	9,356	786,047
2021	0	971	20,525	9,455	798,579
2022	0	985	20,760	9,538	811,592
2023	0	995	20,975	9,622	824,116
2024	0	1,003	21,134	9,708	836,133
2025	0	1,011	21,302	9,794	847,627
2026	0	1,019	21,465	9,881	858,412
2027	0	1,027	21,634	9,968	868,773
2028	0	1,036	21,823	10,056	878,751
2029	0	1,045	22,018	10,144	888,371
2030	0	1,054	22,195	10,233	897,545

Notes:

December 31, 2020 Status

*Includes sales to Duke Energy Florida (DEF), Wauchula (WAU), Ft. Meade (FTM), St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL). Contract ended with DEF on 2/31/11, WAU on 9/31/11, STC on 12/31/2012, and FPL on 12/31/12. 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
2021	0	975	20,602	9,455	801,938
2022	0	992	20,916	9,538	818,455
2023	0	1,006	21,214	9,622	834,624
2024	0	1,018	21,460	9,708	850,420
2025	0	1,030	21,717	9,794	865,821
2026	0	1,043	21,971	9,881	880,630
2027	0	1,055	22,234	9,968	895,132
2028	0	1,069	22,522	10,056	909,359
2029	0	1,083	22,818	10,144	923,337
2030	0	1,096	23,098	10,233	936,966

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
2021	0	968	20,448	9,455	795,220
2022	0	978	20,606	9,538	804,762
2023	0	984	20,739	9,622	813,710
2024	0	987	20,814	9,708	822,054
2025	0	991	20,898	9,794	829,787
2026	0	996	20,975	9,881	836,731
2027	0	1,000	21,056	9,968	843,180
2028	0	1,004	21,155	10,056	849,177
2029	0	1,009	21,258	10,144	854,754
2030	0	1,013	21,341	10,233	859,832

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)	(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
2011	4,130	28	4,102	109	48	103	75	68	3,699
2012	4,089	15	4,073	133	45	111	86	71	3,627
2013	4,072	0	4,072	131	39	122	89	77	3,614
2014	4,270	0	4,270	170	36	132	91	83	3,757
2015	4,245	0	4,245	111	21	143	98	87	3,784
2016	4,403	15	4,388	138	0	150	101	92	3,907
2017	4,373	5	4,368	110	0	155	100	98	3,905
2018	4,287	0	4,287	125	0	160	98	106	3,798
2019	4,591	0	4,591	122	0	166	98	126	4,079
2020	4,568	0	4,568	113	0	169	98	135	4,053
2021	4,492	0	4,492	113	0	177	104	144	3,953
2022	4,552	0	4,552	108	0	183	105	149	4,007
2023	4,612	0	4,612	106	0	189	105	154	4,058
2024	4,664	0	4,664	99	0	195	105	159	4,106
2025	4,715	0	4,715	99	0	201	106	164	4,146
2026	4,766	0	4,766	99	0	206	106	169	4,186
2027	4,817	0	4,817	99	0	212	106	174	4,226
2028	4,869	0	4,869	99	0	218	107	178	4,267
2029	4,921	0	4,921	99	0	224	107	183	4,308
2030	4,970	0	4,970	99	0	229	107	188	4,346

Notes:
December 31, 2020 Status
2016, 2018 and 2020 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12 and FP&L on 12/31/12.
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) 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
2021	4,509	0	4,509	113	0	177	104	144	3,970
2022	4,586	0	4,586	108	0	183	105	149	4,041
2023	4,664	0	4,664	106	0	189	105	154	4,111
2024	4,734	0	4,734	99	0	195	105	159	4,176
2025	4,805	0	4,805	99	0	201	106	164	4,236
2026	4,875	0	4,875	99	0	206	106	169	4,295
2027	4,946	0	4,946	99	0	212	106	174	4,355
2028	5,019	0	5,019	99	0	218	107	178	4,417
2029	5,092	0	5,092	99	0	224	107	183	4,479
2030	5,164	0	5,164	99	0	229	107	188	4,540

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
2021	4,476	0	4,476	113	0	177	104	144	3,937
2022	4,519	0	4,519	108	0	183	105	149	3,974
2023	4,561	0	4,561	106	0	189	105	154	4,008
2024	4,595	0	4,595	99	0	195	105	159	4,037
2025	4,629	0	4,629	99	0	201	106	164	4,060
2026	4,660	0	4,660	99	0	206	106	169	4,080
2027	4,692	0	4,692	99	0	212	106	174	4,101
2028	4,724	0	4,724	99	0	218	107	178	4,122
2029	4,757	0	4,757	99	0	224	107	183	4,144
2030	4,786	0	4,786	99	0	229	107	188	4,162

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
2010/11	4,697	122	4,575	140	88	480	75	58	3,735
2011/12	4,186	120	4,066	103	68	487	83	58	3,267
2012/13	3,780	15	3,764	130	65	501	90	61	2,918
2013/14	3,876	0	3,876	61	63	512	97	64	3,079
2014/15	4,195	0	4,195	79	44	521	96	65	3,390
2015/16	4,025	0	4,025	145	13	533	96	67	3,171
2016/17	3,749	0	3,749	137	0	541	96	70	2,905
2017/18	4,670	0	4,670	66	0	548	96	77	3,883
2018/19	3,921	0	3,921	104	0	556	98	92	3,071
2019/20	4,237	0	4,237	140	0	564	97	99	3,336
2020/21	5,096	0	5,096	112	0	572	100	124	4,188
2021/22	5,177	0	5,177	107	0	581	101	132	4,256
2022/23	5,252	0	5,252	105	0	589	101	140	4,317
2023/24	5,315	0	5,315	98	0	597	102	143	4,375
2024/25	5,377	0	5,377	98	0	605	103	145	4,426
2025/26	5,434	0	5,434	98	0	613	103	147	4,473
2026/27	5,490	0	5,490	98	0	621	104	149	4,518
2027/28	5,548	0	5,548	98	0	629	104	151	4,565
2028/29	5,605	0	5,605	98	0	637	105	154	4,611
2029/30	5,660	0	5,660	98	0	645	105	156	4,656

Notes:
December 31, 2020 Status
2011/2012 and 2015/2016 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12 and FP&L on 12/31/12.
Contract with RCID from 2016 to 2017.
***Includes Eenergy Planner program.
Values shown may be affected due to rounding.

Schedule 3.2

Forecast of Winter Peak Demand (MW)
High Case

(1) Year	(2) Total *	(3) Wholesale	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation**	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2020/21	5,114	0	5,114	112	0	572	100	124	4,206
2021/22	5,212	0	5,212	107	0	581	101	132	4,292
2022/23	5,307	0	5,307	105	0	589	101	140	4,371
2023/24	5,388	0	5,388	98	0	597	102	143	4,449
2024/25	5,472	0	5,472	98	0	605	103	145	4,522
2025/26	5,550	0	5,550	98	0	613	103	147	4,589
2026/27	5,627	0	5,627	98	0	621	104	149	4,655
2027/28	5,707	0	5,707	98	0	629	104	151	4,724
2028/29	5,787	0	5,787	98	0	637	105	154	4,793
2029/30	5,865	0	5,865	98	0	645	105	156	4,861

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
2020/21	5,078	0	5,078	112	0	572	100	124	4,170
2021/22	5,141	0	5,141	107	0	581	101	132	4,221
2022/23	5,199	0	5,199	105	0	589	101	140	4,263
2023/24	5,241	0	5,241	98	0	597	102	143	4,302
2024/25	5,284	0	5,284	98	0	605	103	145	4,334
2025/26	5,322	0	5,322	98	0	613	103	147	4,361
2026/27	5,358	0	5,358	98	0	621	104	149	4,386
2027/28	5,395	0	5,395	98	0	629	104	151	4,412
2028/29	5,430	0	5,430	98	0	637	105	154	4,436
2029/30	5,464	0	5,464	98	0	645	105	156	4,460

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 %
2011	19,296	474	259	18,564	93	642	19,298	53.0
2012	19,178	493	273	18,412	69	839	19,320	56.3
2013	19,225	513	294	18,418	0	760	19,177	56.5
2014	19,377	546	305	18,526	0	789	19,315	54.4
2015	19,890	568	315	19,006	0	1,098	20,105	57.2
2016	20,153	588	331	19,234	9	930	20,173	55.2
2017	20,141	602	353	19,186	2	1,110	20,298	56.2
2018	20,647	618	399	19,631	0	1,031	20,662	58.3
2019	20,896	635	478	19,783	0	986	20,770	55.2
2020	21,085	644	487	19,954	0	1,101	21,055	56.2
2021	20,798	664	581	19,553	0	971	20,525	53.2
2022	21,072	677	619	19,776	0	985	20,760	53.1
2023	21,314	691	643	19,980	0	995	20,975	52.9
2024	21,490	705	654	20,131	0	1,003	21,134	52.6
2025	21,674	719	664	20,292	0	1,011	21,302	52.6
2026	21,853	732	675	20,446	0	1,019	21,465	52.4
2027	22,038	746	685	20,607	0	1,027	21,634	52.3
2028	22,243	760	696	20,788	0	1,036	21,823	52.1
2029	22,453	773	707	20,973	0	1,045	22,018	52.2
2030	22,646	787	717	21,141	0	1,054	22,195	52.1

Notes:
December 31, 2020 Status
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
***Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12 and FP&L on 12/31/12. Contract with RCID from 2016 to 2017.
****Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

Schedule 3.3

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total*	Residential Conservation**	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load *** Factor %
2021	20,872	664	581	19,627	0	975	20,602	53.2
2022	21,220	677	619	19,924	0	992	20,916	53.1
2023	21,542	691	643	20,208	0	1,006	21,214	52.9
2024	21,800	705	654	20,442	0	1,018	21,460	52.6
2025	22,069	719	664	20,687	0	1,030	21,717	52.5
2026	22,335	732	675	20,928	0	1,043	21,971	52.4
2027	22,610	746	685	21,179	0	1,055	22,234	52.3
2028	22,909	760	696	21,453	0	1,069	22,522	52.1
2029	23,215	773	707	21,735	0	1,083	22,818	52.1
2030	23,506	787	717	22,002	0	1,096	23,098	52.1

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

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 %**
2021	20,725	664	581	19,480	0	968	20,448	53.3
2022	20,924	677	619	19,628	0	978	20,606	53.1
2023	21,089	691	643	19,755	0	984	20,739	53.0
2024	21,185	705	654	19,827	0	987	20,814	52.6
2025	21,289	719	664	19,907	0	991	20,898	52.6
2026	21,386	732	675	19,979	0	996	20,975	52.5
2027	21,488	746	685	20,056	0	1,000	21,056	52.4
2028	21,607	760	696	20,151	0	1,004	21,155	52.2
2029	21,729	773	707	20,249	0	1,009	21,258	52.3
2030	21,833	787	717	20,328	0	1,013	21,341	52.2

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)
	2020 Actual		2021 Forecast		2022 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,538	1,494	4,400	1,498	4,464	1,517
February	3,013	1,423	3,598	1,338	3,647	1,346
March	3,574	1,636	3,453	1,454	3,505	1,472
April	3,591	1,588	3,510	1,572	3,551	1,589
May	3,903	1,786	3,794	1,828	3,839	1,858
June	4,254	2,013	4,080	1,966	4,131	1,992
July	4,143	2,128	4,087	2,047	4,138	2,072
August	4,239	2,097	4,170	2,078	4,220	2,108
September	4,255	1,942	3,859	1,955	3,907	1,963
October	3,872	1,880	3,626	1,789	3,666	1,812
November	3,274	1,539	3,069	1,452	3,107	1,468
December	3,024	1,529	3,742	1,548	3,788	1,563
TOTAL		21,055		20,525		20,760

Notes:
December 31, 2020 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)
	2020 Actual		2021 Forecast		2022 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,538	1,494	4,418	1,504	4,500	1,528
February	3,013	1,423	3,613	1,343	3,676	1,356
March	3,574	1,636	3,466	1,459	3,532	1,482
April	3,591	1,588	3,524	1,577	3,580	1,600
May	3,903	1,786	3,809	1,835	3,869	1,872
June	4,254	2,013	4,097	1,974	4,164	2,007
July	4,143	2,128	4,103	2,055	4,171	2,088
August	4,239	2,097	4,187	2,086	4,254	2,125
September	4,255	1,942	3,874	1,962	3,938	1,978
October	3,872	1,880	3,640	1,796	3,695	1,826
November	3,274	1,539	3,080	1,457	3,131	1,479
December	3,024	1,529	3,756	1,554	3,817	1,575
TOTAL		21,056		20,602		20,916

Notes:
December 31, 2020 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)
	2020 Actual		2021 Forecast		2022 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,538	1,494	4,382	1,493	4,429	1,506
February	3,013	1,423	3,584	1,333	3,618	1,336
March	3,574	1,636	3,439	1,449	3,477	1,462
April	3,591	1,588	3,496	1,566	3,524	1,578
May	3,903	1,786	3,779	1,821	3,808	1,844
June	4,254	2,013	4,064	1,959	4,099	1,977
July	4,143	2,128	4,071	2,039	4,106	2,056
August	4,239	2,097	4,154	2,070	4,187	2,092
September	4,255	1,942	3,844	1,947	3,876	1,947
October	3,872	1,880	3,612	1,782	3,637	1,798
November	3,274	1,539	3,057	1,447	3,084	1,458
December	3,024	1,529	3,728	1,543	3,759	1,552
TOTAL		21,056		20,449		20,606

Notes:
December 31, 2020 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 Requir	**Unit**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	570	434	543	518	301	231	189	221	283	265	232	222
(3)	Residual	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)	CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)	GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)	D	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	1000 BBL	0	4	0	0	0	0	0	0	0	0	0	0
(9)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)	CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)	GT	1000 BBL	0	4	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	137,874	127,841	126,123	130,968	119,052	119,138	118,396	118,521	117,026	117,692	117,617	118,312
(14)	ST	1000 MCF	31,564	25,422	10,849	5,816	1,759	416	353	403	478	439	426	395
(15)	CC	1000 MCF	106,021	101,977	112,509	123,030	115,809	117,157	117,253	117,373	115,061	116,126	116,296	117,621
(16)	GT	1000 MCF	289	442	2,765	2,122	1,484	1,565	790	745	1,487	1,127	895	296
(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 2019	Actual 2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
(1)	Annual Firm Interchange	GWh	0	1,175	963	0	0	0	0	0	0	0	0	0
(2)	Nuclear	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal	GWh	1,214	909	938	894	520	397	326	382	492	470	404	393
(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	1	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	1	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	17,493	16,514	16,959	17,678	17,605	17,554	17,493	17,574	17,299	17,500	17,470	17,660
(15)	ST	GWh	2,632	2,163	862	483	137	21	17	20	26	25	21	21
(16)	CC	GWh	14,836	14,313	15,868	17,020	17,355	17,406	17,416	17,494	17,147	17,381	17,373	17,617
(17)	GT	GWh	25	38	229	175	113	127	60	60	126	94	76	22
(18)	Renewable	GWh	756	1,120	1,594	2,118	2,631	2,978	3,298	3,303	3,625	3,633	3,949	3,951
(19)	Solar	GWh	756	1,120	1,594	2,118	2,631	2,978	3,298	3,303	3,625	3,633	3,949	3,951
(20)	Other (Specify)													
(21)	PC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(22)	Net Interchange	GWh	1,085	1,202	(37)	(18)	(19)	(33)	(25)	(29)	(15)	(11)	(32)	(36)
(23)	Purchased Energy from Non-Utility Generators	GWh	220	133	108	88	238	238	210	238	238	238	238	238
(24)	Other	GWh	0	0	0	0	0	0	0	(2)	(5)	(7)	(10)	(11)
(25)	Net Energy for Load	GWh	20,770	21,055	20,525	20,760	20,975	21,134	21,302	21,465	21,634	21,823	22,018	22,195

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

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 2019**	**Actual 2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
(1)	**Annual Firm Interchange**	%	0.0	5.6	4.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(2)	**Nuclear**	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	**Coal**	%	5.8	4.3	4.6	4.3	2.5	1.9	1.5	1.8	2.3	2.2	1.8	1.8
(4)	**Residual**	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)	**ST**	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)	**CC**	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	**GT**	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	**D**	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	**Distillate**	%	0.0	0.01	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**	%	84.2	78.4	82.6	85.2	83.9	83.1	82.1	81.9	80.0	80.2	79.3	79.6
(15)	**ST**	%	12.7	10.3	4.2	2.3	0.7	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(16)	**CC**	%	71.4	68.0	77.3	82.0	82.7	82.4	81.8	81.5	79.3	79.6	78.9	79.4
(17)	**GT**	%	0.1	0.2	1.1	0.8	0.5	0.6	0.3	0.3	0.6	0.4	0.3	0.1
(18)	**Renewable**	%	3.6	5.3	7.8	10.2	12.5	14.1	15.5	15.4	16.8	16.6	17.9	17.8
(19)	**Solar**	%	3.6	5.3	7.8	10.2	12.5	14.1	15.5	15.4	16.8	16.6	17.9	17.8
(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**	%	5.2	5.7	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.2)
(23)	**Purchased Energy from Non-Utility Generators**	%	1.1	0.6	0.5	0.4	1.1	1.1	1.0	1.1	1.1	1.1	1.1	1.1
(24)	**Other**	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
(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

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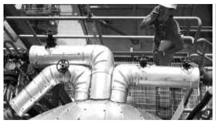
Chapter V



FORECAST OF FACILITIES REQUIREMENTS

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

The results of the IRP process provide TEC with a cost-effective plan that maintains system reliability and environmental requirements while considering technology, availability, 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. By the end of 2023, TEC will add an incremental 600 MW_{AC} of utility-scale solar PV capacity, and is researching the viability of additional renewable technologies. The modernization of the Big Bend Power Station 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.

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 2021, TEC plans for 265 MW of cogeneration capacity operating in its service area.

Table IV-I 2021 Cogeneration Capacity Forecast	Capacity (MW)
Self-service [1]	185
Firm to Tampa Electric	0
As-available to Tampa Electric	33
Export to other systems	47
Total	265

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

FIRM INTERCHANGE SALES AND PURCHASES

Currently, TEC has no long-term firm purchase power agreements. The company does have 3 short-term agreements that provide firm capacity through the Winter of 2021. The purchases are for December of 2020 through February 2021, (i) 150 MW from the Florida Municipal Power Agency (FMPA), (ii) 160 MW from Florida Power and Light, and (iii) 100 MW from the Orlando Utilities Commission.

FUEL REQUIREMENTS

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2. TEC currently uses a generation portfolio consisting mainly of solid fuels and natural gas for its energy requirements. TEC has firm transportation contracts with the Florida Gas Transmission Company, Gulfstream Natural Gas System LLC, and Sabal Trail for delivery of natural gas to Big Bend, Bayside, and Polk. As shown in Schedule 6.2, in 2021, coal will fuel 4.6% of the net energy for load, natural gas is expected to fuel 82.6%, and solar is expected to provide 7.8%. The remaining net energy for load is served by firm, non-firm, and non-utility generator purchases. Some of the company's generating units have dual-fuel (i.e., natural gas or oil) capability, which enhances system reliability, resiliency, and provides fuel cost reduction opportunities.

ENVIRONMENTAL CONSIDERATIONS

Air Quality

TEC continually strives to reduce emissions from its generating facilities. Since 2000, TEC greatly reduced annual sulfur dioxides, nitrogen oxides, particulate matter, carbon dioxide and mercury emissions. TEC's major addition of solar generation will continue the company's transformation into a cleaner, more sustainable energy company. TEC's major activities to increase pollution control and decrease emissions include:

- TEC will phase in a modernization of Big Bend through the repowering of Unit 1 by 2023 into a highly efficient combined cycle unit and retiring Unit 2.
- TEC expects to retire Big Bend Unit 3 in April of 2023.
- The Polk Power Station combined-cycle project, which was completed in January 2017, improved system reliability and further reduced emissions system-wide.

The installation of 1,255 megawatts of solar power by 2023 enables the company to significantly reduce its carbon emissions profile and its dependence on carbon-based fuels. Once complete, approximately 12 percent of TEC's energy will be fueled by the sun, reducing carbon dioxide (CO_2) emissions by more than a million tons each year. These projects, as well as best operation and maintenance work practices have reduced CO_2 emissions by more than half compared to 2000 levels.

In January 2021, the ACE rule was vacated, clearing the way for the new EPA Administration to issue a replacement rule regulating CO_2 emissions from existing power plants.

Water Conservation

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 2.66 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.

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

The final Effluent Limitations Guidelines (ELG) were published on November 3, 2015. The ELGs establish limits for wastewater discharges from flue gas desulfurization (FGD) processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals, gasification processes, and flue gas mercury controls. New limits will require new technology at Big Bend Station. Since Polk Power Station discharges gasification wastewater to the onsite deep injection wells rather than to surface water, the limits are not applicable.

Solid Waste

The Coal Combustion Residuals Rule (CCR) became effective on October 19, 2015. The Big Bend Unit #4 Economizer Ash Ponds and the converted Units 1-3 slag fines pond are covered by this rule. The slag pond was cleaned out and lined in 2020 to allow for continued storm water storage. The Economizer Ponds Closure Project is in progress and will be completed in 2021 by removing and disposing of the CCRs offsite and restoring the site to natural grade. The South Gypsum Storage Area Closure Project was completed as a component of the Big Bend Modernization in January 2020. There are no regulated CCR units at Polk or Bayside Power Stations.

Schedule 7.1

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

(1) Year	(2) Total Installed Capacity MW	(3) Firm Capacity Import MW	(4) Firm Capacity Export MW	(5) QF MW	(6) Total Capacity Available MW	(7) System Firm Summer Peak Demand MW	(8) Reserve Margin Before Maintenance MW	(9) % of Peak	(10) Scheduled * Maintenance MW	(11) Reserve Margin After Maintenance MW	(12) % of Peak
2021	5,058	0	0	0	5,058	3,953	1,105	28%	284	821	21%
2022	5,583	0	0	0	5,583	4,007	1,576	39%	410	1,166	29%
2023	5,852	0	0	0	5,852	4,058	1,794	44%	507	1,287	32%
2024	6,090	0	0	0	6,090	4,106	1,985	48%	571	1,414	34%
2025	6,273	0	0	0	6,273	4,146	2,126	51%	635	1,492	36%
2026	6,318	0	0	0	6,318	4,186	2,132	51%	632	1,500	36%
2027	6,513	0	0	0	6,513	4,226	2,287	54%	696	1,591	38%
2028	6,558	0	0	0	6,558	4,267	2,291	54%	694	1,597	37%
2029	6,753	0	0	0	6,753	4,308	2,445	57%	758	1,687	39%
2030	6,797	0	0	0	6,797	4,346	2,452	56%	755	1,697	39%

* Indicates capacity unavailable at time of peak.
Values shown may be affected due to rounding.

Schedule 7.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	% of Peak	Scheduled* Maintenance MW	Reserve Margin After Maintenance MW	% of Peak
2020-21	5,461	410	0	0	5,871	4,188	1,683	40%	637	1,046	25%
2021-22	6,050	0	0	0	6,050	4,256	1,793	42%	921	872	20%
2022-23	6,424	0	0	0	6,424	4,317	2,108	49%	1,141	967	22%
2023-24	6,580	0	0	0	6,580	4,375	2,205	50%	1,286	919	21%
2024-25	6,762	0	0	0	6,762	4,426	2,335	53%	1,431	904	20%
2025-26	6,807	0	0	0	6,807	4,473	2,334	52%	1,426	908	20%
2026-27	7,002	0	0	0	7,002	4,518	2,483	55%	1,571	912	20%
2027-28	7,046	0	0	0	7,046	4,565	2,481	54%	1,566	916	20%
2028-29	7,241	0	0	0	7,241	4,611	2,629	57%	1,710	919	20%
2029-30	7,285	0	0	0	7,285	4,656	2,629	56%	1,704	925	20%

* Indicates capacity unavailable at time of peak.
Values shown may be affected due to rounding.

Schedule 8.1
Planned and Prospective Generating Facility Additions and Changes

(1) 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
2021														
Durrance [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	01/21	*	60,100	33.6	-	P
Mountain View Solar [1]	1	Pasco	PV	SOLAR	NA	NA	NA	-	12/21	*	52,500	29.3	-	P
Magnolia Solar [1]	1	Hillsborough/Polk	PV	SOLAR	NA	NA	NA	-	12/21	*	74,500	41.6	-	P
Big Bend II Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/21	*	25,000	14.0	-	P
Jamison Solar [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/21	*	74,500	41.6	-	P
Big Bend CT 5 [2]	5M	Big Bend	GT	NG	NA	PL	NA	08/19	12/21	*	397,800	360.0	392.0	P
Big Bend CT 6 [2]	6M	Big Bend	GT	NG	NA	PL	NA	08/19	12/21	*	397,800	360.0	392.0	P
Big Bend ST1 Modernization Outage	1	Big Bend	ST	BIT	NG	WA/RR	PL	-	-	1/21	445,500	(385.0)	(395.0)	OT
Big Bend 2 Retirement	2	Big Bend	ST	BIT	NG	WA/RR	PL	-	04/73	12/21	445,500	(385.0)	(395.0)	RT
Solar Degradation[3]	N/A											(2.4)	-	
											2021 Changes and Additions:	107.8	(6.0)	
2022														
Bayside 1 Enhancement	1	Bayside	CC	NG	NA	PL	NA	-	11/22	*	65,000	48.0	65.0	P
Big Bend ST 1	1M	Big Bend	ST	NG	NA	PL	NA	04/20	12/22	*	445,500	335.0	335.0	P
Laurel Oaks Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/22	*	66,800	37.3	-	P
Riverside Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/22	*	65,000	36.3	-	P
Big Bend III Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/22	*	22,200	12.4	-	P
Palm River Dairy Solar [1]	1	Pasco	PV	SOLAR	NA	NA	NA	-	12/22	*	70,000	39.1	-	P
Solar Degradation[3]	N/A											(1.4)	-	
											2022 Changes and Additions:	506.8	400.0	

Schedule 8.1 Cont'd
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
2023														
Bayside 2 Enhancement	2	Bayside	CC	NG	NA	PL	NA	-	11/23	*	80,000	70.0	80.0	P
Alafia Solar [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/23	*	50,000	28.0	-	P
Wheeler Solar [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/23	*	74,500	41.6	-	P
Dover Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/23	*	25,000	14.0	-	P
Big Bend 3 Retirement	1	Big Bend	ST	NG	NG	PL	PL	-	-	04/23	486,000	(395.0)	(400.0)	RT
Solar Degradation[3]	N/A											(1.9)	-	
											2023 Changes and Additions:	(243.3)	(320.0)	
2024														
Reciprocating Engine	1	Unknown	IC	NG	NA	PL	NA	-	12/24	*	37,000	37.0	37.0	P
Future Solar 1 [1,4]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/24	*	150,000	83.9	-	P
Solar Degradation[3]	N/A											(2.4)	-	
											2024 Changes and Additions:	118.5	37.0	
2025														
Battery Storage 1	1	Unknown	BA	N/A	N/A	N/A	N/A	-	12/25	*	50,000	50.0	50.0	P
Solar Degradation[3]	N/A											(2.4)	-	
											2025 Changes and Additions:	47.6	50.0	
2026														
Battery Storage 2	1	Unknown	BA	N/A	N/A	N/A	N/A	-	12/26	*	50,000	50.0	50.0	P
Future Solar 2 [1,4]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/26	*	150,000	83.9	-	P
Solar Degradation[3]	N/A											(2.6)	-	
											2026 Changes and Additions:	131.2	50.0	
2027														
Battery Storage 3	2	Unknown	BA	N/A	N/A	N/A	N/A	-	12/27	*	50,000	50.0	50.0	P
Solar Degradation[3]	N/A											(2.6)	-	
											2027 Changes and Additions:	47.4	50.0	

Schedule 8.1 Cont'd
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
2028														
Battery Storage 4	3	Unknown	BA	N/A	N/A	N/A	N/A	-	12/28	*	50,000	50.0	50.0	P
Future Solar 3 [1,4]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/28	*	150,000	83.9	-	P
Solar Degradation[3]	N/A											(2.8)	-	
											2028 Changes and Additions:	131.1	50.0	
2029														
Battery Storage 5	4	Unknown	BA	N/A	N/A	N/A	N/A	-	12/29	*	50,000	50.0	50.0	P
Solar Degradation[3]	N/A											(2.7)	-	
											2029 Changes and Additions:	47.3	50.0	
2030														
Battery Storage 6	5	Unknown	BA	N/A	N/A	N/A	N/A	-	12/30	*	50,000	50.0	50.0	P
Future Solar 4 [1,4]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/30	*	150,000	83.9	-	P
Solar Degradation[3]	N/A											(2.9)	-	
											2030 Changes and Additions:	130.9	50.0	

Notes:

* Undetermined
1 Solar MW values reflect capacity at time of peak.
2 Net capability will be restricted to 330 MW summer / 350 MW winter until being placed into combined cycle mode in 2023.
3 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.
4 Muliple Sites, each not to exceed 74.5MW

Schedule 9
(Page 1 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Durrance Solar
(2)	Net Capability	
	A. Summer	60.1 MW-ac
	B. Winter	60.1 MW-ac
(3)	Technology Type	Single Axis Tracking & Fixed Tilt PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	April 2020
	B. Commercial In-Service Date	January 2021
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+473 Acres
(9)	Construction Status	In Service
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2021)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,509.86
	Direct Construction Cost ($/kW)	1,458.68
	AFUDC[2] Amount ($/kW)	51.18
	Escalation ($/kW)	N/A
	Fixed O&M (In-Service Year $/kW – Yr)	5.35
	Variable O&M (In-Service Year $/MWh)	0.0
	K-Factor [1]	1.08

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

Schedule 9
(Page 2 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Mountain View Solar
(2)	Net Capability	
	A. Summer	52.5MW-ac
	B. Winter	52.5MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	April 2021
	B. Commercial In-Service Date	December 2021
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+359 Acres
(9)	Construction Status	Under Construction
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2022)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,426.42
	Direct Construction Cost ($/kW)	1,333.01
	AFUDC[2] Amount ($/kW)	93.41
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	10.91
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.10

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

Schedule 9
(Page 3 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Magnolia Solar
(2)	Net Capability	
	A. Summer	74.9MW-ac
	B. Winter	74.9MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	April 2021
	B. Commercial In-Service Date	December 2021
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+577 Acres
(9)	Construction Status	Under Construction
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2022)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost3 (In-Service Year $/kW)	1,243.90
	Direct Construction Cost ($/kW)	1,186.30
	AFUDC[2] Amount ($/kW)	57.60
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	10.91
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.11

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

Schedule 9
(Page 4 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend II Solar
(2)	Net Capability	
	A. Summer	25.0MW-ac
	B. Winter	25.0MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	April 2021
	B. Commercial In-Service Date	December 2021
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+191 Acres
(9)	Construction Status	Under Construction
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2022)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost3 (In-Service Year $/kW)	1,352.46
	Direct Construction Cost ($/kW)	1,352.46
	AFUDC2 Amount ($/kW)	-
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	10.91
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.09

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

Schedule 9
(Page 5 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Jamison Solar
(2)	Net Capability	
	A. Summer	74.5MW-ac
	B. Winter	74.5MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	April 2021
	B. Commercial In-Service Date	December 2021
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+695 Acres
(9)	Construction Status	Under Construction
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2022)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost3 (In-Service Year $/kW)	1,399.96
	Direct Construction Cost ($/kW)	1,335.61
	AFUDC[2] Amount ($/kW)	64.35
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	10.91
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.10

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

Schedule 9
(Page 6 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend CT 5
(2)	Net Capability	
	A. Summer	360MW[4]
	B. Winter	392MW[4]
(3)	Technology Type	Combustion Turbine[3]
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	August 2019
	B. Commercial In-Service Date	December 2021
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	In Progress
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	5%
	Forced Outage Factor (FOF)	2%
	Equivalent Availability Factor (EAF)	93%
	Resulting Capacity Factor (2021)	4.4% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	9,557 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	533.17
	Direct Construction Cost ($/kW)	351.04
	AFUDC[1] Amount ($/kW)	36.37
	Escalation ($/kW)	145.76
	Fixed O&M (In-Service Year $/kW – Yr)	7.32
	Variable O&M (In-Service Year $/MWh)	2.68
	K-Factor	1.56

[1] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection
[3] Converts to 2x1 Combined Cycle with a HRSG & Big Bend ST 1 in 2022
[4] Net capability will be restricted to 330 MW S / 350 MW W until being placed into combined cycle mode in 2022

Schedule 9
(Page 7 of 28)
Status Report and Specifications of Proposed Generating Facilities

Plant Name and Unit Number		Big Bend CT 6
(2)	Net Capability	
	A. Summer	360 MW[3]
	B. Winter	392 MW[3]
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	August 2019
	B. Commercial In-Service Date	November 2021
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	In Progress
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	5%
	Forced Outage Factor (FOF)	2%
	Equivalent Availability Factor (EAF)	93%
	Resulting Capacity Factor (2021)	4.4 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	9,557 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30.00
	Total Installed Cost[2] (In-Service Year $/kW)	533.17
	Direct Construction Cost ($/kW)	351.04
	AFUDC[1] Amount ($/kW)	36.37
	Escalation ($/kW)	145.76
	Fixed O&M (In-Service Year $/kW – Yr)	7.32
	Variable O&M (In-Service Year $/MWh)	2.68
	K-Factor	1.56

[1] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection
[3] Converts to 2x1 Combined Cycle with a HRSG & Big Bend ST 1 in 2022
[4] Net capability will be restricted to 330 MW S / 350 MW W until being placed into combined cycle mode in 2022

Schedule 9
(Page 8 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Bayside 1 Enhancement
(2)	Net Capability	
	A. Summer	48 MW
	B. Winter	65 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	2022
	B. Commercial In-Service Date	November 2022
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2023)	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[2] (In-Service Year $/kW)	375.46
	Direct Construction Cost ($/kW)	367.37
	AFUDC[1] Amount ($/kW)	-
	Escalation ($/kW)	8.10
	Fixed O&M (In-Service Year $/kW – Yr)	-
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	1.43

[1] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection

Schedule 9
(Page 9 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend ST 1
(2)	Net Capability	
	A. Summer	335 MW
	B. Winter	335 MW
(3)	Technology Type	Combined Cycle[3]
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	June 2020
	B. Commercial In-Service Date	December 2022
(5)	Fuel	
	A. Primary Fuel	Waste Heat Recovery
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	SCR, DLN Burners
(7)	Cooling Method	Once Through Cooling
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	In Progress
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	5%
	Forced Outage Factor (FOF)	2%
	Equivalent Availability Factor (EAF)	93%
	Resulting Capacity Factor (2023)	89%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	6,263 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	1,266.28
	Direct Construction Cost ($/kW)	1,037.75
	AFUDC[1] Amount ($/kW)	143.43
	Escalation ($/kW)	85.11
	Fixed O&M (In-Service Year $/kW – Yr)	6.44
	Variable O&M (In-Service Year $/MWh)	2.81
	K-Factor	1.46

[1] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection
[3] Converts Big Bend CT 5 & 6 and HRSG's to 2x1 Combined Cycle

Schedule 9
(Page 10 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Laurel Oaks Solar
(2)	Net Capability	
	A. Summer	66.8MW-ac
	B. Winter	66.8MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	January 2022
	B. Commercial In-Service Date	December 2022
(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	+515 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 (2023)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,268.49
	Direct Construction Cost ($/kW)	1,169.82
	AFUDC[2] Amount ($/kW)	98.67
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.15
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.12

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

Schedule 9
(Page 11 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Riverside Solar
(2)	Net Capability	
	A. Summer	65MW-ac
	B. Winter	65MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	January 2022
	B. Commercial In-Service Date	December 2022
(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	+546 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 (2023)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,336.25
	Direct Construction Cost ($/kW)	1,241.30
	AFUDC[2] Amount ($/kW)	94.95
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.15
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.12

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

Schedule 9
(Page 12 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend III Solar
(2)	Net Capability	
	A. Summer	22.2MW-ac
	B. Winter	22.2MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	January 2022
	B. Commercial In-Service Date	December 2022
(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 (2022)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,274.67
	Direct Construction Cost ($/kW)	1,274.67
	AFUDC[2] Amount ($/kW)	-
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.15
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.11

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

Schedule 9
(Page 13 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Palm River Dairy Solar
(2)	Net Capability	
	A. Summer	70MW-ac
	B. Winter	70MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	January 2022
	B. Commercial In-Service Date	December 2022
(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	+575 Acres
(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)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2022)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,233.78
	Direct Construction Cost ($/kW)	1,183.32
	AFUDC[2] Amount ($/kW)	50.47
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.15
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.13

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

Schedule 9
(Page 14 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Alafia Solar
(2)	Net Capability	
	A. Summer	50MW-ac
	B. Winter	50MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	January 2023
	B. Commercial In-Service Date	December 2023
(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	+408 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 (2023)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,381.71
	Direct Construction Cost ($/kW)	1,251.92
	AFUDC[2] Amount ($/kW)	129.79
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.39
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.12

[1] w/o Land

[2] Based on the current AFUDC rate of 6.46%[3] Total installed cost includes transmission interconnection

[3] Total installed cost includes transmission interconnection

[4] Construction schedule includes engineering design and permitting

Schedule 9
(Page 15 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Wheeler Solar
(2)	Net Capability	
	A. Summer	74.5MW-ac
	B. Winter	74.5MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	January 2023
	B. Commercial In-Service Date	December 2023
(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	+464 Acres
(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)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2023)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,212.76
	Direct Construction Cost ($/kW)	1,153.84
	AFUDC[2] Amount ($/kW)	58.92
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.39
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.15

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

Schedule 9
(Page 16 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Dover Solar
(2)	Net Capability	
	A. Summer	25MW-ac
	B. Winter	25MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	January 2023
	B. Commercial In-Service Date	December 2023
(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 (2023)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,375.11
	Direct Construction Cost ($/kW)	1,375.11
	AFUDC[2] Amount ($/kW)	-
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.39
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.13

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

Schedule 9
(Page 17 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Bayside 2 Enhancement
(2)	Net Capability	
	A. Summer	70 MW
	B. Winter	80 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	2023
	B. Commercial In-Service Date	November 2023
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2024)	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[2] (In-Service Year $/kW)	406.75
	Direct Construction Cost ($/kW)	397.98
	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	1.46

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

[2] Total installed cost includes transmission interconnection

Schedule 9
(Page 18 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Reciprocating Engine
(2)	Net Capability	
	A. Summer	37 MW (Consisting of 2 Units)
	B. Winter	37 MW (Consisting of 2 Units)
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	December 2021
	B. Commercial In-Service Date	December 2024
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	2%
	Forced Outage Factor (FOF)	2%
	Equivalent Availability Factor (EAF)	98%
	Resulting Capacity Factor (2023)	0.64%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	8,117 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	1,401.98
	Direct Construction Cost ($/kW)	1,080.01
	AFUDC[1] Amount ($/kW)	139.00
	Escalation ($/kW)	182.96
	Fixed O&M (In-Service Year $/kW – Yr)	22.04
	Variable O&M (In-Service Year $/MWh)	2.47
	K-Factor	1.51

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

Schedule 9
(Page 19 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 1 (Multiple Sites, each not to exceed 74.5MW)
(2)	Net Capability	
	A. Summer	150MW-ac
	B. Winter	150MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	2023
	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	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 (2024)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,227.68
	Direct Construction Cost ($/kW)	1,152.02
	AFUDC[2] Amount ($/kW)	75.65
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.64
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.28

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

Schedule 9
(Page 20 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage 1
(2)	Net Capability	
	A. Summer	50 MW
	B. Winter	50 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2024
	B. Commercial In-Service Date	December 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	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 (2025)	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[2] (In-Service Year $/kW)	810.52
	Direct Construction Cost ($/kW)	770.89
	AFUDC[1] Amount ($/kW)	39.63
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	17.98
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	1.37

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

Schedule 9
(Page 21 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage 2
(2)	Net Capability	
	A. Summer	50 MW
	B. Winter	50 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2025
	B. Commercial In-Service Date	December 2026
(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 (2026)	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[2] (In-Service Year $/kW)	791.17
	Direct Construction Cost ($/kW)	752.48
	AFUDC[1] Amount ($/kW)	38.69
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	17.86
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	1.38

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

Schedule 9
(Page 22 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 2 (Multiple Sites, each not to exceed 74.5MW)
(2)	Net Capability	
	A. Summer	150MW-ac
	B. Winter	150MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	2025
	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	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 (2026)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,202.22
	Direct Construction Cost ($/kW)	1,148.89
	AFUDC[2] Amount ($/kW)	53.33
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	12.16
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.24

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

Schedule 9
(Page 23 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage 3
(2)	Net Capability	
	A. Summer	50 MW
	B. Winter	50 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2026
	B. Commercial In-Service Date	December 2027
(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 (2027)	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[2] (In-Service Year $/kW)	1,201.32
	Direct Construction Cost ($/kW)	1,142.58
	AFUDC[1] Amount ($/kW)	58.74
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	23.98
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	1.35

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

Schedule 9
(Page 24 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage 4
(2)	Net Capability	
	A. Summer	50 MW
	B. Winter	50 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2027
	B. Commercial In-Service Date	December 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 (2028)	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[2] (In-Service Year $/kW)	1,192.97
	Direct Construction Cost ($/kW)	1,134.64
	AFUDC[1] Amount ($/kW)	58.33
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	24.03
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	1.35

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

Schedule 9
(Page 25 of 28)
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	150MW-ac
	B. Winter	150MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	2027
	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	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 (2028)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,199.05
	Direct Construction Cost ($/kW)	1,145.82
	AFUDC[2] Amount ($/kW)	53.22
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	12.70
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.26

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

Schedule 9
(Page 26 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage 5
(2)	Net Capability	
	A. Summer	50 MW
	B. Winter	50 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2028
	B. Commercial In-Service Date	December 2029
(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 (2029)	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[2] (In-Service Year $/kW)	1,186.96
	Direct Construction Cost ($/kW)	1,128.92
	AFUDC[1] Amount ($/kW)	58.04
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	24.13
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	1.36

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

Schedule 9
(Page 27 of 28)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage 6
(2)	Net Capability	
	A. Summer	50 MW
	B. Winter	50 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2029
	B. Commercial In-Service Date	December 2030
(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 (2030)	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[2] (In-Service Year $/kW)	1,193.05
	Direct Construction Cost ($/kW)	1,134.71
	AFUDC[1] Amount ($/kW)	58.34
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	24.40
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	1.36

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

Schedule 9
(Page 28 of 28)
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	150MW-ac
	B. Winter	150MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[4]	2029
	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 (2030)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[3] (In-Service Year $/kW)	1,195.93
	Direct Construction Cost ($/kW)	1,142.82
	AFUDC[2] Amount ($/kW)	53.11
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	13.26
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor[1]	1.28

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

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines
As of December 31, 2020

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
Durrance Solar	Polk - Durrance - Aspen	1	No ROW required	1	230 kV	January 2021	Included in total installed cost on Schedule 9	Durrance Solar Station; Polk & Aspen Substations	None
Jamison Solar	Polk - Jamison - Pebbledale	1	No ROW required	1	230 kV	December 2021	Included in total installed cost on Schedule 9	Jamison Solar Station; Polk & Pebbledale Substations	None
Big Bend CT 5	Big Bend CT 5 does not require any new transmission lines ****	-	-	-	230 kV	December 2021	-	Big Bend	None
Big Bend CT 6	Big Bend CT 6 does not require any new transmission lines ****	-	-	-	230 kV	December 2021	-	Big Bend	None
Bayside CC 1	Bayside CC 1 does not require any new transmission lines ****	-	-	-	230 kV	November 2022	-	Gannon	None
Big Bend ST 1	Big Bend ST 1 does not require any new transmission lines ****	-	-	-	230 kV	December 2022	-	Big Bend	None
Bayside CC 2	Bayside CC 2 does not require any new transmission lines ****	-	-	-	230 kV	November 2023	-	Gannon	None
Alafia Solar	Polk - Alafia	1	New ROW required	2	230 kV	December 2023	Included in total installed cost on Schedule 9	Alafia Solar Station; Polk 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.

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). All existing facilities are currently permitted as existing power plant sites. 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

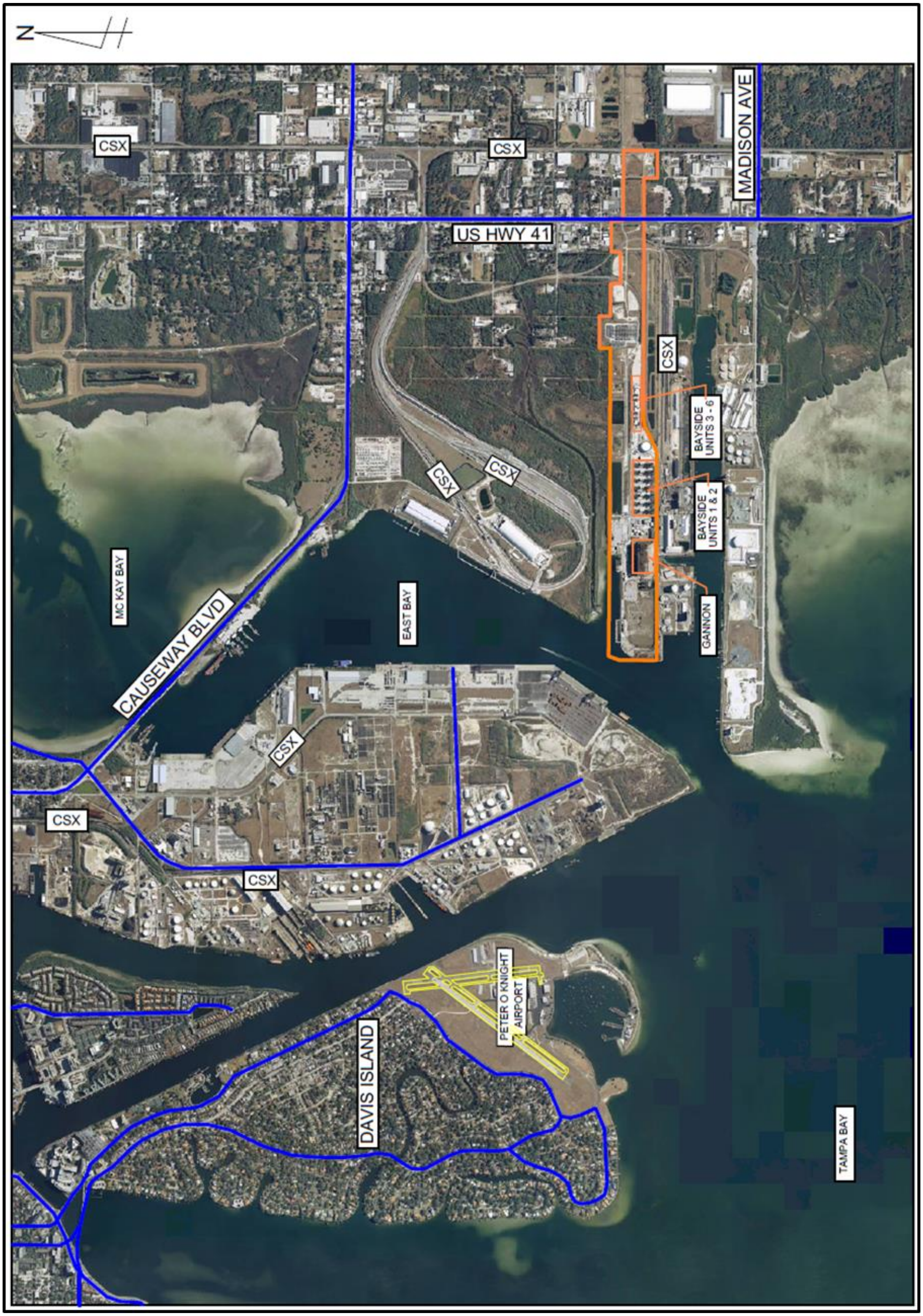


Figure VI-II: Site Location of Polk Power Station

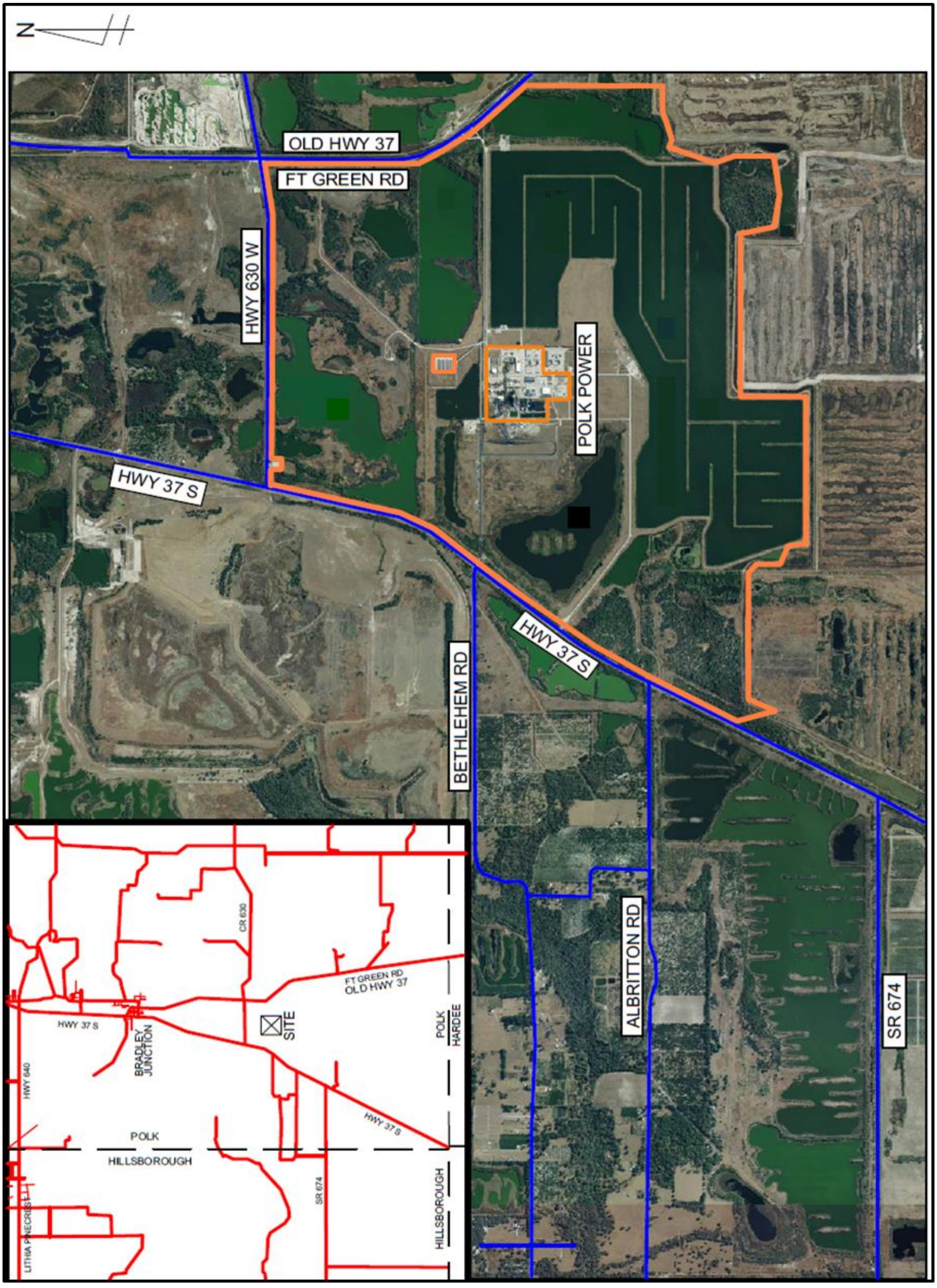


Figure VI-III: Site Location of Big Bend Power Station

Figure VI-IV: Site Location of Solar Power Stations